IDAHO POWER CO
Form 10-Q
October 29, 2009

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

(Mark One)

X	QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the quarterly period ended September 30, 2009 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	I.R.S. 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 State of Incorporation: Idaho Websites: www.idacorpinc.com, www.idahopower.com None	82-0130980

Former name, former address and former fiscal year, if changed since last report.

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).
Yes ___ No ___

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act (check one):

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 Exchange Act).
Yes ___ No _X_

Number of shares of Common Stock outstanding as of September 30, 2009:

IDACORP, Inc.:	47,650,036
Idaho Power Company:	39,150,812, all held by IDACORP, Inc.

This combined Form 10-Q 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 representations as to the information relating to IDACORP, Inc. s other operations.

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

COMMONLY USED TERMS

AFUDC	-	Allowance for Funds Used During Construction
APCU	-	Annual Power Cost Update
ASC	-	Accounting Standards Codification
Cal ISO	-	California Independent System Operator
CalPX	-	California Power Exchange
CAMP	-	Comprehensive Aquifer Management Plan
CO_2	-	Carbon Dioxide
EIS	-	Environmental impact statement
EPS	-	Earnings per share
ESA	-	Endangered Species Act
ESPA	-	Eastern Snake Plain Aquifer
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission
FIN	-	Financial Accounting Standards Board Interpretation
Fitch	-	Fitch Ratings, Inc.
GAAP	-	Generally Accepted Accounting Principles in the United States of America
HCC	-	Hells Canyon Complex
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
IDWR	-	Idaho Department of Water Resources
IE	-	IDACORP Energy, a subsidiary of IDACORP, Inc.
IERCO	-	Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPC	-	Idaho Power Company, a subsidiary of IDACORP, Inc.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
IWRB	-	Idaho Water Resource Board
kW	-	Kilowatt
LGAR	-	Load growth adjustment rate
maf	-	Million acre feet
MD&A	-	Management s Discussion and Analysis of Financial Condition and Results of Operations
Moody s	-	Moody s Investors Service
MW	-	Megawatt
MWh	-	Megawatt-hour
NO_x	-	Nitrogen Oxide

NWRFC	-	National Weather Service Northwest River Forecast Center
O&M	-	Operations and Maintenance
OATT	-	Open Access Transmission Tariff
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PCAM	-	Power Cost Adjustment Mechanism
PURPA	-	Public Utility Regulatory Policies Act of 1978
REC	-	Renewable Energy Certificate
RH BART	-	Regional Haze Best Available Retrofit Technology
RFP	-	Request for Proposal
S&P	-	Standard & Poor s Ratings Services
SFAS	-	Statement of Financial Accounting Standards
SO_2	-	Sulfur Dioxide
SRBA	-	Snake River Basin Adjudication
Valmy	-	North Valmy Steam Electric Generating Plant
VIEs	-	Variable Interest Entities

TABLE OF CONTENTS

SAFE HARBOR STATEMENT

This Form 10-Q contains forward-looking statements intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-Q at Part I, Item 2, Management s Discussion and Analysis of Financial Condition and Results of Operations Forward-Looking Information. Forward-looking statements are all statements other than statements of historical fact, including without limitation those that are identified by the use of the words anticipates, believes, estimates, expects, intends, plans, predicts, projec result, may continue, and similar expressions.

PART I FINANCIAL INFORMATION
Item 1. Financial Statements
IDACORP, Inc.
Condensed Consolidated Statements of Income
(unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2009	**2008**	**2009**	**2008**
	(thousands of dollars except for per share amounts)			
Operating Revenues:				
Electric utility:				
General business	$ 277,676	$ 246,639	$ 663,818	$ 602,700
Off-system sales	23,691	34,637	78,888	93,640
Other revenues	21,761	16,831	50,969	43,508
Total electric utility revenues	323,128	298,107	793,675	739,848
Other	1,381	1,609	3,042	3,534
Total operating revenues	324,509	299,716	796,717	743,382
Operating Expenses:				
Electric utility:				
Purchased power	73,483	79,513	131,370	174,900
Fuel expense	49,530	46,467	113,138	112,385
Third-party transmission expense	2,791	3,738	5,473	6,138
Power cost adjustment	1,614	(20,105)	44,236	(38,678)
Other operations and maintenance	68,970	71,040	212,392	213,183
Energy efficiency programs	12,202	5,956	24,933	13,249
Gain on sale of emission allowances	-	(158)	(289)	(504)
Depreciation	28,837	25,717	81,631	78,084
Taxes other than income taxes	5,600	4,827	15,749	14,431
Total electric utility expenses	243,027	216,995	628,633	573,188
Other expense	1,879	1,144	3,374	3,331
Total operating expenses	244,906	218,139	632,007	576,519
Operating Income (Loss):				
Electric utility	80,101	81,112	165,042	166,660
Other	(498)	465	(332)	203
Total operating income	79,603	81,577	164,710	166,863
Other Income , net	4,569	2,038	15,548	10,081
Income (Losses) of Unconsolidated Equity-Method Investments	2,866	2,642	648	(4,672)
Interest Expense:				
Interest on long-term debt	18,840	17,226	53,762	49,847

Other interest expense, net of AFUDC	(239)	1,310	481	3,219
Total interest expense	18,601	18,536	54,243	53,066
Income Before Income Taxes	68,437	67,721	126,663	119,206
Income Tax Expense	13,730	15,809	25,700	28,335
Net Income	54,707	51,912	100,963	90,871
Adjustment for (income) loss attributable to noncontrolling interests	(229)	(173)	(126)	98
Net Income Attributable to IDACORP, Inc.	$ 54,478	$ 51,739	$ 100,837	$ 90,969
Weighted Average Common Shares Outstanding - Basic (000 s)	47,068	45,126	46,953	45,044
Weighted Average Common Shares Outstanding - Diluted (000 s)	47,141	45,246	46,999	45,149
Earnings Per Share of Common Stock:				
Earnings Attributable to IDACORP Inc.-Basic	$ 1.16	$ 1.15	$ 2.15	$ 2.02
Earnings Attributable to IDACORP Inc.-Diluted	$ 1.16	$ 1.14	$ 2.15	$ 2.02
Dividends Paid Per Share of Common Stock	$ 0.30	$ 0.30	$ 0.90	$ 0.90

The accompanying notes are an integral part of these statements.

1

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

Assets	September 30, 2009	December 31, 2008
	(thousands of dollars)	
Current Assets:		
Cash and cash equivalents	$ 28,869	$ 8,828
Receivables:		
Customer	83,990	64,733
Allowance for uncollectible accounts	(1,534)	(1,724)
Other	12,242	10,439
Taxes receivable	-	18,111
Accrued unbilled revenues	49,779	43,934
Materials and supplies (at average cost)	50,599	50,121
Fuel stock (at average cost)	22,346	16,852
Prepayments	11,659	10,059
Deferred income taxes	14,739	37,550
Other	3,105	7,381
Total current assets	275,794	266,284
Investments	197,861	198,552
Property, Plant and Equipment:		
Utility plant in service	4,141,054	4,030,134
Accumulated provision for depreciation	(1,556,226)	(1,505,120)
Utility plant in service - net	2,584,828	2,525,014
Construction work in progress	236,632	207,662
Utility plant held for future use	6,549	6,318
Other property, net of accumulated depreciation	19,134	19,171
Property, plant and equipment - net	2,847,143	2,758,165
Other Assets:		
American Falls and Milner water rights	24,487	26,332
Company-owned life insurance	27,029	29,482
Regulatory assets	701,931	696,332
Long-term receivables (net of allowance of $1,684 and $2,478)	5,212	4,012
Other	37,835	43,686

Total other assets	796,494	799,844
Total	$ 4,117,292	$ 4,022,845

The accompanying notes are an integral part of these statements.

2

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

	September 30, 2009	**December 31, 2008**
Liabilities and Shareholders Equity	**(thousands of dollars)**	
Current Liabilities:		
Current maturities of long-term debt	$ 84,064	$ 86,528
Notes payable	36,780	151,250
Accounts payable	88,136	96,785
Taxes accrued	20,531	-
Interest accrued	27,680	16,727
Other	37,761	44,378
Total current liabilities	294,952	395,668
Other Liabilities:		
Deferred income taxes	528,953	515,719
Regulatory liabilities	285,695	276,266
Other	340,003	344,870
Total other liabilities	1,154,651	1,136,855
Long-Term Debt	1,282,900	1,183,451
Commitments and Contingencies		
Shareholders Equity:		
IDACORP, Inc. shareholders equity:		
Common stock, no par value (shares authorized 120,000,000; 47,679,227 and 46,929,203 shares issued, respectively)	747,402	729,576
Retained earnings	640,029	581,605
Accumulated other comprehensive loss	(6,900)	(8,707)
Treasury stock (29,191 and 9,022 shares at cost, respectively)	(53)	(37)
Total IDACORP, Inc. shareholders equity	1,380,478	1,302,437
Noncontrolling interest	4,311	4,434
Total shareholders equity	1,384,789	1,306,871
Total	$ 4,117,292	$ 4,022,845

The accompanying notes are an integral part of these statements.

3

IDACORP, Inc.
Condensed Consolidated Statements of Cash Flows
(unaudited)

	Nine months ended September 30,	
	2009	**2008**
Operating Activities:	**(thousands of dollars)**	
Net income	$ 100,963	$ 90,871
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	86,485	83,898
Deferred income taxes and investment tax credits	14,797	16,075
Changes in regulatory assets and liabilities	37,721	(50,081)
Non-cash pension expense	3,076	3,009
(Earnings) losses of equity method investments	(648)	4,672
Distributions from equity method investments	9,415	850
Gain on sale of assets	(417)	(3,369)
Other non-cash adjustments to net income, net	(764)	1,770
Change in:		
Accounts receivable and prepayments	(22,065)	(11,819)
Accounts payable and other accrued liabilities	(24,636)	(16,782)
Taxes accrued	38,812	6,244
Other current assets	(11,817)	(17,940)
Other current liabilities	5,850	8,971
Other assets	678	1,126
Other liabilities	(14,924)	(2,090)
Net cash provided by operating activities	222,526	115,405
Investing Activities:		
Additions to property, plant and equipment	(155,591)	(176,475)
Proceeds from the sale of non-utility assets	2,250	5,753
Investments in affordable housing	(6,176)	(8,486)
Proceeds from the sale of emission allowances	2,382	2,959

Investments in unconsolidated affiliates	-	(3,065)
Proceeds from the sale of investments	8,956	-
Purchase of held-to-maturity securities	-	(2,885)
Maturity of held-to-maturity securities	-	4,610
Withdrawal of refundable deposit for tax related liabilities	-	20,000
Other	683	(7,932)
Net cash used in investing activities	(147,496)	(165,521)
Financing Activities:		
Increase (decrease) in term loans	(170,000)	170,000
Issuance of long-term debt	100,000	120,000
Remarketing (purchase) of pollution control revenue bonds	166,100	(166,100)
Retirement of long-term debt	(9,174)	(7,630)
Dividends on common stock	(42,414)	(40,516)
Net change in short-term borrowings	(110,570)	13,570
Issuance of common stock	16,738	12,550
Acquisition of treasury stock	(1,441)	(304)
Other	(4,228)	(1,694)
Net cash (used in) provided by financing activities	(54,989)	99,876
Net increase in cash and cash equivalents	20,041	49,760
Cash and cash equivalents at beginning of the period	8,828	7,966
Cash and cash equivalents at end of the period	$ 28,869	$ 57,726
Supplemental Disclosure of Cash Flow Information:		
Cash paid during the period for:		
Income taxes (refunded) paid	$ (21,356)	$ 8,762
Interest (net of amount capitalized)	$ 41,227	$ 40,933
Non-cash investing activities:		
Additions to property, plant and equipment in accounts payable	$ 19,990	$ 10,527
Investments in affordable housing	$ 6,000	$ -

The accompanying notes are an integral part of these statements.

4

IDACORP, Inc.
Condensed Consolidated Statements of Comprehensive Income
(unaudited)

Three months ended

	September 30, 2009	2008
	(thousands of dollars)	
Net Income	$54,707	$51,912
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net unrealized holding gains (losses) arising during the period, net of tax of $734 and ($791)	1,143	(1,232)
Unfunded pension liability adjustment, net of tax of $87 and $67	136	104
Total Comprehensive Income	55,986	50,784
Comprehensive income attributable to noncontrolling interests	(229)	(173)
Comprehensive Income attributable to IDACORP, Inc. common shareholders	$55,757	$50,611

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Condensed Consolidated Statements of Comprehensive Income
(unaudited)

	Nine months ended September 30, 2009	2008
	(thousands of dollars)	
Net Income	$100,963	$90,871
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net unrealized holding gains (losses) arising during the period, net of tax of $898 and ($1,679)	1,399	(2,616)
Unfunded pension liability adjustment, net of tax of $261 and $200	408	311
Total Comprehensive Income	102,770	88,566
Comprehensive (income) loss attributable to noncontrolling interests	(126)	98
Comprehensive Income attributable to IDACORP, Inc. common shareholders	$102,644	$88,664

The accompanying notes are an integral part of these statements.

5

Idaho Power Company
Condensed Consolidated Statements of Income
(unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2009	**2008**	**2009**	**2008**
	(thousands of dollars)			
Operating Revenues:				
General business	$ 277,676	$ 246,639	$ 663,818	$ 602,700
Off-system sales	23,691	34,637	78,888	93,640
Other revenues	21,761	16,831	50,969	43,508
Total operating revenues	323,128	298,107	793,675	739,848
Operating Expenses:				
Operation:				
Purchased power	73,483	79,513	131,370	174,900
Fuel expense	49,530	46,467	113,138	112,385
Third-party transmission expense	2,791	3,738	5,473	6,138
Power cost adjustment	1,614	(20,105)	44,236	(38,678)
Other	52,495	54,806	159,420	162,537
Energy efficiency programs	12,202	5,956	24,933	13,249
Gain on sale of emission allowances	-	(158)	(289)	(504)
Maintenance	16,475	16,234	52,972	50,646
Depreciation	28,837	25,717	81,631	78,084
Taxes other than income taxes	5,600	4,827	15,749	14,431
Total operating expenses	243,027	216,995	628,633	573,188
Income from Operations	80,101	81,112	165,042	166,660
Other Income:				
Allowance for equity funds used during construction	2,131	1,265	4,629	2,394
Earnings of unconsolidated equity-method investments	4,328	4,487	6,980	2,621
Other income, net	1,717	825	9,662	7,425
Total other income	8,176	6,577	21,271	12,440
Interest Charges:				
Interest on long-term debt	18,826	16,916	53,661	48,868
Other interest	1,302	2,290	4,230	6,437
Allowance for borrowed funds used during construction	(1,654)	(1,549)	(4,439)	(4,966)
Total interest charges	18,474	17,657	53,452	50,339
Income Before Income Taxes	69,803	70,032	132,861	128,761

Income Tax Expense	18,746	22,627	36,194	42,357
Net Income	$ 51,057	$ 47,405	$ 96,667	$ 86,404

The accompanying notes are an integral part of these statements.

6

Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

	September 30, 2009	December 31, 2008
Assets	(thousands of dollars)	
Electric Plant:		
In service (at original cost)	$ 4,141,054	$ 4,030,134
Accumulated provision for depreciation	(1,556,226)	(1,505,120)
In service - net	2,584,828	2,525,014
Construction work in progress	236,632	207,662
Held for future use	6,549	6,318
Electric plant - net	2,828,009	2,738,994
Investments and Other Property	108,747	106,057
Current Assets:		
Cash and cash equivalents	20,334	3,141
Receivables:		
Customer	83,990	64,433
Allowance for uncollectible accounts	(1,499)	(1,724)
Other	10,278	7,947
Taxes receivable	-	41,363
Accrued unbilled revenues	49,779	43,934
Materials and supplies (at average cost)	50,599	50,121
Fuel stock (at average cost)	22,346	16,852
Prepayments	11,489	9,865
Deferred income taxes	3,922	3,852
Other	2,269	4,968
Total current assets	253,507	244,752
Deferred Debits:		
American Falls and Milner water rights	24,487	26,332
Company-owned life insurance	27,029	29,482
Regulatory assets	701,931	696,332
Other	37,047	42,907
Total deferred debits	790,494	795,053
Total	$ 3,980,757	$ 3,884,856

The accompanying notes are an integral part of these statements.

7

Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

Capitalization and Liabilities	September 30, 2009	December 31, 2008
	(thousands of dollars)	
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	638,758	618,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	536,155	482,047
Accumulated other comprehensive loss	(6,900)	(8,707)
Total common stock equity	1,263,793	1,187,878
Long-term debt	1,279,900	1,180,691
Total capitalization	2,543,693	2,368,569
Current Liabilities:		
Long-term debt due within one year	81,064	81,064
Notes payable	-	112,850
Accounts payable	85,971	96,268
Notes and accounts payable to related parties	1,265	768
Taxes accrued	478	-
Interest accrued	27,680	16,675
Other	36,928	43,274
Total current liabilities	233,386	350,899
Deferred Credits:		
Deferred income taxes	580,896	547,159
Regulatory liabilities	285,695	276,266
Other	337,087	341,963
Total deferred credits	1,203,678	1,165,388
Commitments and Contingencies		
Total	$ 3,980,757	$ 3,884,856

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Statements of Capitalization
(unaudited)

	September 30, 2009	**%**	**December 31, 2008**	**%**
	(thousands of dollars)			
Common Stock Equity:				
Common stock	$ 97,877		$ 97,877	
Premium on capital stock	638,758		618,758	
Capital stock expense	(2,097)		(2,097)	
Retained earnings	536,155		482,047	
Accumulated other comprehensive loss	(6,900)		(8,707)	
Total common stock equity	1,263,793	50	1,187,878	50
Long-Term Debt:				
First mortgage bonds:				
7.20% Series due 2009	80,000		80,000	
6.60% Series due 2011	120,000		120,000	
4.75% Series due 2012	100,000		100,000	
4.25% Series due 2013	70,000		70,000	
6.025% Series due 2018	120,000		120,000	
6.15% Series due 2019	100,000		-	
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	
Total first mortgage bonds	1,165,000		1,065,000	
Amount due within one year	(80,000)		(80,000)	

Net first mortgage bonds		1,085,000			985,000	
Pollution control revenue bonds:						
5.15% Series due 2024		49,800			49,800	
5.25% Series due 2026		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		8,509			9,573	
Note guarantee due within one year		(1,064)			(1,064)	
Unamortized premium/discount - net		(2,890)			(3,163)	
Term Loan Credit Facility		-			166,100	
Purchase of pollution control revenue bonds		-			(166,100)	
Total long-term debt		1,279,900	50		1,180,691	50
Total Capitalization	$	2,543,693	100	$	2,368,569	100

The accompanying notes are an integral part of these statements.

9

Idaho Power Company

Condensed Consolidated Statements of Cash Flows (unaudited)

	Nine months ended September 30,	
	2009	**2008**
	(thousands of dollars)	
Operating Activities:		
Net income	$ 96,667	$ 86,404
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	85,922	83,285
Deferred income taxes and investment tax credits	12,419	15,173
Changes in regulatory assets and liabilities	37,721	(50,081)
Non-cash pension expense	3,076	3,009
Earnings of equity method investments	(6,980)	(2,621)
Distributions from equity method investments	8,340	-
Gain on sale of assets	(442)	(3,383)
Other non-cash adjustments to net income	(2,516)	(1,346)
Change in:		
Accounts receivables and prepayments	(21,940)	(12,162)
Accounts payable	(26,283)	(16,175)
Taxes accrued	41,996	21,636
Other current assets	(11,817)	(17,939)
Other current liabilities	6,029	8,945
Other assets	678	1,121
Other liabilities	(14,983)	(1,888)
Net cash provided by operating activities	207,887	113,978
Investing Activities:		
Additions to utility plant	(155,591)	(176,475)
Proceeds from the sale of non-utility assets	2,250	5,690
Proceeds from sale of emission allowances	2,382	2,959
Investments in unconsolidated affiliates	-	(3,065)
Withdrawal of refundable deposit for tax related liabilities	-	20,000
Other	648	(7,550)
Net cash used in investing activities	(150,311)	(158,441)
Financing Activities:		
Increase (decrease) in term loans	(170,000)	170,000
Issuance of long-term debt	100,000	120,000

Remarketing (purchase) of pollution control revenue bonds	166,100	(166,100)
Retirement of long-term debt	(1,064)	(1,064)
Dividends on common stock	(42,560)	(40,678)
Net change in short term borrowings	(108,950)	(5,222)
Capital contribution from parent	20,000	-
Other	(3,909)	(1,631)
Net cash (used in) provided by financing activities	(40,383)	75,305
Net increase in cash and cash equivalents	17,193	30,842
Cash and cash equivalents at beginning of the period	3,141	5,347
Cash and cash equivalents at end of the period	$ 20,334	$ 36,189
Supplemental Disclosure of Cash Flow Information:		
Cash paid during the period for:		
Income taxes (received from) paid to parent	$ (11,668)	$ 8,331
Interest (net of amount capitalized)	$ 40,505	$ 38,300
Non-cash investing activities:		
Additions to property, plant and equipment in accounts payable	$ 19,990	$ 10,527

The accompanying notes are an integral part of these statements.

10

Idaho Power Company
Condensed Consolidated Statements of Comprehensive Income
(unaudited)

	Three months ended September 30,	
	2009	**2008**
	(thousands of dollars)	
Net Income	$ 51,057	$ 47,405
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net unrealized holding gains (losses) arising during the period, net of tax of $734 and ($791)	1,143	(1,232)
Unfunded pension liability adjustment, net of tax of $87 and $67	136	104
Total Comprehensive Income	$ 52,336	$ 46,277

The accompanying notes are an integral part of these statements.

Idaho Power Company
Condensed Consolidated Statements of Comprehensive Income
(unaudited)

	Nine months ended September 30,	
	2009	**2008**
	(thousands of dollars)	
Net Income	$ 96,667	$ 86,404
Other Comprehensive Income (Loss):		
Unrealized gains (losses) on securities:		
Net unrealized holding gains (losses) arising during the period, net of tax of $898 and ($1,679)	1,399	(2,616)
Unfunded pension liability adjustment, net of tax of $261 and $200	408	311
Total Comprehensive Income	$ 98,474	$ 84,099

The accompanying notes are an integral part of these statements.

11

IDACORP, INC. AND IDAHO POWER COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

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

Nature of Business

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

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

IDACORP s other subsidiaries include:

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

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

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

Principles of Consolidation

IDACORP s and IPC s condensed 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. All significant 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 IPC 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). Marysville has approximately $26 million of assets, primarily a small hydroelectric plant, and approximately $17 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 results in it absorbing a majority of the expected losses of 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.

Through IFS and Ida-West, IDACORP also holds variable interests in VIEs for which it is not the primary beneficiary. These interests are presented as Investments on IDACORP s condensed consolidated balance sheets. IFS investments in VIEs are affordable housing and historic rehabilitation developments in which IFS holds limited partnership interests ranging from five to 99 percent. These investments were acquired between 1996 and 2009, and are not consolidated because IFS does not absorb a majority of the expected losses of these entities, either because of specific provisions in the partnership agreements or due to not owning a majority interest. IFS s maximum exposure to loss in these developments is limited to its net carrying value, which was $79 million at September 30, 2009. Ida-West has 50 percent ownership of three other joint ventures that are not consolidated because Ida-West does not absorb a majority of the expected losses. Ida-West s maximum exposure to loss in these joint ventures is limited to its net carrying value, which was $11 million at September 30, 2009.

Financial Statements

In the opinion of IDACORP and IPC, the accompanying unaudited condensed consolidated financial statements contain all adjustments necessary to present fairly their consolidated financial positions as of September 30, 2009, and consolidated results of operations for the three and nine months ended September 30, 2009, and 2008, and consolidated cash flows for the nine months ended September 30, 2009, and 2008. These adjustments are of a normal and recurring nature. These financial statements do not contain the complete detail or footnote disclosure concerning accounting policies and other matters that would be included in full-year financial statements, and should be read in conjunction with the audited consolidated financial statements included in IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year.

Subsequent Events

In the preparation of these financial statements, IDACORP and IPC evaluate all subsequent events that provide additional evidence about conditions that existed at the date of the balance sheet. Subsequent events were evaluated through October 29, 2009, up to the time the financial statements were issued.

Reclassifications

Certain prior year amounts have been reclassified to conform to the current year presentation. The reclassifications made to prior year amounts include the following:

Other expense was combined with the other income line in IDACORP s and IPC s condensed consolidated statements of income to present information in a more condensed manner;

Third-party transmission expense was broken out from electric utility other operations and maintenance in IDACORP s condensed consolidated statements of income and from other operation in IPC s condensed consolidated statements of income because third-party transmission costs are now treated as a power supply cost in the power cost adjustment (PCA);

Employee notes current was combined with other current receivables and employee notes long-term was combined with other non-current assets in IDACORP s and IPC s condensed consolidated balance sheets due to the employee notes becoming an immaterial balance; and

Uncertain tax positions was combined with other current liabilities in IDACORP s and IPC s condensed consolidated balance sheets due to the uncertain tax positions becoming an immaterial balance.

Revenues

Operating revenues for IPC related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at period-end. IPC collects franchise fees and similar taxes related to energy consumption. These amounts are recorded as liabilities until paid to the taxing authority. None of these collections are reported on the income statement as revenue or expense. Beginning in February 2009, IPC is collecting AFUDC in base rates for a specific capital project, as discussed in Note 6, Regulatory Matters. Cash collected under this ratemaking mechanism is recorded as a regulatory liability.

Allowance for Funds Used during Construction (AFUDC)

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, cash is not realized currently from such allowance, it is realized under the rate-making process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income.

Earnings Per Share (EPS)

In January 2009, IDACORP adopted accounting guidance that clarified that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPS pursuant to the two-class method. Prior-period EPS data has been adjusted retrospectively. Adoption of this guidance did not have a material impact on IDACORP s EPS and had no impact on IPC s condensed consolidated financial statements. The following table presents the computation of IDACORP s basic and diluted earnings per share for the three and nine months ended September 30, 2009 and 2008 (in thousands, except for per share amounts):

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
Numerator:				
Net income attributable to IDACORP, Inc.	$ 54,478	$ 51,739	$ 100,837	$ 90,969
Denominator:				
Weighted-average common shares outstanding - basic	47,068	45,126	46,953	45,044
Effect of dilutive securities:				
Options	15	32	12	43
Restricted Stock	58	88	34	62
Weighted-average common shares outstanding diluted	47,141	45,246	46,999	45,149
Basic earnings per share	$ 1.16	$ 1.15	$ 2.15	$ 2.02
Diluted earnings per share	$ 1.16	$ 1.14	$ 2.15	$ 2.02

The diluted EPS computation excluded 548,957 and 640,674 options for the three and nine months ended September 30, 2009, respectively, because the options exercise prices were greater than the average market price of the common stock during those periods. For the same periods last year, 577,585 and 513,862 options were excluded from the diluted EPS computation for the same reason. In total, 636,753 options were outstanding at September 30, 2009, with expiration dates between 2010 and 2015.

Adoption of Guidance on Noncontrolling Interests

On January 1, 2009, IDACORP and IPC adopted guidance related to presentation of noncontrolling interests in consolidated subsidiaries (previously referred to as minority interests). This guidance clarified that noncontrolling interests should be reported as equity on the consolidated financial statements. IDACORP has disclosed in its financial statements the portion of equity and net income attributable to the noncontrolling interests in consolidated subsidiaries and has reclassified $4 million of noncontrolling interests from other liabilities to shareholders equity on the December 31, 2008, balance sheet. IPC does not have any noncontrolling interests. The adoption of this guidance modifies financial statement presentation, but does not impact financial statement results.

The following table presents a reconciliation of the carrying amount of shareholders equity (in thousands):

	Attributable to IDACORP, Inc.	Attributable to noncontrolling interests	Total
Shareholders equity at January 1, 2009	$ 1,302,437	$ 4,434	$ 1,306,871
Net income	100,837	126	100,963
Common stock dividends	(42,413)	-	(42,413)
Common stock issuances	17,061	-	17,061
Common stock acquired	(1,441)	-	(1,441)
Unrealized holding gains on securities	1,399	-	1,399
Unfunded pension liability adjustment	408	-	408
Other	2,190	(249)	1,941
Shareholders equity at September 30, 2009	$ 1,380,478	$ 4,311	$ 1,384,789
Shareholders equity at January 1, 2008	$ 1,207,315	$ 4,478	$ 1,211,793
Net income (loss)	90,969	(98)	90,871
Common stock dividends	(40,671)	-	(40,671)
Common stock issuances	12,647	-	12,647
Common stock acquired	(304)	-	(304)
Unrealized holding losses on securities	(2,616)	-	(2,616)
Unfunded pension liability adjustment	311	-	311
Other	3,009	(7)	3,002
Shareholders equity at September 30, 2008	$ 1,270,660	$ 4,373	$ 1,275,033

New and Adopted Accounting Pronouncements

The Financial Accounting Standards Board (FASB) has issued several new accounting pronouncements. IDACORP and IPC have adopted these pronouncements in 2009:

On January 1, 2009, IDACORP and IPC adopted guidance related to business combinations. This guidance establishes principles and requirements for how an acquirer in a business combination: (1) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. In April 2009, the FASB issued guidance further clarifying the application of the standard. The guidance primarily relates to business combinations entered into after December 31, 2009, and has not impacted IDACORP s or IPC s consolidated financial statements.

On January 1, 2009, IDACORP and IPC adopted guidance that changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why it uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under prior guidance, and (3) how derivative instruments and related hedged items affect its financial position, financial performance, and cash flows. The adoption of this guidance is reflected in Note 10, and did not otherwise impact IDACORP s or IPC s consolidated financial statements.

On January 1, 2009, IDACORP and IPC adopted guidance related to goodwill and other intangible assets. This guidance removes the requirement that an entity must consider, when determining the useful life of an acquired intangible asset, whether the intangible asset can be renewed without substantial cost or material modifications to the existing terms and conditions associated with the intangible asset. The guidance now requires that an entity consider its own experience in renewing similar arrangements. If the entity has no relevant experience, it would consider market participant assumptions regarding renewal. The adoption of this guidance did not impact IDACORP s or IPC s consolidated financial statements.

In June 2009, IDACORP and IPC adopted guidance on accounting for and disclosures of subsequent events, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The required new disclosures are made earlier in this note, and this guidance has not otherwise impacted IDACORP s or IPC s consolidated financial statements.

Fair Value Measurements: In the first quarter of 2009, IDACORP and IPC adopted the following fair value guidance:

a. Guidelines for making fair value measurements more consistent by providing guidance related to determining fair values when there is no active market or where the price inputs being used represent distressed sales;

b. Guidance that enhances consistency in financial reporting by increasing the frequency of fair value disclosures by requiring quarterly fair value disclosures for any financial instruments that are not currently reflected on the balance sheet of companies at fair value and requires qualitative and quantitative information about fair value estimates for all such financial instruments; and

c. Guidance on other-than-temporary impairments that brings greater consistency to the timing of impairment recognition, and provides greater clarity to investors about the credit and noncredit components of impaired debt securities that are not expected to be sold. The guidance also requires increased and timelier disclosures sought by investors regarding expected cash flows, credit losses, and the aging of securities with unrealized losses.

The adoption of this guidance did not have a material effect on IDACORP s or IPC s consolidated financial statements.

Effective for financial statements issued for interim and annual periods ending after September 15, 2009, *The FASB Accounting Standards Codification ™* became the source of authoritative U.S. generally accepted accounting principles recognized by the FASB to be applied to nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP to SEC registrants. On the effective date, the Codification superseded, but did not change, all then-existing non-SEC accounting and reporting standards, and all other nongrandfathered, non-SEC accounting literature not included in the codification became nonauthoritative. Transition to the Codification did not affect IDACORP s or IPC s results of operations, cash flows or financial positions. This Form 10-Q reflects the implementation of the Codification.

The FASB has also issued the following accounting guidance that becomes effective in future periods:

In December 2008, the FASB issued guidance on enhanced disclosures about retirement plan assets. This guidance will require companies to provide users of financial statements with an understanding of: (1) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (2) the major categories of plan assets; (3) the inputs and valuation techniques used to measure the fair value of plan assets; (4) the effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and (5) significant concentrations of risk within plan assets. This guidance is effective for fiscal years ending after December 15, 2009. IDACORP and IPC do not expect the adoption of this guidance to have a material effect on their consolidated financial statements.

In June 2009, the FASB issued guidance on how the transferor and transferee should separately account for a transfer of a financial asset and a related repurchase financing if certain criteria are met. For IDACORP and IPC, this guidance is effective for financial asset transfers occurring on or after January 1, 2010, and early adoption is prohibited. IDACORP and IPC do not expect the adoption of this guidance to have a material effect on their consolidated financial statements.

In June 2009, the FASB issued amendments to prior consolidation guidance. The amendments will significantly affect the overall consolidation analysis of VIEs. The amendments will require IDACORP and IPC to reconsider their previous conclusions relating to the consolidation of VIEs, including (1) whether an entity is a VIE, (2) whether the enterprise is the VIE s primary beneficiary, and (3) what type of financial statement disclosures are required. For IDACORP and IPC, the amendments are effective as of January 1, 2010, and early adoption is prohibited. IDACORP and IPC are currently assessing the impact of the amendments on their consolidated financial statements.

Accounting Standards Updates (ASUs) The FASB has issued several amendments to the Codification in the form of ASUs No. 2009-01 through 2009-15. IDACORP and IPC are evaluating the provisions of these amendments. Several of these ASUs are not applicable to IDACORP and IPC and are not included in the following discussion. IDACORP and IPC expect the following ASU to be relevant, but does not expect it to have a material impact on IDACORP s or IPC s consolidated financial statements:

o **ASU 2009-05** provides clarification of measurement techniques to be used in circumstances in which a quoted price in an active market for the identical liability is not available and provides other fair value guidance. This guidance is effective for the first reporting period beginning after issuance. IDACORP and IPC will adopt the guidance in their December 31, 2009, financial statements.

2. INCOME TAXES:

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP s effective tax rate for the nine months ended September 30, 2009, was 20.3 percent, compared to 23.8 percent for the nine months ended September 30, 2008. IPC s effective tax rate for the nine months ended September 30, 2009, was 27.2 percent, compared to 32.9 percent for the nine months ended September 30, 2008. The decrease in the 2009 estimated annual effective tax rates from 2008 was primarily due to an examination settlement, state bonus depreciation, and timing and amount of other regulatory flow-through tax adjustments at IPC. The decreases were partially offset by additional income tax expense from greater pre-tax earnings at IDACORP and IPC, and lower tax credits from IFS.

In April 2009, the State of Idaho adopted the federal bonus depreciation provisions enacted as part of the American Recovery and Reinvestment Act of 2009. IPC s regulatory tax accounting method allows for the flow-through of certain state tax adjustments, including accelerated depreciation. Due to the application of the bonus depreciation provision, IPC was able to reduce its income tax expense by $2.2 million for the nine months ended September 30, 2009.

The Internal Revenue Service (IRS) completed its examination of IDACORP s 2006 tax year in May 2009. The 2006 examination report was submitted for U.S. Congress Joint Committee on Taxation (JCT) review in June. In July, the JCT completed its review and accepted the report without change. IDACORP considered all uncertain tax positions related to its 2006 tax year effectively settled as of the second quarter, and decreased IPC s liability for unrecognized tax benefits by $1.3 million.

In March 2009, the JCT completed its review of IDACORP s 2001-2004 uniform capitalization appeals settlement and 2005 IRS examination report. The JCT accepted both items without change. IDACORP considered these matters effectively settled in 2008 and recorded the related financial effects in its December 31, 2008, financial statements.

The IRS began its examination of IDACORP s 2007-2008 tax years in July 2009. In May 2009, IDACORP formally entered the IRS Compliance Assurance Process (CAP) program for its 2009 tax year. The CAP program provides for IRS examination throughout the year. The 2007-2009 examinations are expected to be completed in 2010. IDACORP and IPC are unable to predict the outcome of these examinations.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

During the nine months ended September 30, 2009, IDACORP entered into the following transactions involving its common stock:

In September 2009, 326,307 original issue shares were issued in at-the-market offerings at an average price of $28.63 per share through the continuous equity program (CEP). An additional 163,053 shares sold in September 2009 settled in October 2009 at an average price of $29.10 per share.

112,128 original issue shares and 24,948 treasury shares were used for awards granted under the 2000 Long-Term Incentive and Compensation Plan.

28,518 original issue shares and 22,550 treasury shares were used for awards granted under the Restricted Stock Plan.

12,936 treasury shares were used for the annual stock grant to directors under the Non-Employee Directors Stock Compensation Plan.

283,071 original issue shares were issued under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings Plan.

IDACORP has a Sales Agency Agreement with BNY Mellon Capital Markets, LLC, as IDACORP s agent, for the offer and sale of up to 3,000,000 shares of its common stock from time to time in at-the-market offerings. At September 30, 2009, there were 2,301,871 shares remaining available for sale under the CEP. At October 29, 2009 there were 2,138,818 shares remaining available.

IDACORP contributed $20 million in cash as additional equity to IPC in September 2009. No additional shares of IPC common stock were issued.

IDACORP has three share-based compensation plans. IDACORP s employee plans are the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP s long-term growth. IDACORP also has one non-employee plan, the Non-Employee Directors Stock Compensation Plan (DSP). The purpose of the DSP is to increase directors stock ownership through stock-based compensation.

The LTICP for officers, key employees and directors permits the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares and other awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At September 30, 2009, the maximum number of shares available under the LTICP and RSP were 1,597,309 and 25,515, respectively.

The following table shows the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to IPC for those costs associated with IPC s employees (in thousands of dollars). No equity compensation costs have been capitalized:

	IDACORP Nine months ended September 30,		IPC Nine months ended September 30,	
	2009	2008	2009	2008
Compensation cost	$ 2,711	$ 3,106	$ 2,570	$ 2,933
Income tax benefit	$ 1,060	$ 1,214	$ 1,005	$ 1,147

Stock awards: Restricted stock awards have vesting periods of up to three years. Restricted stock awards entitle the recipients to dividends and voting rights, and unvested shares are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of restricted stock awards is measured based on the market price of the underlying common stock on the date of grant and is charged to compensation expense over the vesting period based on the number of shares expected to vest. The weighted average fair value at date of grant for restricted stock awards granted during 2009 was $25.48.

Performance-based restricted stock awards have vesting periods of three years. Performance awards entitle the recipients to voting rights, and unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. Dividends are accrued during the vesting period and will be paid out only on shares that eventually vest.

The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments, using an expected quarterly dividend of $0.30. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest. The weighted average fair value at date of grant for CEPS and TSR awards granted during the first nine months of 2009 was $19.50.

Stock option awards are granted with exercise prices equal to the market value of the stock on the date of grant. The options have a term of 10 years from the grant date and vest over a five-year period. The fair value of each option is amortized into compensation expense using graded-vesting. Stock options are not a significant component of share-based compensation awards under the LTICP.

4. LONG-TERM DEBT:

Long-Term Financing

As of September 30, 2009, IDACORP had approximately $579 million remaining on a shelf registration statement that can be used for the issuance of debt securities or common stock. As of October 29, 2009, IDACORP had approximately $574 remaining available on the shelf registration statement.

On March 30, 2009, IPC issued $100 million of 6.15 percent first mortgage bonds, due April 1, 2019. IPC used the net proceeds to repay a portion of its short-term debt in anticipation of utilizing short-term debt to repay $80 million of 7.20 percent first mortgage bonds that mature December 1, 2009. IPC has $130 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt.

In February 2009, IFS repaid $7.2 million of debt related to investments in affordable housing. The debt was scheduled to mature in 2009 and 2010. On May 15, 2009, IFS issued a $6 million equity funding obligation to finance a portion of its $12 million investment in affordable housing. The obligation is scheduled to mature in 2010.

Pollution Control Revenue Refunding Bonds and Term Loan Credit Agreement: On April 3, 2008, IPC made a mandatory purchase of two series of Pollution Control Revenue Refunding Bonds issued for the benefit of IPC, the

$116.3 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2006 issued by Sweetwater County, Wyoming due 2026 and the $49.8 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2003 issued by Humboldt County, Nevada due 2024 (together the Pollution Control Bonds). IPC initiated this transaction in order to adjust the interest rate period of the Pollution Control Bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008. This change was made to mitigate the higher-than-anticipated interest costs in the auction mode, which was a result of the financial guarantor s credit ratings deterioration.

On August 20, 2009, J.P. Morgan Securities Inc. as the Remarketing Agent, purchased the Pollution Control Bonds from IPC for remarketing to the public. The Humboldt County Bonds carry a 5.15 percent term interest rate and mature on December 1, 2024. The Sweetwater County Bonds carry a 5.25 percent term interest rate and mature on July 15, 2026. The Pollution Control Bonds are not subject to redemption for 10 years, except for extraordinary optional and mandatory redemption prior to maturity, in each case at 100 percent of the principal amount, plus accrued interest if any to the date of redemption. In connection with the remarketing of the Pollution Control Bonds, the financial guaranty insurance policies securing the Pollution Control Bonds were terminated.

On August 25, 2009, IPC used proceeds from the reoffering of the Pollution Control Bonds and additional corporate funds to prepay its $170 million loan under a Term Loan Credit Agreement dated as of February 4, 2009, among JPMorgan Chase Bank, N.A., as administrative agent and lender, Bank of America, N.A. and Wachovia Bank, National Association, as lenders.

5. NOTES PAYABLE:

Credit Facilities

IDACORP has a $100 million credit facility and IPC has a $300 million credit facility, both of which expire on April 25, 2012. Commercial paper may be issued up to the amounts supported by the bank credit facilities. Under these facilities the companies pay a facility fee on the commitment, quarterly in arrears, based on its rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody s and S&P.

At September 30, 2009, no loans were outstanding on either IDACORP s facility or IPC s facility. At September 30, 2009, IPC had regulatory authority to incur up to $450 million of short-term indebtedness.

Balances and interest rates of short-term borrowings were as follows at September 30, 2009, and December 31, 2008 (in thousands of dollars):

	September 30, 2009			**December 31, 2008**		
	IPC	**IDACORP**	**Total**	**IPC**	**IDACORP**	**Total**
Commercial paper outstanding	$ -	$ 36,780	$ 36,780	$ 108,950	$ 13,400	$ 122,350
Other short-term borrowings	-	-	-	3,900	25,000	28,900
Total	$ -	$ 36,780	$ 36,780	$ 112,850	$ 38,400	$ 151,250
Weighted-average. interest rate	0.00%	0.44%	0.44%	4.89%	4.29%	4.74%

6. REGULATORY MATTERS:

Idaho 2008 General Rate Case

On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. On February 19, 2009, IPC filed a request for reconsideration with the IPUC and on March 19, 2009, the IPUC issued an order that increased IPC s Idaho revenue requirement by an additional $6.1 million to approximately $27 million for this rate case, raising the average rate increase from 3.1 percent to 4.0 percent.

The IPUC denied reconsideration with respect to a refund of $3.3 million of fees recovered by IPC from the FERC. On April 2, 2009, IPC filed an application with the IPUC for an accounting order approving amortization of the fees over a five year period beginning October 2006 when IPC received the FERC credit. The IPUC approved IPC s requested amortization period in an order issued on April 28, 2009. In the first quarter of 2009, IPC recorded a charge of approximately $1.7 million to electric utility other operations expense and a corresponding regulatory liability for the amount to be refunded from February 1, 2009, through the end of the amortization period, September 2011. As the regulatory liability is amortized it will reduce electric utility other operations expense ratably over the remaining amortization period.

The January 30, 2009 order authorized approximately $15 million related to increases in base net power supply costs. It also allowed IPC to include in rates approximately $6.8 million ($10.6 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase will improve cash flows but will not have a current impact on IPC s net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

Deferred Net Power Supply Costs

IPC s deferred net power supply costs consisted of the following balances, including applicable carrying charges (in thousands of dollars):

	September 30, 2009		December 31, 2008	
Idaho PCA current year:				
Deferral for the 2009-2010 rate year	$	-	$	93,657
Deferral for the 2010-2011 rate year		26,121		-
Idaho PCA true-up awaiting recovery:				
Authorized in May 2008		-		47,164
Authorized in May 2009		66,716		-
Oregon deferral:				
2001 Costs		-		1,663
2006 Costs		2,285		1,215
2007 Costs		6,105		-
2008 Power cost adjustment mechanism		5,725		5,400
Total deferral	$	106,952	$	149,099

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks IPC s actual net power supply costs (fuel, purchased power and third-party transmission expenses less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates.

The annual adjustments are based on two components:

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

A true-up component, based on the difference between the previous year s actual net power supply costs and the previous year s forecast. This 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 true-up component is calculated monthly, and interest is applied to the balance.

Prior to February 1, 2009, the PCA mechanism provided that 90 percent of deviations in power supply costs were to be reflected in IPC s rates for both the forecast and the true-up components. Effective February 1, 2009, this sharing percentage was changed to 95 percent.

2009-2010 PCA: On May 29, 2009, the IPUC approved the 2009-2010 PCA of $84.3 million or 10.2 percent, effective June 1, 2009. The 2009-2010 PCA reflects a new methodology discussed in PCA Workshops below that utilizes IPC s most recent operating plan to forecast power supply expenses rather than the previous method based on a forecast of Brownlee Reservoir inflow and a regression formula.

2008-2009 PCA: On May 30, 2008, the IPUC approved IPC s 2008-2009 PCA and an increase to then-existing revenues of $73.3 million, effective June 1, 2008, which resulted in an average rate increase to IPC s customers of 10.7 percent. The IPUC s order adopted an IPUC Staff proposal to use a forecast for power supply costs that equaled the amounts in current base rates. The revenue increase was net of $16.5 million of gains from the 2007 sale of excess SO_2 emission allowances, including interest, which the IPUC ordered be applied against the PCA.

PCA Workshops: In its May 30, 2008 order approving IPC s 2008-2009 PCA, the IPUC directed IPC to set up workshops with the IPUC Staff and several of IPC s largest customers (together, the Parties) to address PCA-related issues not resolved in the PCA filing. Workshops were conducted in the fall and a settlement stipulation was filed with the IPUC and approved on January 9, 2009.

The following changes were effective as of February 1, 2009:

PCA sharing ratio the PCA allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent). The previous sharing ratio was 90/10.

LGAR the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. In the stipulation, the Parties agreed on the formula for calculating the LGAR. Based on the final rates approved by the IPUC in the 2008 general rate case and the supporting data, the current LGAR is $26.63 per MWh, effective February 1, 2009.

Use of IPC s operation plan power supply cost forecast the operation plan forecast may better match current collections with actual net power supply costs in the year they are incurred and result in smaller amounts being included in the following year s true-up rate, beginning with the 2009-2010 PCA filing.

Inclusion of third-party transmission expense transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of net power supply costs. Deviation in these costs from levels included in base rates is now reflected in PCA computations.

Adjusted distribution of base net power supply costs base net power supply costs are distributed throughout the year based upon the monthly shape of normalized revenues for purposes of the PCA deferral calculation.

Oregon: IPC has a power cost recovery mechanism in Oregon with two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows IPC to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

The APCU allows IPC 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 APCU has two components: the October Update, where each October IPC calculates its estimated normalized net power supply expenses for the following April through March test period, and the March Forecast, where each March IPC files a forecast of its expected net power supply expenses for the same test period, updated for a number of variables including the most recent stream flow data and future wholesale electric prices. On June 1 of each year, rates are adjusted to reflect costs calculated in the APCU.

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, IPC 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 IPC 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 IPC. However, a collection will occur only to the extent that it results in IPC s actual return on equity (ROE) for the year being no greater than 100 basis points below IPC s last authorized ROE. A refund will occur only to the extent that it results in IPC s actual ROE for that year being no less than 100 basis points above IPC s last authorized ROE. The PCAM rate is then added to or subtracted from the APCU rate, subject to certain statutory limitations discussed below, with new combined rates effective each June 1.

2010 APCU: On October 19, 2009, IPC filed the October Update portion of its 2010 APCU with the OPUC. The filing reflects that revenues associated with IPC s base net power supply costs would be increased by $2.6 million over the current APCU, an average 8.2 percent increase. The actual impact of the 2010 APCU will be determined once the March Forecast portion is filed in March 2010 and combined with the October Update. Final rates are expected to become effective on June 1, 2010.

22

2009 APCU: On October 23, 2008, IPC filed the October Update portion of its 2009 APCU with the OPUC. The filing, combined with supplemental testimony filed on December 1, 2008, reflects that revenues associated with IPC s base net power supply costs would be increased by $1.6 million over the previous October Update, an average 4.6 percent increase.

On March 20, 2009, IPC filed the March Forecast portion of its 2009 APCU. When combined with the October Update, the March Forecast resulted in a requested increase to Oregon revenues of 11.5 percent, or $3.9 million annually. On May 26, 2009, the OPUC approved the requested rate increase effective June 1, 2009.

2008 APCU: On May 20, 2008, the OPUC approved IPC s 2008 APCU (comprising both the October Update and the March Forecast) with the new rates effective June 1, 2008. The approved APCU resulted in a $4.8 million, or 15.7 percent, increase in Oregon revenues.

2008 PCAM: On February 27, 2009, IPC filed the true-up of its net power supply costs for the period January 1 through December 31, 2008, with the OPUC. The 2008 PCAM filing reflects a deviation of actual net power supply costs above the forecast for that period of $7.4 million. After the application of the deadband, the filing requests that $5.0 million be added to IPC s true-up balancing account and amortized sequentially after the amounts discussed below under Oregon Excess Power Cost Deferrals. A pre-hearing conference was held on April 27, 2009, to discuss the status of the case. A joint workshop and settlement conference was held July 7, 2009. As a result of the conference, IPC filed supplemental testimony on October 14, 2009, that reflects agreed upon changes to the calculation of the deferral. The revised 2008 PCAM filing now reflects a deviation of actual net power supply costs above the forecast for that period of $7.7 million and requests that $5.1 million be added to IPC s true-up balancing account and amortized sequentially.

Oregon Excess Power Cost Deferrals: The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year ($1.9 million for 2009 based on 2008 revenues). On October 6, 2008, the OPUC issued an order clarifying that the PCAM is also a deferral under the Oregon statute. The following deferrals were authorized under processes existing prior to the establishment of the PCAM.

May-December 2007 Excess Power Costs: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than normal (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon s jurisdictional share of excess power supply costs of $5.7 million. Settlement discussions were held in February 2009. As a result of those discussions, the parties to the proceeding reached a settlement and a stipulation was filed with the OPUC on April 8, 2009. In the stipulation, the parties agreed to limit the calculation of excess net power supply costs in this docket to the eight-month period from May 1 through December 31, 2007. Based on the methodology adopted by the parties to the stipulation, it was determined that IPC should be allowed to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for that period. The amount to be recovered was reduced by $0.9 million of emission allowance sales (including interest) during the same period allocated to Oregon, resulting in an approved deferral balance of $5.5 million. IPC recorded the $6.4 million deferral in the second quarter 2009 as a reduction to power cost adjustment expense. The emission allowances sales were previously deferred. The parties also agreed that the excess power supply costs from the period beginning in 2008 would be deferred pursuant to the PCAM agreement established as part of the power cost variance filing for 2008 and calculated according to the PCAM. On May 28, 2009, the OPUC issued its order adopting the stipulation.

2006-2007 Excess Power Costs: On June 30, 2009, IPC filed an application with the OPUC to begin amortizing through rates the 2006-2007 deferral of $2.0 million plus $0.4 million of accrued interest, effective September 1, 2009. The OPUC issued an order approving IPC s application on September 1, 2009. IPC expects amortization of this deferral to take approximately 16 months. The May 1 - December 31, 2007 deferral of $6.1 million (net of the emission allowance adjustment and including accrued interest) and the $5.7 million 2008 PCAM balance (including accrued interest) will be recovered sequentially following the full recovery of the 2006-2007 deferral.

Fixed Cost Adjustment Mechanism (FCA)

On March 12, 2007, the IPUC approved the implementation of a FCA mechanism pilot program for IPC s residential and small general service customers. The pilot program began on January 1, 2007, and runs through 2009. The FCA is a rate mechanism designed to remove IPC s disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. In the FCA, for each customer class, the number of customers is multiplied by a fixed cost per customer. The cost per customer is based on IPC s revenue requirement as established in a general rate case. This authorized fixed cost recovery amount is compared to the amount of fixed costs actually recovered by IPC. The amount of over- or under-recovery is then returned to or collected from customers in a subsequent rate adjustment. On October 1, 2009, IPC filed an application with the IPUC to make the FCA mechanism permanent beginning with the June 1, 2010 rate change.

On May 29, 2009, the IPUC approved a rate increase, effective June 1, 2009 through May 31, 2010, to recover $2.7 million of fixed costs under-recovered during 2008. On May 30, 2008, the IPUC approved a rate reduction, effective June 1, 2008 through May 31, 2009, to return $2.4 million of fixed costs over-recovered in 2007.

IPC deferred fixed costs of $5.0 million related to the FCA during the first nine months of 2009.

Energy Efficiency Matters

Idaho Energy Efficiency Rider (Rider): IPC s Rider is the chief funding mechanism for IPC s investment in energy efficiency and demand response programs. On May 29, 2009, the IPUC approved IPC s application to increase the Rider to 4.75 percent of base revenues, effective June 1, 2009. Based on 2008 test year revenue, IPC expects Rider revenues of $27.3 million in 2009 and $33.2 million in each of 2010 and 2011. Effective June 1, 2008, IPC began collecting 2.5 percent of base revenues, or approximately $17 million annually, under the Rider. Prior to that date, IPC collected 1.5 percent of base revenues, with funding caps for residential and irrigation customers.

Energy Efficiency Prudency Review: In the 2008 general rate case, IPC requested that the IPUC explicitly find that IPC s expenditures between 2002 and 2007 of $29 million of funds obtained from the Rider were prudently incurred and would, therefore, no longer be subject to potential disallowance. The IPUC Staff recommended that the IPUC defer a prudency determination for these expenditures until IPC was able to provide a comprehensive evaluation package of its programs and efforts. IPC contended that sufficient information had already been provided to the IPUC Staff for review.

On February 18, 2009, IPC filed a stipulation with the IPUC reflecting an agreement with the IPUC Staff on $14.3 million of the Rider funds. The IPUC Staff agreed that this portion of the Rider expenditures were prudently incurred. On March 6, 2009, the IPUC approved the stipulation, identifying $18.3 million as prudent, which included $14.3 million of Rider funding and $4.0 million of other funds.

On April 1, 2009, IPC filed an application with the IPUC seeking a prudency determination on the $14.7 million balance of Rider funds spent during 2002 through 2007. IPC has requested that this application be processed under modified procedure.

On October 5, 2009, IPC and other investor-owned electric utilities serving in Idaho engaged in an informal public workshop with the IPUC Staff to discuss how energy efficiency evaluation and prudency will be determined on a prospective basis. The IPUC Staff is expected to propose a process for energy efficiency expenditure approval as a result of the workshop.

Advanced Metering Infrastructure (AMI)

The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. In the future, the system will support enhancements to allow for time-variant rates, perform remote connects and disconnects, and collect system operations data enhancing outage management, reliability efforts and demand-side management options.

IPC filed AMI evaluation and deployment reports with the IPUC on May 1 and August 31, 2007, in compliance with an IPUC order. Consistent with the implementation plan contained in those reports, IPC entered into a number of contracts for materials and resources that allowed for the AMI implementation to commence in late 2008. IPC intends to install this technology for approximately 99 percent of its customers and is on pace to complete the installations by the end of 2011 as scheduled.

Idaho: On August 5, 2008, IPC filed an application with the IPUC requesting a CPCN for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC approved IPC s application on February 12, 2009. In its application, IPC estimated the three-year investment in AMI to be $70.9 million. In an April 7, 2009, order, the IPUC clarified that IPC can expect in the ordinary course of events, to include in rate base the prudent capital costs of deploying AMI as it is placed in service up to the capital cost commitment estimate of $70.9 million. The IPUC also clarified, as requested by IPC, that it does not anticipate that the immediate savings derived from the implementation of AMI throughout IPC s service territory will eliminate or wholly offset the increase in IPC s revenue requirement caused by the authorized depreciation period.

On March 13, 2009, IPC filed an application with the IPUC for authority to increase its rates due to the inclusion of AMI investment in rate base. The filing requested inclusion of the investments already made for the installation of AMI throughout IPC s service territory, and those investments that would be made during a June 1, 2009, through May 31, 2010 test year. IPC requested a first year revenue requirement of $11.2 million in the Idaho jurisdiction effective June 1, 2009, for service provided on or after that date. In its calculations, IPC reflected the reduction in investment and the accelerated depreciation costs related to the removal of current metering equipment, as well as changes in operating expenses that accompany the changes in plant investment.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on IPC s actual investment in AMI to date, annualized through December 31, 2009, rather than IPC s proposed test year. The IPUC also allowed IPC to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. The actual depreciation expense for fiscal year 2009 will occur over seven months totaling $6.2 million. IPC has recorded $3.5 million of this amount through September 30, 2009.

Oregon: On October 3, 2008, IPC filed an application with the OPUC requesting authority to accelerate the depreciation and recovery of existing meters in the Oregon jurisdiction over an 18-month period beginning January 2009. The OPUC approved IPC s request on December 30, 2008. IPC s AMI deployment schedule calls for the replacement of the Oregon service-territory meters around October 2010. The existing meters will be fully depreciated prior to their removal from service. The filing estimated the balance of plant in service at December 31, 2008, attributable to the existing meters to be $1.4 million. The approval of this application results in an increase of $0.8 million for 2009 in both rates and depreciation expense. This increase is partially offset by the reduced depreciation rates discussed below in Depreciation Filings. Combined, the two adjustments result in a $0.4 million net increase to annual depreciation during the period of accelerated recovery.

Depreciation Filings

On September 12, 2008, the IPUC approved a revision to IPC s depreciation rates, retroactive to August 1, 2008. The new rates are based on a settlement reached by IPC and the IPUC Staff, and result in an annual reduction of depreciation expense of $8.5 million ($7.9 million allocated to Idaho) based upon December 31, 2006, depreciable electric plant in service.

On October 3, 2008, IPC filed an application with the OPUC requesting that the new depreciation rates approved in IPC s Idaho jurisdiction be authorized for IPC s Oregon jurisdiction as well. The result for the Oregon jurisdiction would be a decrease in annual depreciation expense and rates of $0.4 million (excluding the impacts of accelerated depreciation of existing Oregon meters as discussed above in Advanced Metering Infrastructure (AMI) - Oregon). On August 18, 2009, the OPUC approved a stipulation whereby the OPUC Staff agreed not to make adjustments to the depreciation rates adopted by the IPUC. IPC committed to joint involvement of OPUC Staff prior to submitting future depreciation rates for approval in IPC s Idaho jurisdiction.

On December 3, 2009, the FERC approved IPC s request to use the IPUC- approved depreciation rates in future FERC rate filings. The new depreciation accrual rates were reflected in IPC s OATT rates beginning October 1, 2009.

Idaho Open Access Transmission Tariff (OATT) Shortfall Filing
For Idaho jurisdictional revenue requirement determinations, revenues from third parties (non-state jurisdictional) received through the OATT, referred to as revenue credits, are a direct offset to IPC s overall revenue requirement. In the last two general rate cases, IPC included an estimate of OATT revenues from third parties based on the forecasted OATT rate less a reserve. However, as discussed below in OATT , the FERC order issued on January 15, 2009 had a significant impact on actual third-party transmission revenues IPC received from June 2006 to date, resulting in the overstating of the revenue credits in the Idaho jurisdictional revenue requirement authorized by the IPUC. On July 20, 2009, IPC filed a request with the IPUC for authorization to defer $8.1 million in costs associated with the difference between the revenue credits and the amount of OATT revenues IPC has received since March 2008 and expects to receive through May 2010. Included in the filing are $4.3 million for the period March 1, 2008, through January 31, 2009, the effective period of the February 28, 2008, general rate case order and $3.8 million estimated for the period February 1, 2009, through May 31, 2010, the expected effective period of the January 30, 2009, general rate case order. IPC requested to amortize the unrecovered transmission revenues on a straight-line basis over a three-year period beginning June 1, 2010, and to receive a carrying charge on the balance until rate recovery begins. The application is proceeding under modified procedure. IPC has filed a request for rehearing of the FERC order and is taking additional measures to address the revenue shortfall. If the FERC issues are resolved in IPC s favor, IPC will reduce the deferral. On September 29, 2009, the IPUC Staff filed comments. Both parties have agreed to reduce the calculation of the total deferral from $8.1 million to $4.7 million to reflect transmission rate increases that became effective after IPC filed its application.

OATT

On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing, IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on financial and operational data IPC is required to file annually with the FERC in its Form 1. The formula rate request included a rate of return on equity of 11.25 percent. IPC s filing was opposed by several affected parties. Effective June 1, 2006, the FERC accepted IPC s proposed new rates, subject to refund pending the outcome of the hearing and settlement process.

On August 8, 2007, the FERC approved a settlement agreement by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates that were in existence before the implementation of OATT in 1996 (Legacy Agreements). This settlement reduced IPC s proposed new rates and, as a result, approximately $1.7 million collected in excess of the settlement rates between June 1, 2006, and July 31, 2007, was refunded with interest in August 2007. As part of the settlement agreement, the FERC established an authorized rate of return on equity of 10.7 percent.

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements, which would have further reduced the new transmission rates. IPC, as well as the opposing parties, appealed the Initial Decision to the FERC. If implemented, the Initial Decision would have required IPC to make additional refunds, of approximately $5.4 million (including $0.4 million of interest) for the June 1, 2006, through December 31, 2008, period. IPC previously reserved this entire amount.

On January 15, 2009, the FERC issued an Order on Initial Decision (FERC Order), which upheld the Initial Decision of the ALJ in most respects, but modified the Initial Decision in one respect that is unfavorable to IPC. The decision required IPC to reduce its transmission service rates to FERC jurisdictional customers. Furthermore, IPC was required to make refunds to FERC jurisdictional transmission customers in the total amount of $13.3 million (including $1.1 million in interest) for the period since the new rates went into effect in June 2006. Based on the FERC Order IPC reserved an additional $7.9 million (including $0.7 million in interest) in the fourth quarter of 2008, bringing the total reserve amount to $13.3 million. Prior to the FERC Order, the FERC jurisdictional transmission revenues (net of the $5 million reserve) recorded in the last seven months of 2006, all of 2007 and 2008 were $8.1 million, $13.3 million and $15.8 million, respectively. Under the FERC Order, the transmission revenues would have been $6.4 million in the last seven months of 2006, $11 million in 2007 and $12.6 million in 2008. Refunds were made on February 25, 2009.

IPC filed a request for rehearing with the FERC on February 17, 2009. IPC believes that the treatment of the Legacy Agreements conflicts with precedent. The rehearing request asserts that the FERC order is in error by: (1) requiring IPC to include the contract demands associated with the Legacy Agreements in the OATT formula rate divisor rather than crediting the revenue from the Legacy Agreements against IPC s transmission revenue requirement; (2) concluding that IPC must include the contract demands associated with the Legacy Agreements rather than the customers coincident peak demands; (3) concluding that the transmission rate contained in one or more of the Legacy Agreements was not a discounted rate; (4) failing to consider the non-monetary benefits received by IPC from the Legacy Agreements; (5) concluding that the services provided under the Legacy Agreements are firm services and therefore should be handled for rate purposes in the same manner as firm services under the OATT; and (6) failing to affirm the rate treatment that has been used for the Legacy Agreements for approximately 30 years. On March 18, 2009, the FERC issued a tolling order that effectively relieves it from acting on the request for reconsideration for an indefinite time period. IPC cannot predict when the FERC will rule on the request for rehearing or the outcome of this matter.

Amended Legacy Agreements: Subsequent to the January 15, 2009 FERC Order, IPC has sought to mitigate the resulting revenue shortfall by revising certain of the Legacy Agreements as provided for in the agreements.

On April 3, 2009, IPC notified PacifiCorp that it was terminating its provision of a portion of the services that it provides under the Restated Transmission Service Agreement (RTSA), a Legacy Agreement, effective June 12, 2009. IPC made a filing with the FERC on April 13, 2009 submitting revised rate schedule sheets. The FERC accepted the revised rate schedule sheets by letter order on May 14, 2009. On June 12, 2009 IPC submitted a filing for the purpose of replacing the terminated contract services with OATT service, effective June 13, 2009. An amended RTSA between IPC and PacifiCorp and three long term service agreements were filed to provide for the OATT service. As calculated in the filings, the estimated net transmission revenue increase for the period June 13, 2009 through June 12, 2010 is approximately $3.2 million. The FERC accepted IPC s filing, effective June 13, 2009, by letter order on July 28, 2009.

On June 19, 2009 IPC submitted a filing to increase rates under the Agreement for Interconnection and Transmission Services (ITSA) contract, another Legacy Agreement between IPC and PacifiCorp. The filing requested an increase of rates to the level paid by OATT customers for Point to Point service and an August 19, 2009 effective date. As calculated in the filing, the estimated net transmission revenue increase for the period September 1, 2009 through August 31, 2010 is approximately $3.9 million. PacifiCorp has intervened in the case and on July 10, 2009 filed a motion to suspend the case for five months and pursue settlement or go to hearing. On August 18, 2009, the FERC accepted IPC s filing and suspended it, setting it for settlement judge procedures and hearing. IPC is collecting the new rates subject to refund and has reserved the entire increase pending settlement. A settlement conference was held on October 7, 2009, and another is scheduled for November 18, 2009. Settlement discussions are ongoing.

2009 OATT: On August 28, 2009, IPC filed its informational filing with the FERC that contains the annual update of the formula rate based on the 2008 test year. The new rate included in the filing was $15.83 per kW-year, an increase of $2.02 per kW-year, or 14.6 percent. New rates were effective October 1, 2009.

2008 OATT: On August 28, 2008, IPC filed its informational filing with the FERC that contained the annual update of the formula rate based on the 2007 test year. The rate included in the filing was $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. New rates were effective October 1, 2008. IPC subsequently adjusted its rates to $13.81 per kW-year in compliance with the January 15, 2009 order.

7. COMMITMENTS AND CONTINGENCIES:

Purchase Obligations

The following items are the material changes to purchase obligations made outside of the ordinary course of business since December 31, 2008:

IPC entered into a contract to purchase coal from the Black Butte Coal Company for use at the Jim Bridger generating plant, in which IPC holds a one-third ownership. The contract is expected to total $127 million from 2010 to 2014.

In February, 2009, IPC entered into a contract with EnerNOC to implement and operate a demand response program for its commercial and industrial customers. IPC estimates it will spend approximately $12.2 million on the program during the five year term of the contract.

IPC entered into two contracts with Siemens Energy, Inc. to purchase gas and steam turbine equipment and services for the Langley Gulch power plant. IPC estimates it will spend approximately $90 million on the contracts from 2009 through 2012.

On May 7, 2009, IPC entered into an Engineering, Procurement and Construction Services Agreement (EPC Agreement) with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company for design, engineering, procurement, construction management and construction services for the Langley Gulch power plant. The total contract price to be paid by IPC under the EPC Agreement is approximately one-half of the projected $427 million total project cost for Langley Gulch from 2009 to 2012.

On June 30, 2009, IPC entered into a contract with Cargill Environmental Finance to purchase power from the Bettencourt B6 dairy anaerobic digester located near Jerome, Idaho. IPC expects the contract to total $8 million from 2009 to 2029. This agreement does not have a specified term.

In the third quarter, IPC entered into several purchased power agreements with wind and other alternate energy developers. These agreements are expected to total approximately $313 million from 2010 to 2030.

On August 12, 2009, IPC entered into a multi-year Tribal Water Rental Agreement with the Shoshone-Bannock Tribal Water Supply Bank. The agreement is expected to total approximately $10 million from 2009 to 2013.

On September 1, 2009, IPC entered into a purchased power contract with Idaho Winds, LLC. IPC s energy purchases under the contract are expected to total $105 million from 2012 to 2032.

Guarantees

IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Co., a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $63 million at September 30, 2009. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. Bridger Coal Company continually assesses the adequacy of the reclamation trust fund and recently revised their estimate of future reclamation costs. In order to ensure that the reclamation trust fund maintains adequate reserves, Bridger Coal Company will adjust coal prices by adding a per ton surcharge. As an additional safeguard, the Bridger Reclamation Trust Investment Committee has authority to compel a per-ton surcharge to ensure adequate funding levels. 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.

Legal Proceedings

From time to time IDACORP and IPC are parties to legal claims, actions and complaints in addition to those discussed below. Although they will vigorously defend against them, IDACORP and IPC are unable to predict with certainty whether or not they will ultimately be successful. However, based on the companies   evaluation, they believe that the resolution of these matters, taking into account existing reserves, will not have a material adverse effect on

IDACORP s or IPC s consolidated financial positions, results of operations or cash flows.

Reference is made to IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008, and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009, and June 30, 2009, for a discussion of all material pending legal proceedings to which IDACORP and IPC and their subsidiaries are parties. The following discussion provides a summary of material developments that occurred in those proceedings during the period covered by this report and of any new material proceedings instituted during the period covered by this report.

Western Energy Proceedings at the FERC:

Throughout this report, the term western energy situation is used to refer to the California energy crisis that occurred during 2000 and 2001, and the energy shortages, high prices and blackouts in the western United States. High prices for electricity in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds. Some of these proceedings (the western energy proceedings) remain pending before the FERC or on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

There are pending in the Ninth Circuit approximately 200 petitions for review of numerous FERC orders regarding the western energy situation, including the California refund proceeding and show cause orders with respect to contentions of market manipulation. Decisions in these appeals may have implications with respect to other pending cases, including those to which IDACORP, IPC or IE are parties. IDACORP, IPC and IE intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters, except as otherwise stated below, or estimate the impact they may have on their consolidated financial positions, results of operations or cash flows.

California Refund: This proceeding originated with an effort by agencies of the State of California and investor-owned utilities in California to obtain refunds for a portion of the spot market sales from sellers of electricity into California markets from October 2, 2000, through June 20, 2001. In April 2001, the FERC issued an order stating that it was establishing a price mitigation plan for sales in the California wholesale electricity market. The FERC s order also included the potential for directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. In July 2001, the FERC initiated the California refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. After evidentiary hearings, the FERC issued an order on refund liability on March 26, 2003, and later denied the numerous requests for rehearing. The FERC also required the California Independent System Operator (Cal ISO) to make a compliance filing calculating refund amounts. That compliance filing has been delayed on a number of occasions and has not yet been filed with the FERC.

IE and other parties petitioned the Ninth Circuit for review of the FERC s orders on California refunds. As additional FERC orders have been issued, further petitions for review have been filed by potential refund payors, including IE, potential refund recipients and governmental agencies. These cases have been consolidated before the Ninth Circuit. Since the initiation of these cases, the Ninth Circuit has convened a number of case management proceedings to organize these complex cases, while identifying and severing discrete cases that can proceed to briefing and decision and staying action on all of the other consolidated cases.

In its October 2005 decision in the first of the severed cases, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. In its August 2006 decision in the second severed case, the Ninth Circuit ruled that all transactions that occurred within the California Power Exchange (CalPX) and the Cal ISO markets were proper subjects of the refund proceeding, refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date, and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. These latter aspects of the decision exposed sellers to increased claims for potential refunds. A number of public entities filed petitions for panel rehearing in June 2007 and certain marketers filed petitions for rehearing and rehearing en banc in November 2007. Those requests were denied by the Ninth Circuit on April 6, 2009. The Ninth Circuit issued a mandate on April 15, 2009, thereby officially returning the cases to the FERC for further action consistent with the court s decision.

In 2005, the FERC established a framework for sellers wanting to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and IPC made such a cost filing but it was rejected by the FERC in March 2006. IE and IPC requested rehearing of that rejection, but, consistent with obligations established in a settlement which is described in the following paragraph, IE and IPC withdrew that request for rehearing to the extent it pertained to the disputes about the cost filing between IE and IPC and parties that had joined the settlement. On June 18, 2009 FERC issued an order with respect to the cost filings of other sellers and in that order also stated that it was not ruling on the IE and IPC request for rehearing because it had been withdrawn. On July 8, 2009 IE and IPC sought further rehearing pointing out to the FERC that the withdrawal pertained only to the parties with whom IE and IPC had settled. On June 18, 2009, in a separate order, the FERC also ruled that net refund recipients in the California refund proceeding were responsible for the costs associated with all cost filings. Most of the parties that joined the IE and IPC settlement described below were net refund recipients, but until the Cal ISO completes its refund calculations it is uncertain whether any parties who opted not to join the settlement are net refund recipients. If there are no such parties, then the requests for rehearing will be moot. On August 7, 2009 the FERC issued an order extending the time for its consideration of the IE and IPC request for rehearing. IE and IPC are unable to predict how or when the FERC might rule on their requests for rehearing, but their effect is confined to obligations of IE and IPC to the minority of market participants that opted not to join the settlement described below. Accordingly, IE and IPC believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC settling matters encompassed by the California refund proceeding, as well as other FERC proceedings and investigations relating to the western energy matters, including IE s and IPC s cost filing and refund obligation. A number of other parties, representing a small minority of potential refund claims, chose to opt out of the settlement. Under the terms of the settlement, IE and IPC assigned $24.25 million of the rights to accounts receivable from the Cal ISO and CalPX to the California Parties to pay into an escrow account for refunds to settling parties. Amounts from that escrow not used for settling parties and $1.5 million of the remaining IE and IPC receivables that are to be retained by the CalPX are available to fund, at least partially, payment of the claims of any non-settling parties if they prevail in the remaining litigation of this matter. Any excess funds remaining at the end of the case are to be returned to IE and IPC. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement. In addition, the California Parties released IE and IPC from other claims stemming from the western energy market dysfunctions. The FERC approved the Offer of Settlement on May 22, 2006.

Market Manipulation: As part of the California refund proceeding discussed above and the Pacific Northwest refund proceeding discussed below, the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered more than 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming (gaming) or other forms of proscribed market behavior in concert with another party (partnership) in violation of the Cal ISO and CalPX Tariffs. In 2004, the FERC dismissed the partnership show cause proceeding against IPC. Later in 2004, the FERC approved a settlement of the gaming proceeding without finding of wrongdoing by IPC.

The orders establishing the scope of the show cause proceedings are presently the subject of review petitions in the Ninth Circuit. In addition to the two show cause orders, on June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale markets for the time period May 1, 2000, through October 1, 2000, to enable it to review evidence of economic withholding of generation. IPC, along with more than 60 other market participants, responded to the FERC data requests. The FERC terminated its investigations as to IPC on May 12, 2004. Although California government agencies and California investor-owned utilities have appealed the FERC s termination of this investigation as to IPC and more than 30 other market participants, the claims regarding the conduct encompassed by these investigations were released by these parties in the California refund settlement discussed above. IE and IPC are unable to predict the outcome of these matters, but believe that the releases govern any potential claims that might arise and that this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

30

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding separate from the California refund proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. In late 2001, a FERC Administrative Law Judge concluded that the contracts at issue were governed by the substantially more strict *Mobile-Sierra* standard of review rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. After the Judge s recommendation was issued, the FERC reopened the proceeding to allow the submission of additional evidence directly to the FERC related to alleged manipulation of the power market by market participants. In 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit and in 2007 the Ninth Circuit issued an opinion, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit s opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency s conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources (CDWR) in the proceeding. A number of parties sought rehearing of the Ninth Circuit s decision. On April 9, 2009, the Ninth Circuit denied the petitions for rehearing and rehearing en banc. The Ninth Circuit issued a mandate on April 16, 2009, thereby officially returning the case to the FERC for further action consistent with the court s decision. On September 4, 2009 IE and IPC joined with a number of other parties in a joint petition for a writ of certiorari to the U.S. Supreme Court.

On May 22, 2009 the California Parties filed a motion with the FERC to sever the CDWR sales from the remainder of the Pacific Northwest proceedings and to consolidate the CDWR sales portion of the Pacific Northwest case with ongoing proceedings in cases that IE or IPC have settled and with a new complaint filed on May 22, 2009 by the California Attorney General against parties with whom the California Parties have not settled (Brown Complaint). On August 4, 2009, IE and IPC, along with a number of other parties, filed their opposition to the motion of the California Parties. Many other parties also filed positions in response to the motion of the California Parties. Also on August 4, 2009 the City of Tacoma, Washington and the Port of Seattle, Washington filed a motion with the FERC in connection with the California refund proceeding, the Lockyer remand pending before the FERC (involving claims of failure to file quarterly transaction reports with the FERC, from which IE and IPC previously were dismissed), the Brown Complaint and the Pacific Northwest refund remand proceeding. This latter motion asks the FERC (1) to make findings on a summary basis that the entire West-wide wholesale electricity market, including the Pacific Northwest, was affected by market manipulation and that, as a result, jurisdictional sellers rates exceeded just and reasonable levels throughout the Western energy crisis of 2000 -2001, to grant market-wide refunds to all purchasers for amounts collected in excess of a just and reasonable price and to establish procedures to determine specific refund obligations applicable to sellers or, in the alternative, (2) to institute an evidentiary hearing and establish related procedures to respond to the remand proceedings ordered by the Ninth Circuit in Port of Seattle, Washington v. FERC that would include supplemental evidence filed with the motion and consideration of claimed violations of Market Based Rate Tariffs from January 1, 2000 through June 20, 2001, thereby expanding the scope of potential refunds to a period beginning prior to December 25, 2000. On October 5, 2009, IE and IPC joined with a number of other sellers in the Pacific Northwest markets during 2000 and 2001 in filing an answer opposing the motion of the City of Tacoma and the Port of Seattle. Other parties also filed answers opposing the motion. IE and IPC intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters or estimate the impact these matters may have on their consolidated financial positions, results of operations or cash flows.

On June 26, 2008, the U.S. Supreme Court issued a decision in Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County (No. 06-1457) (Snohomish), a case regarding a FERC decision not to require re-pricing of certain long-term contracts. In Snohomish, the Supreme Court revisited and clarified the *Mobile-Sierra* doctrine in the context of fixed-rate, forward power contracts. At issue was whether, and under what circumstances, the FERC could modify the rates in such contracts on the grounds that there was a dysfunctional market at the time the contracts were executed. In its decision, the Supreme Court disagreed with many of the conclusions reached in an earlier decision by the Ninth Circuit and upheld the application of the *Mobile-Sierra* doctrine even in cases in which it is alleged that the markets were dysfunctional. The Supreme Court nonetheless directed the return of the case to the FERC to (i) consider whether the challenged rates in the case constituted an excessive burden on consumers either at the time the contracts were formed or during the term of the contracts relative to the rates that could have been obtained after elimination of the dysfunctional market and (ii) clarify whether it found the evidence inadequate to support a claim that one of the parties to a contract under consideration engaged in unlawful market manipulation that altered the playing field for the particular contract negotiations that is, whether there was a causal connection between allegedly unlawful activity and the contract rate. On November 3, 2008, the Ninth Circuit vacated its earlier decision and remanded the case to the FERC for further proceedings consistent with the Supreme Court s decision. On December 18, 2008, the FERC issued its order on remand, establishing settlement proceedings and paper hearing procedures to supplement the record and permit it to respond to the questions specified by the Supreme Court. Those proceedings are currently being held in abeyance to allow settlement efforts to proceed.

The Supreme Court s decision is expected to have general implications for contracts in the wholesale electric markets regulated by the FERC, and particular implications for forward power contracts in such markets. The Snohomish decision upholds the application of the *Mobile-Sierra* doctrine to fixed-rate, forward power contracts even in allegedly dysfunctional markets. IE and IPC have asserted the *Mobile-Sierra* doctrine in the Pacific Northwest proceeding, involving spot market contracts in an allegedly dysfunctional market.

On April 27, 2009, the U.S. Supreme Court granted a writ of certiorari in *NRG Power Marketing, LLC vs. Maine Public Utilities Commission*, a case in which neither IE nor IPC is a party. At issue is the applicability of the *Mobile-Sierra* doctrine to persons that are not parties to a contract that otherwise is governed by the doctrine. Argument is scheduled for November 3, 2009.

IDACORP, IPC and IE are unable to predict how the FERC will rule on Snohomish on remand or how the Supreme Court will decide the issues in the *NRG* case or how these decisions may affect the outcome of the Pacific Northwest proceeding.

Western Shoshone National Council: On April 10, 2006, the Western Shoshone National Council (which purports to be the governing body of the Western Shoshone Nation) and certain of its individual tribal members filed a First Amended Complaint and Demand for Jury Trial in the U.S. District Court for the District of Nevada, naming IPC and other unrelated entities as defendants. Plaintiffs allege that IPC s ownership interest in certain land, minerals, water or other resources was converted and fraudulently conveyed from lands in which the plaintiffs had historical ownership rights and Indian title dating back to the 1860 s or before.

On May 31, 2007, the U.S. District Court granted the defendants motion to dismiss stating that the plaintiffs claims are barred by the finality provision of the Indian Claims Commission Act. Plaintiffs filed a motion for reconsideration, which the District Court denied. On January 25, 2008, the District Court entered judgment in favor of IPC. Plaintiffs appealed the District Court s decision to the U.S. Court of Appeals for the Ninth Circuit. On June 4, 2009, the Ninth Circuit issued a Memorandum Opinion affirming the District Court s dismissal of the action. On June 18, 2009, plaintiffs filed with the Ninth Circuit a Petition for Rehearing En Banc, seeking rehearing of the Memorandum Opinion. On July 28, 2009, the Ninth Circuit denied the Petition for Rehearing. If pursued by plaintiffs, IPC intends to vigorously defend its position in this proceeding. IPC believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit-Bridger: IPC continues to monitor the Sierra Club and the Wyoming Outdoor Council suit against PacifiCorp filed in February 2007 in federal district court in Cheyenne, Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal-fired plant in Sweetwater County, Wyoming. IPC is not a party to this proceeding but has a one-third ownership interest in the plant. PacifiCorp owns a two-thirds interest in and is the operator of the plant. On August 24, 2009, the court granted plaintiffs motion for partial summary judgment that plaintiffs have standing to bring the action but denied the other two motions for summary judgment filed by plaintiffs and PacifiCorp. IPC is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit Boardman: On September 30, 2008, the Sierra Club and four other non-profit corporations filed a complaint against Portland General Electric Company (PGE) in the U.S. District Court for the District of Oregon alleging opacity permit limit violations at the Boardman coal-fired plant located in Morrow County, Oregon. The complaint also alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE s construction and operation of the plant. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant.

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. On September 30, 2009, the court denied most of PGE s motion to dismiss. IPC continues to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

Snake River Basin Adjudication: IPC is engaged in the Snake River Basin Adjudication (SRBA), a general stream adjudication, commenced in 1987, to define the nature and extent of water rights in the Snake River basin in Idaho, including the water rights of IPC.

On March 25, 2009, IPC and the State of Idaho (State) entered into a settlement agreement with respect to the 1984 Swan Falls Agreement and IPC s water rights under the Swan Falls Agreement, which settlement agreement is subject to certain conditions discussed below. The settlement agreement will also resolve litigation between IPC and the State relating to the Swan Falls Agreement that was filed by IPC on May 10, 2007, with the Idaho District Court for the Fifth Judicial Circuit, which has jurisdiction over SRBA matters including the Swan Falls case.

The settlement agreement resolves the pending litigation by clarifying that IPC s water rights in excess of minimum flows at its hydroelectric facilities between Milner Dam and Swan Falls Dam are subordinate to future upstream beneficial uses, including aquifer recharge. The agreement commits the State and IPC to further discussions on important water management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. It also recognizes that water management measures that enhance aquifer levels, springs and river flows, such as aquifer recharge projects, benefit both agricultural development and hydropower generation and deserve study to determine their economic potential, their impact on the environment and their impact on hydropower generation. These will be a part of the Comprehensive Aquifer Management Plan (CAMP), approved by the Idaho Water Resource Board for the Eastern Snake Plain Aquifer (ESPA), which includes limits on the amount of aquifer recharge. IPC is a member of the ESPA CAMP advisory committee and implementation committee.

On April 24, 2009, the Governor of Idaho signed into law legislation approving provisions contained in the settlement agreement. On May 6, 2009, as part of the settlement, IPC, the Governor of Idaho and the Idaho Water Resource Board executed a memorandum of agreement relating to future aquifer recharge efforts and further assurances as to limitations on the amount of aquifer recharge. IPC and the State have also filed a joint motion to the SRBA court to dismiss the Swan Falls case and enter the stipulated water right decrees set forth in the settlement agreement. At a status conference on the joint motion held on July 21, 2009, parties representing groundwater users in the Eastern Snake Plain Aquifer expressed reservations concerning some of the language proposed by IPC and the State to resolve the litigation. The language that the parties are concerned with relates to the description of the water rights in the decrees to be entered by the SRBA court as contemplated by the Settlement Agreement. Specifically the concerns relate to the language describing the subordination of the rights and its interplay with the original Swan Falls settlement document and implementing legislation. The SRBA court has ordered these matters to be briefed. Opening briefs were filed by the parties on September 4, 2009, and oral argument is scheduled to be held on November 6, 2009.

U.S. Bureau of Reclamation: IPC has filed an action in the U.S. District Court of Federal Claims in Washington, D.C. against the U.S. Bureau of Reclamation relating to a contract right for delivery of water to its hydropower projects on the Snake River to recover damages from the U.S. for the lost generation resulting from reduced flows and a prospective declaration of contractual rights so as to prevent the U.S. from continued failure to fulfill its contractual and fiduciary duties to IPC. On August 6, 2009, the court extended the discovery schedule to March 3, 2010. IPC is unable to predict the outcome of this action.

Oregon Trail Heights Fire: On August 25, 2008, a fire ignited beneath an IPC distribution line in Boise, Idaho. It was fanned by high winds and spread rapidly, resulting in one death, the destruction of 10 homes and damage or alleged fire related losses to approximately 30 others. Following the investigation, the Boise Fire Department determined that the fire was linked to a piece of line hardware on one of IPC s distribution poles and that high winds contributed to the fire and its resultant damage.

IPC has received notice of claims from a number of the homeowners and their insurers and while it has continued investigation of these claims, IPC has reached settlements with a number of the individuals or their insurers who have alleged damages resulting from the fire. IPC is insured up to policy limits against liability for claims in excess of its self-insured retention. IPC has accrued a reserve for any loss that is probable and reasonably estimable, including insurance deductibles, and believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Bureau of Land Management (BLM) Fire Claims: Effective July 1, 2009, IPC reached an agreement with the Idaho District of the BLM to settle for approximately $1 million 15 Idaho District wildland fire related claims, or potential claims, by the BLM. The fires occurred between 2005 and 2008 in the vicinity of electrical facilities operated by IPC. The BLM had not determined the exact cause of any of these fires, and in settling the claims IPC did not admit liability for the BLM s damages. With limited exceptions, this agreement settles all known or unknown claims in the BLM Idaho District, as of the effective date of the settlement. IPC has also agreed to an investigative protocol applicable to future fire claims.

8. BENEFIT PLANS:

The following table shows the components of net periodic benefit costs for the three months ended September 30 (in thousands of dollars):

	Pension Plan		Senior Management Security Plan (SMSP)		Postretirement Benefits	
	2009	2008	2009	2008	2009	2008
Service cost	$ 4,129	$ 3,730	$ 402	$ 320	$ 306	$ 314
Interest cost	6,966	6,599	714	667	892	946
Expected return on plan assets	(5,991)	(8,528)	-	-	(538)	(751)
Amortization of transition obligation	-	-	-	-	510	510
Amortization of prior service cost	162	162	58	48	(134)	(134)
Amortization of net loss	2,215	-	164	122	211	-
Net periodic benefit cost	7,481	1,963	1,338	1,157	1,247	885
Costs not recognized due to the effects of regulation [1]	(7,481)	(1,963)	-	-	-	-
Net periodic benefit cost recognized for financial reporting	$ -	$ -	$ 1,338	$ 1,157	$ 1,247	$ 885

[1] Under IPUC order, income statement recognition of pension costs has been deferred until cash contributions are made and costs are recovered through rates.

The following table shows the components of net periodic benefit costs for the nine months ended September 30 (in thousands of dollars):

	Pension Plan		Senior Management Security Plan		Postretirement Benefits	
	2009	2008	2009	2008	2009	2008
Service cost	$ 12,386	$ 11,190	$ 1,207	$ 959	$ 916	$ 865

Interest cost	20,898	19,795	2,141	2,002	2,674	2,623
Expected return on plan assets	(17,974)	(25,584)	-	-	(1,611)	(2,174)
Amortization of transition obligation	-	-	-	-	1,530	1,530
Amortization of prior service cost	488	487	174	144	(401)	(401)
Amortization of net loss	6,643	-	494	366	632	-
Net periodic benefit cost	22,441	5,888	4,016	3,471	3,740	2,443
Costs not recognized due to the effects of regulation (1)	(22,441)	(5,888)	-	-	-	-
Net periodic benefit cost recognized for financial reporting	$ -	$ -	$ 4,016	$ 3,471	$ 3,740	$ 2,443

(1) Under IPUC order, income statement recognition of pension costs have been deferred until cash contributions are made and costs are recovered through rates.

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, companies are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. The WRERA also provides for asset smoothing, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of the funding requirements. IDACORP and IPC have elected to use asset smoothing.

34

On March 31, 2009, the U.S. Department of the Treasury (Treasury) provided guidance on the selection of the corporate bond yield curve for determining plan liabilities and allows companies to choose from a range of months in selecting a yield curve, rather than requiring the use of prescribed rates. The Treasury s announcement specifically referenced 2009, but also indicated that technical guidance will be forthcoming to address future years. The revisions in the PPA, WRERA, Treasury guidance, and IRS guidance resulted in IDACORP and IPC revising the funded status as of January 1, 2009, effectively reducing or delaying the required contributions from IDACORP and IPC from what would otherwise be required, and what was previously disclosed. Based on the provisions and methodologies allowed under the PPA, WRERA, Treasury guidance and IRS guidance, IDACORP and IPC have not contributed and are not required to contribute to their pension plan in 2009, and estimated minimum required contributions will be approximately $6 million in 2010, $46 million in each of 2011 and 2012, and $41 million in 2013. IDACORP and IPC may elect to make contributions earlier than the required dates.

The IRS and Treasury have issued final regulations effective October 15, 2009 that apply to plan years beginning on or after January 1, 2010. These regulations reflect provisions added by the PPA, as amended by the WRERA. The regulations provide guidance regarding the determination of the value of plan assets and benefit liabilities for purposes of the funding requirements, regarding the use of certain funding balances and regarding benefit restrictions for certain underfunded defined benefit pension plans. These final regulations are substantially consistent with earlier guidance and IDACORP and IPC do not expect implementation to materially change existing estimates relating to pension plan contributions.

Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact funding requirements. IDACORP and IPC continue to monitor the legislative and regulatory environments for additional changes, evaluating them for their potential impact on funding requirements and strategies.

9. INVESTMENTS IN DEBT AND EQUITY SECURITIES:

Investments in debt and equity securities that are classified as available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income. IPC s available-for-sale securities are investments in broadly diversified equity index funds used to fund IPC s Senior Management Security Plan.

Investments in debt and equity securities that are classified as held-to-maturity securities are reported at amortized cost. Held-to-maturity securities are investments in debt securities for which the company has the positive intent and ability to hold the securities until maturity. These debt securities mature in 2009 and 2010. In 2009, $4.9 million of investments in debt securities previously classified as held-to-maturity were reclassified to available-for-sale and sold to facilitate the early repayment of debt, and $4.1 million of investments in available-for-sale securities were sold to fund an investment in affordable housing.

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

		September 30, 2009			December 31, 2008		
		Gross Unrealized Gain	**Gross Unrealized Loss**	**Fair Value**	**Gross Unrealized Gain**	**Gross Unrealized Loss**	**Fair Value**
Available-for-sale	IPC	$ 2,298	$ -	$ 17,584	$ -	$ -	$ 14,451
Held to Maturity	IFS	2	-	477	3	25	9,448

At the end of each reporting period, IDACORP and IPC analyze securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At September 30, 2009, no securities were in an unrealized loss position.

The following table summarizes securities that were in an unrealized loss position at December 31, 2008, but for which no other-than-temporary impairment was recognized (in thousands of dollars).

	Less than 12 months		**12 months or longer**	
	Aggregate Unrealized Loss	**Aggregate Related Fair Value**	**Aggregate Unrealized Loss**	**Aggregate Related Fair Value**
Held-to-maturity debt securities (IFS)	$ -	$ -	$ 25	$ 3,975

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

	Three months ended September 30		**Nine months ended September 30**	
	2009	**2008**	**2009**	**2008**
Proceeds from sales	$ 15	$ -	$ 9,030	$ -
Gross realized gains from sales	-	-	11	-
Gross realized losses from sales	-	-	35	-

10. FAIR VALUE MEASUREMENTS:

IDACORP and IPC have categorized their financial instruments recorded at fair value on the financial statements into a three-level fair value hierarchy based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). If the inputs used to measure the financial instruments fall within different levels of the hierarchy, the categorization is based on the lowest level input that is significant to the fair value measurement of the instrument. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of these assets and liabilities. Financial assets and liabilities are categorized based on the inputs to the valuation techniques as follows:

Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market that IDACORP and IPC have the ability to access.

Level 2: Financial assets and liabilities whose values are based on the following:

a) Quoted prices for similar assets or liabilities in active markets;

b) Quoted prices for identical or similar assets or liabilities in non-active markets;

c) Pricing models whose inputs are observable for substantially the full term of the asset or liability;

d) Pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

Level 2 inputs are based on quoted market prices adjusted for location using corroborated, observable market data and quoted prices for similar assets in non-active markets.

Level 3: Financial assets and liabilities whose values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management s own assumptions about the assumptions a market participant would use in pricing the asset or liability.

The following table presents information about IDACORP s and IPC s assets and liabilities measured at fair value on a recurring basis as of September 30, 2009 and December 31, 2008 (in thousands of dollars):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
September 30, 2009				
IDACORP				
Assets:				
Derivatives	$ 712	$ 431	$ -	$ 1,143
Money market funds	8,479	-	-	8,479
Trading securities: Equity securities	6,034	-	-	6,034
Available-for-sale securities:				
Equity securities	17,584	-	-	17,584
Liabilities:				
Derivatives	$ (523)	$ -	$ -	$ (523)
IPC				
Assets:				
Derivatives	$ 712	$ 431	$ -	$ 1,143
Money market funds	2,365	-	-	2,365
Trading securities: Equity securities	5,000	-	-	5,000
Available-for-sale securities:				
Equity securities	17,584	-	-	17,584
Liabilities:				
Derivatives	$ (523)	$ -	$ -	$ (523)
December 31, 2008				
IDACORP				
Assets:				
Derivatives	$ 652	$ -	$ -	$ 652
Money market funds	4,610	-	-	4,610
Trading securities: Equity securities	5,904	-	-	5,904
Available-for-sale securities:				
Equity securities	14,451	-	-	14,451
Liabilities:				
Derivatives	$ -	$ (2,653)	$ -	$ (2,653)

IPC								
Assets:								
Derivatives	$	652	$	-	$	-	$	652
Money market funds		1,224		-		-		1,224
Trading securities: Equity securities		4,679		-		-		4,679
Available-for-sale securities:								
Equity securities		14,451		-		-		14,451
Liabilities:								
Derivatives	$	-	$	(2,653)	$	-	$	(2,653)

IPC s derivatives are contracts entered into as part of our management of loads and resources. Electricity swaps are valued on the Intercontinental Exchange with quoted prices in an active market. Natural gas derivative and diesel derivative valuations are performed using New York Mercantile Exchange (NYMEX) pricing, adjusted for basis location, which are also quoted under NYMEX. Trading securities consists of employee-directed investments held in a Rabbi Trust and are related to an executive deferred compensation plan. Available-for-sale securities are related to the SMSP and are held in a Rabbi Trust and are actively traded money market and equity funds with quoted prices in active markets.

37

The following table presents the carrying value and estimated fair value of certain other financial instruments that were not reported at fair value on the financial statements at September 30, 2009 and December 31, 2008 (in thousands of dollars). These fair value estimates are made using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts. Cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for notes receivable and long-term debt are based upon discounted cash flow analyses.

	September 30, 2009				**December 31, 2008**			
	Carrying Amount		**Estimated Fair Value**		**Carrying Amount**		**Estimated Fair Value**	
IDACORP								
Assets:								
Notes receivable	$	3,122	$	3,122	$	5,703	$	5,726
Debt securities		476		477		-		-
Liabilities:								
Long-term debt	$	1,371,474	$	1,380,718	$	1,277,042	$	1,199,699
IPC								
Assets								
Notes receivable	$	-	$	-	$	259	$	282
Liabilities:								
Long-term debt	$	1,363,854	$	1,373,245	$	1,268,818	$	1,191,476

11. SEGMENT INFORMATION:

IDACORP s only reportable segment is utility operations, for which the primary source of revenue is the regulated operations of IPC. IPC s regulated operations include the generation, transmission, distribution, purchase and sale of electricity. This segment also includes income from Bridger Coal Company, an unconsolidated joint venture also subject to regulation.

Other operating segments are below the quantitative thresholds for reportable segments and are included in the All Other category. This category is comprised of IFS s investments in affordable housing developments and historic rehabilitation projects, Ida-West s joint venture investments in small hydroelectric generation projects, the remaining activities of energy marketer IE, which wound down its operations in 2003, and IDACORP s holding company expenses.

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

	Utility Operations	All Other	Eliminations	Consolidated Total
Three months ended September 30, 2009:				
Revenues	$ 323,128	$ 1,381	$ -	$ 324,509
Income attributable to IDACORP, Inc.	51,057	3,421	-	54,478
Total assets at September 30, 2009	3,980,757	162,265	(25,730)	4,117,292
Three months ended September 30, 2008:				
Revenues	$ 298,107	$ 1,609	$ -	$ 299,716
Income attributable to IDACORP, Inc.	47,405	4,334	-	51,739
Nine months ended September 30, 2009:				
Revenues	$ 793,675	$ 3,042	$ -	$ 796,717
Income attributable to IDACORP, Inc.	96,667	4,170	-	100,837
Nine months ended September 30, 2008:				
Revenues	$ 739,848	$ 3,534	$ -	$ 743,382
Income attributable to IDACORP, Inc.	86,404	4,565	-	90,969

12. DERIVATIVE INSTRUMENTS

Commodity Price Risk

IPC is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is commodity price risk related to IPC s ongoing utility operations providing electricity to meet the demand of its retail customers. Physical and financial forward contracts for both electricity and fuel used to produce electricity are entered into to manage the price risk associated with meeting forecasted loads. The objective of IPC s energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability and make economic use of temporary surpluses that may develop.

All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet. IPC s physical forward contracts qualify for the normal purchases and normal sales exception to derivative accounting requirements with the exception of forward contracts for the purchase of natural gas for use at IPC s natural gas generation facilities. Because of IPC s PCA mechanism, IPC records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

As of September 30, 2009, IPC had the following outstanding derivative commodity forward contracts that were entered into for the purpose of economically hedging forecasted purchases and sales:

Commodity	**Number of Units**	
Electricity purchases	604,650	MWh
Electricity sales	473,750	MWh
Natural gas	1,147,000	MMBtu
Diesel	225,564	gallons

39

The following table presents the fair values of derivatives not designated as hedging instruments recorded in the balance sheet at September 30, 2009 (in thousands of dollars):

	Asset Derivatives			Liability Derivatives		
Commodity derivatives	**Balance Sheet Location**	**Fair Value**		**Balance Sheet Location**	**Fair Value**	
Current:						
Financial swaps	Other current assets	$	2,670	Other current liabilities	$	1,969
Financial swaps	Other current liabilities		308	Other current assets		830
Forward contracts	Other current assets		431	Other current liabilities		-
Long-term:						
Financial swaps	Other assets		144	Other liabilities		133
Total		$	3,553		$	2,932

The following table presents the effect on income of derivatives not designated as hedging instruments for the three and nine months ended September 30, 2009 (in thousands of dollars):

Commodity derivatives	**Location of Gain/(Loss) Recognized in Income on Derivative**	**Amount of Gain/(Loss) Recognized in Income on Derivative**(1)	
Three months ended September 30, 2009:			
Financial swaps	Off-system sales	$	1,017
Financial swaps	Purchase power		(876)
Financial swaps	Fuel expense		(986)
Forward contracts	Fuel expense		(5,794)
Nine months ended September 30, 2009:			
Financial swaps	Off-system sales	$	3,304
Financial swaps	Purchase power		3,296
Financial swaps	Fuel expense		(986)
Forward contracts	Fuel expense		(5,794)

(1)Excludes changes in fair value of derivatives, which are recorded on the balance sheet as regulatory assets or liabilities.

IPC records changes in fair value of its derivative contracts as either regulatory assets or liabilities. Settlement gains and losses on electricity swap contracts are recorded on the income statement in off-system sales or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on both financial and physical contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives, which were immaterial for the quarter and year-to-date, are recorded in fuel inventory on the balance sheet.

Credit Risk

At September 30, 2009, IPC does not have material credit exposure from financial instruments, including derivatives. IPC monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. IPC manages these risks by establishing appropriate credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits or letters of credit from counterparties or their affiliates, as deemed necessary. The majority of IPC s contracts are under the Western Systems Power Pool agreement that provides for adequate assurances if a counterparty has debt that is downgraded to below investment grade by at least one rating agency. IPC also requires North American Energy Standards Board contracts as necessary for physical gas transactions, and International Swaps and Derivatives Association, Inc. contracts as needed for financial transactions.

Credit-Contingent Features

Certain of IPC s derivative instruments contain provisions that require IPC s unsecured debt to maintain an investment grade credit rating from each of the major credit rating agencies. If IPC s unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on September 30, 2009, is $2.9 million. IPC has posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on September 30, 2009, IPC could have been required to post $0.5 million of cash collateral to its counterparties.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of IDACORP, Inc.
Boise, Idaho

We have reviewed the accompanying condensed consolidated balance sheet of IDACORP, Inc. and subsidiaries (the Company) as of September 30, 2009, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2009 and 2008, and of cash flows for the nine-month periods ended September 30, 2009 and 2008. These interim financial statements are the responsibility of the Company s management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of IDACORP, Inc. and subsidiaries as of December 31, 2008, and the related consolidated statements of income, comprehensive income, shareholders equity, and cash flows for the year then ended prior to retrospective adjustment for the adoption of accounting guidance for noncontrolling interests in consolidated financial statements (not presented herein); and in our report dated February 25, 2009, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of guidance for accounting for uncertainty in income taxes and employers accounting for defined benefit pension and other postretirement plans. We also audited the adjustments described in Note 1 that were applied to retrospectively adjust the December 31, 2008, consolidated balance sheet of IDACORP, Inc. and subsidiaries (not presented herein). In our opinion, such adjustments are appropriate and have been properly applied to the previously issued consolidated balance sheet in deriving the accompanying retrospectively adjusted consolidated balance sheet as of December 31, 2008.

/s/*DELOITTE & TOUCHE LLP*

Boise, Idaho
October 29, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Idaho Power Company
Boise, Idaho

We have reviewed the accompanying condensed consolidated balance sheet and statement of capitalization of Idaho Power Company and subsidiary (the Company) as of September 30, 2009, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2009 and 2008, and of cash flows for the nine-month periods ended September 30, 2009 and 2008. These interim financial statements are the responsibility of the Company s management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and statement of capitalization of Idaho Power Company and subsidiary as of December 31, 2008, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for the year then ended (not presented herein); and in our report dated February 25, 2009, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of guidance for accounting for uncertainty in income taxes and employers accounting for defined benefit pension and other postretirement plans. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet and statement of capitalization as of December 31, 2008, is fairly stated, in all material respects, in relation to the consolidated balance sheet and statement of capitalization from which it has been derived.

/s/*DELOITTE & TOUCHE LLP*

Boise, Idaho
October 29, 2009

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

INTRODUCTION:

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

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

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

IDACORP s other subsidiaries include:

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

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

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

While reading the MD&A, please refer to the accompanying Condensed Consolidated Financial Statements of IDACORP and IPC. This discussion updates the MD&A included in the Annual Report on Form 10-K for the year ended December 31, 2008, and the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009, and should be read in conjunction with the discussions in those reports.

FORWARD-LOOKING INFORMATION:

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

The effect of regulatory decisions by the Idaho Public Utilities Commission, the Oregon Public Utility Commission and the Federal Energy Regulatory Commission affecting our ability to recover costs and/or earn a reasonable rate of return including, but not limited to, the disallowance of costs that have been deferred;

Changes in and compliance with state and federal laws, policies and regulations, including new interpretations by oversight bodies, which include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission and the Oregon Public Utility Commission, of existing policies and regulations that affect the cost of compliance, investigations and audits, penalties and costs of remediation that may or may not be recoverable through rates;

Changes in tax laws or related regulations or new interpretations of applicable law by the Internal Revenue Service or other taxing jurisdictions;

Litigation and regulatory proceedings, including those resulting from the energy situation in the western United States, and penalties and settlements that influence business and profitability;

Changes in and compliance with laws, regulations and policies including changes in law and compliance with environmental, natural resources, endangered species and safety laws, regulations and policies and the adoption of laws and regulations addressing greenhouse gas emissions, global climate change, and energy policies;

Global climate change and regional weather variations affecting customer demand and hydroelectric generation;

Over-appropriation of surface and groundwater in the Snake River Basin resulting in reduced generation at hydroelectric facilities;

Construction of power generation, transmission and distribution facilities, including an inability to obtain required governmental permits and approvals, rights-of-way and siting, and risks related to contracting, construction and start-up;

Operation of power generating facilities including performance below expected levels, breakdown or failure of equipment, availability of transmission and fuel supply;

Changes in operating expenses and capital expenditures, including costs and availability of materials, fuel and commodities;

Blackouts or other disruptions of Idaho Power Company s transmission system or the western interconnected transmission system;

Population growth rates and other demographic patterns;

Market prices and demand for energy, including structural market changes;

Increases in uncollectible customer receivables;

Fluctuations in sources and uses of cash;

Results of financing efforts, including the ability to obtain financing or refinance existing debt when necessary or on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets and other economic conditions;

Actions by credit rating agencies, including changes in rating criteria and new interpretations of existing criteria;

Changes in interest rates or rates of inflation;

Performance of the stock market, interest rates, credit spreads and other financial market conditions, as well as changes in government regulations, which affect the amount and timing of required contributions to pension plans and the reported costs of providing pension and other postretirement benefits;

Increases in health care costs and the resulting effect on medical benefits paid for employees;

Increasing costs of insurance, changes in coverage terms and the ability to obtain insurance;

Homeland security, acts of war or terrorism;

Natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind and fire;

Adoption of or changes in critical accounting policies or estimates; and

New accounting or Securities and Exchange Commission requirements, or new interpretation or application of existing requirements.

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

EXECUTIVE OVERVIEW:

Third quarter and Year-to-date 2009 Financial Results

A summary of net income attributable to IDACORP, Inc. and earnings per diluted share is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2009	**2008**	**2009**	**2008**
Net income attributable to IDACORP, Inc.	$ 54,478	$ 51,739	$ 100,837	$ 90,969
Average outstanding shares diluted (000s)	47,141	45,246	46,999	45,149
Earnings per diluted share	$ 1.16	$ 1.14	$ 2.15	$ 2.02

The following table presents a reconciliation of net income attributable to IDACORP, Inc. for the three and nine months ended September 30, 2008 to September 30, 2009 (in millions):

	Three months ended		Nine months ended	
September 30, 2008		**$ 51.7**		**$ 91.0**
Change in IPC net income before taxes:				
Rate and other regulatory changes, net of PCA	$ 4.3		$ 20.5	
Reduced sales volumes, net of FCA deferral	(5.5)		(20.7)	
Oregon 2007 excess power cost deferral in 2009	-		6.4	
Decrease in transmission revenue	(1.3)		(4.2)	
Reduced effective income tax rate	3.8		7.3	
Other, including tax impacts of listed items	2.4		1.0	
Total increase in IPC net income		3.7		10.3
Other net decreases (net of tax)		(0.9)		(0.5)
September 30, 2009		**$ 54.5**		**$ 100.8**

Changes to the Idaho power cost adjustment (PCA) mechanism and changes to base rates positively impacted net income. These changes were partially offset by the increased depreciation expense related to the Advanced Metering Infrastructure (AMI) project and increased net power supply costs. Also offsetting the changes was the effect of Idaho Public Utilities Commission (IPUC) orders that revised the allocation method for base net power supply costs in the PCA calculation over the year. The allocation method did not affect the total amount of base net power supply costs used to calculate the PCA deferral, but did affect the quarters in which the costs were allocated. This change reduced earnings by approximately $4.2 million and $1.6 million (net of tax) for the quarter and year-to-date, respectively, compared to 2008.

IPC s retail customer sales volumes decreased four percent for the quarter and five percent year-to-date, primarily due to weather fluctuations. To a lesser extent economic factors and energy efficiency contributed to the reduction in sales volume. Partially offsetting the volume decreases is the Fixed Cost Adjustment (FCA) Mechanism, which mitigates the impact of changes in sales volumes from levels included in base rates.

Increasing the 2009 year-to-date earnings is a May 2009 Oregon Public Utility Commission (OPUC) stipulation allowing the deferral for future recovery of $6.4 million of excess power supply costs incurred in 2007, the effect of which was recorded in the second quarter of 2009. This deferral is discussed in more detail in REGULATORY MATTERS Oregon May-December 2007 Excess Power Costs.

Transmission revenue decreased due to a decrease in the open access transmission tariff (OATT) rates.

IPC s 2009 effective income tax rate decreased primarily due to an examination settlement, state bonus depreciation and timing and amount of other regulatory flow-through tax adjustments.

Capital Requirements

IPC has several major projects in development. These projects are summarized here and are discussed further in LIQUIDITY AND CAPITAL RESOURCES Capital Requirements Major Projects.

Langley Gulch power plant (2012 baseload resource): On September 1, 2009, the IPUC issued an order granting IPC s March 6, 2009, request for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant (Langley Gulch). The order also provided for cost recovery and ratemaking assurances requested by IPC related to Langley Gulch. Langley Gulch will be a natural gas-fired combined cycle combustion turbine generating plant with a summer nameplate capacity of approximately 300 MWs and a winter capacity of approximately 330 MWs. The plant will be constructed at an estimated cost of $427 million near New Plymouth, Idaho commencing in summer 2010, and is anticipated to achieve commercial operation by November 1, 2012. The plant will connect to IPC s existing grid.

Gateway West transmission project: IPC and PacifiCorp are jointly exploring Gateway West, a project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and Hemingway, a substation located in the vicinity of Melba and Murphy, Idaho near Boise. The estimated cost for IPC s share of the project is between $500 million and $600 million. The lines will provide transmission service for existing network and native load customers and their forecasted growth and provide for existing third-party transmission service requests. This project is intended to relieve existing congestion by increasing transmission capacity and to improve reliability to comply with reliability regulations. Initial phases of the project could be completed by 2014.

Boardman-Hemingway transmission project: IPC is also exploring alternatives for the construction of a 500-kV line between southwestern Idaho at the Hemingway substation and the Northwest at the Boardman substation. IPC estimates construction costs of $600 million and expects to seek partners for up to 50 percent of the project when construction commences. The Boardman-Hemingway Line will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third-party transmission service requests. This project is intended to relieve existing congestion by increasing transmission capacity and to improve reliability to comply with reliability regulations. IPC estimates the project will be completed in 2015.

Liquidity

Pension Plan: Provisions of the Pension Protection Act (PPA), relief provisions of the Worker, Retiree, and Employer Recovery Act (WRERA), U.S. Treasury Department (Treasury) guidance, and IRS guidance require that if a company does not meet minimum funding levels, the company must make additional contributions to improve the funded status of the plan. The funded status of IPC s pension plan at January 1, 2009, was above the minimum required funding levels as revised by the PPA, WRERA, Treasury guidance and IRS guidance. Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, IDACORP and IPC have not contributed and are not required to contribute to the pension plan in 2009, and estimated minimum required contributions will be approximately $6 million in 2010, $46 million in both 2011 and 2012, and $41 million in 2013.

Regulatory Matters

IPC has a number of regulatory matters in process or recently completed. These matters are summarized here and are discussed in more detail in REGULATORY MATTERS later in the MD&A.

Idaho 2009 General Rate Case Notice of Intent to File: On August 28, 2009, IPC filed with the IPUC a notice of intent to file a general rate case on or after October 28, 2009. The notice of intent provides IPC with a 60-day window, beginning October 28, 2009, in which it is permitted to file a new general rate case. Since filing the notice of intent, IPC has reached an agreement in principle with its customer groups and IPUC Staff regarding a number of rate issues that may avoid the anticipated general rate case filing. This agreement will be memorialized in a formal settlement stipulation and together with supporting testimony will be filed in early November with the IPUC for approval.

Oregon 2009 General Rate Case: On July 31, 2009, IPC filed an application with the OPUC requesting an average rate increase of approximately 22.6 percent, or $7.3 million annually. The application included a requested return on equity of 11.25 percent and an overall rate of return of 8.68 percent with equity at 49.8 percent of total capitalization. Oregon jurisdictional rate base included in the application is $110.8 million.

IPC filed its case based upon a 2009 test year. Based on the application of the full nine-month statutory suspension period, the new rates would become effective May 31, 2010. IPC is unable to predict what relief the OPUC will grant.

Oregon 2010 Annual Power Cost Update: On October 19, 2009, IPC filed the October Update portion of its 2010 annual power cost update (APCU). The filing reflects that revenues associated with IPC s base net power supply costs would be increased by $2.6 million over the previous October Update, an average 8.2 percent increase. The actual impact of the 2010 APCU will be determined once the March Forecast portion is filed in March 2010 and combined with the October Update. Final rates are expected to become effective on June 1, 2010.

Oregon Excess Power Cost Deferrals May-December 2007 Excess Power Costs: On May 28, 2009, the OPUC adopted a stipulation allowing IPC to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for the period May 1 through December 31, 2007. IPC recorded this deferral in the second quarter of 2009. The amount to be recovered was reduced by $0.9 million of emission allowance sales previously deferred, resulting in an approved deferral balance of $5.5 million.

Idaho and Oregon Rate Orders: IPC received five additional rate orders from the IPUC and the OPUC at the end of May 2009. The IPUC rate orders are for the Fixed Cost Adjustment mechanism, Idaho Energy Efficiency Rider, Advanced Metering Infrastructure (AMI), and PCA, and the OPUC rate order is for the Annual Power Cost Update. Each of these orders increases rates, but only the AMI order, relating to the installation of new meters, increases IPC s rate base.

Deferred Pension Expense: On October 20, 2009, IPC filed an application with the IPUC requesting the implementation of a pension recovery method for cash contributions made to the pension plan.

Idaho OATT Shortfall Filing: On July 20, 2009, IPC filed a request with the IPUC for authorization to defer $8.1 million associated with shortfalls in the amount of OATT revenues that IPC will receive between March 2008 and May 2010. On September 29, 2009, the IPUC Staff filed comments. Both parties have agreed to reduce the calculation of the total deferral from $8.1 million to $4.7 million to reflect transmission rate increases that became effective after IPC filed its application.

OATT Amended Legacy Agreements: In April and June 2009 IPC submitted filings to the FERC to increase rates under agreements IPC has with PacifiCorp. The revised agreements would increase annual transmission revenues approximately $7.1 million. On August 18, 2009, the FERC accepted one of IPC s filings for a net transmission revenue increase of $3.2 million and suspended it, setting it for settlement judge procedures and hearing. A settlement conference was held on October 7, 2009 and another is scheduled for November 18, 2009 with settlement discussions ongoing. IPC is collecting the new rates subject to refund and has reserved the entire increase pending settlement.

Integrated Resource Plan (IRP): IPC is currently preparing the 2009 IRP, which it expects to file in December 2009.

Environmental Issues

Climate Change: Climate change regulations are expected to have major implications for IPC and the energy industry. On September 17, 2009, IDACORP s and IPC s Board of Directors approved guidelines that established a goal to reduce the carbon dioxide (CO_2) emission intensity of IPC s utility operations. The guidelines are intended to further prepare IPC for potential legislative and/or regulatory restrictions on greenhouse gas (GHG) emissions while minimizing the costs of complying with such restrictions on IPC s customers. These issues are discussed in more detail in LEGAL AND ENVIRONMENTAL ISSUES Environmental Issues.

Idaho Water Management Issues: Power generation at the IPC hydroelectric power plants on the Snake River depends on the state water rights held by IPC and the long-term sustainability of the Snake River, tributary spring flows and the Eastern Snake Plain Aquifer that is connected to the Snake River. IPC continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at IPC s hydroelectric projects on the Snake River. On March 25, 2009, IPC and the State of Idaho entered into a settlement agreement with respect to the 1984 Swan Falls Agreement and IPC s water rights under the Swan Falls Agreement, which settlement agreement is subject to certain conditions. The settlement agreement will also resolve litigation between IPC and the State of Idaho relating to the Swan Falls Agreement that was filed by IPC on May 10, 2007, with the Idaho District Court for the Fifth Judicial Circuit, which has jurisdiction over Snake River Basin Adjudication (SRBA) matters. Settlement is pending approval by the court. For a further discussion of water management issues see LEGAL AND ENVIRONMENTAL ISSUES Environmental Issues Idaho Water Management Issues.

Other Issues

American Recovery and Reinvestment Act of 2009: The American Recovery and Reinvestment Act of 2009 (ARRA), enacted on February 17, 2009, includes tax and appropriation benefits to the utility industry. IPC submitted a grant application to the Department of Energy (DOE) on August 6, 2009, requesting matching funds for the $47 million of currently budgeted project funds IPC would invest towards the Smart Grid as well as incremental projects that would be funded if awarded a DOE matching grant. On October 27, 2009, IPC received notice that its application was selected. IPC continues to evaluate additional opportunities under ARRA.

2009 Operating and Financial Metrics Outlook

The outlook for key operating and financial metrics for 2009 is:

	2009 Estimates	
	Current	**Previous**
IPC Operation & Maintenance Expense (Millions)	No change	$280 - $290
IPC Capital Expenditures (Millions)(1)	$255-$270	$220 - $230
IPC Hydroelectric Generation (Million MWh) (2)	8.0-8.5	7.5 - 8.5
Non-regulated Subsidiary Earnings and Holding Company Expenses (Millions)	No change	$0.0 - $3.0
Effective Tax Rates:		
IPC	No change	26% - 31%
Consolidated - IDACORP	No change	19% - 24%

(1) The revised range of capital expenditures reflects the 2009 estimate for Langley Gulch power plant construction expenditures of $50 million to $55 million, offset by lower estimated ongoing capital expenditures. For the three-year period, 2009-2011, IPC expects to spend approximately $975 million to $1 billion. This amount includes Langley Gulch power plant and expenditures for the siting and permitting of major transmission expansions for Boardman to Hemingway transmission line, Gateway West transmission project, and the Hemingway-Bowmont transmission line and the Hemingway Station.

(2) The range of estimated hydroelectric generation includes actual generation through September and estimated ranges of generation for the reminder of the year. Year-to-date performance reflects the impact of above normal precipitation and higher reservoir storage releases.

RESULTS OF OPERATIONS:

This section of the MD&A takes a closer look at the significant factors that affected IDACORP s and IPC s earnings during the three and nine months ended September 30, 2009. In this analysis, the results for 2009 are compared to the same periods in 2008.

The following table presents net income (losses) for IDACORP and its subsidiaries:

	Three months ended September 30,		Nine months ended September 30,	
	2009	**2008**	**2009**	**2008**
IPC Utility operations	$ 51,057	$ 47,405	$ 96,667	$ 86,404
IDACORP Financial Services	245	710	574	2,212
Ida-West Energy	1,208	1,208	2,780	2,171
IDACORP Energy	(125)	(55)	(176)	(78)
Holding company	2,093	2,471	992	260
Net income attributable to IDACORP, Inc.	$ 54,478	$ 51,739	$ 100,837	$ 90,969
Average common shares outstanding (diluted)	47,141	45,246	46,999	45,149
Earnings per diluted share	$ 1.16	$ 1.14	$ 2.15	$ 2.02

Utility Operations

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

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

In accordance with IPC s risk management policy, IPC made forward purchases of energy for delivery in the third quarter of 2009. Most of the purchases were identified and made months in advance when market prices were higher. Reduced demand due to the economic decline and improved generating conditions caused regional energy market prices to drop and IPC to have additional surplus energy available for sale off-system into that lower price energy market. As a result, third quarter 2009 purchased power cost per MWh is nearly twice the off-system sales revenue per MWh and 68 percent higher year-to-date.

Hydroelectric generation in the first nine months of 2009 was much improved over 2008, due to a combination of above normal precipitation and higher reservoir storage releases. Hydroelectric generation was 103 percent and 113 percent of the 30-year average for the quarter and year-to-date, respectively.
The following table presents IPC s power supply for the three and nine months ended September 30:

	MWh Hydroelectric Generation	**Thermal Generation**	**Total System Generation**	**Purchased Power**	**Total**
Three months ended:					
September 30, 2009	2,013	2,116	4,129	1,183	5,312
September 30, 2008	1,827	2,183	4,010	1,200	5,210
Nine months ended:					
September 30, 2009	6,574	5,203	11,777	2,383	14,160
September 30, 2008	5,566	5,555	11,121	2,855	13,976

As of October 22, 2009, reservoir levels in selected federal reservoirs upstream of Brownlee were at 135 percent of average. The observed April through July Brownlee reservoir inflow was 5.6 million acre-feet (maf), or 89 percent of the Northwest River Forecast Center (NWRFC) average, an increase over the 2008 April through July inflow of 4.4 maf, which was 70 percent of average. With current and forecasted stream flow conditions, IPC expects to generate between 8.0 and 8.5 million MWh from its hydroelectric facilities in 2009, compared to 6.9 million MWh in 2008.

In August 2009, IPC entered into a five year lease with the Shoshone Bannock Tribal Water Supply Bank for 45,716 acre-feet of American Falls storage water. The scheduling of the annual releases of the leased water will be at IPC s discretion. IPC plans to take the annual water releases prior to October 12 of each year during the term of the lease. This action was taken in part to offset the impact of drought and changing water use patterns in southern Idaho and increase IPC s ability to meet mid-summer electricity demands with lower cost hydroelectric generation. Acquiring water through lease also helps IPC improve water quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the Hells Canyon Complex. IPC includes these costs in its annual PCA filing. IPC is continuing to negotiate additional water leases.

IPC s system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand established on June 30, 2008 is 3,214 MW. During this and other similar heavy load periods IPC s system is fully committed to serve loads and meet required operating reserves. The all-time winter peak demand is 2,464 MW, set on January 24, 2008.

General business revenue: The following tables present IPC s general business revenues, MWh sales, number of customers and Boise, Idaho weather conditions for the three and nine months ended September 30:

	Three months ended September 30, 2009	2008	Nine months ended September 30, 2009	2008
Revenue				
Residential	$ 104,040	$ 90,473	$ 288,243	$ 259,781
Commercial	68,195	59,615	173,152	151,624
Industrial	39,812	34,187	104,164	90,124
Irrigation	68,907	62,364	105,584	101,171
Deferred revenue related to Hells Canyon relicensing AFUDC	(3,278)	-	(7,325)	-
Total	$ 277,676	$ 246,639	$ 663,818	$ 602,700
MWh				
Residential	1,267	1,245	3,850	3,931
Commercial	1,043	1,068	2,893	2,993
Industrial	806	846	2,342	2,523
Irrigation	1,023	1,139	1,589	1,836
Total	4,139	4,298	10,674	11,283
Customers (average)				
Residential	405,355	403,015	404,785	402,035
Commercial	64,105	63,701	64,099	63,317
Industrial	128	121	126	121
Irrigation	18,855	18,533	18,729	18,353
Total	488,443	485,370	487,739	483,826
Customers (period end)				
Residential			405,481	403,309
Commercial			64,181	63,782
Industrial			128	122
Irrigation			18,845	18,547
Total			488,635	485,760

	Three months ended		Nine months ended

	September 30,				**September 30,**		
	2009	**2008**	**Normal**		**2009**	**2008**	**Normal**
Heating degree-days	54	56	137		3,227	3,557	3,478
Cooling degree-days	980	841	646		1,188	1,054	802
Precipitation (inches)	1.88	1.22	1.45		7.45	5.36	8.67

Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity. They indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average of the daily high and low 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.

As part of its February 1, 2009, general rate case order, the IPUC allowed IPC to recover allowance for funds used during construction (AFUDC) for the Hells Canyon Complex relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. IPC expects to collect approximately $10.6 million annually, but will defer revenue recognition of the amounts collected until the license is issued and the asset is placed in service. This deferral offset revenues by approximately $3.3 million for the quarter and $7.3 million year-to-date.

General business revenue increased $31.0 million for the quarter and $61.1 million year-to-date as compared to the same periods in 2008. This increase is primarily attributable to the effects of rate changes and was partially offset by a decrease in customer usage:

Rates: Rate changes positively impacted general business revenue $38.8 million for the quarter and $91.6 million year-to-date. This reflects PCA rate increases of $24.3 million and $59.1 million for the quarter and year-to-date, respectively, and increases in retail base rates, discussed in REGULATORY MATTERS, of $14.5 million and $32.5 million for the quarter and year-to-date, respectively.

Also impacting rates is a new tiered rate structure for residential and small commercial customers implemented as part of the February 1, 2009, general rate case. The table below presents the residential rates by tier.

Idaho Residential Rate Structure

February 1, 2008	**Summer**	**Non-Summer**	**February 1, 2009**	**Summer**	**Non-Summer**
0-300 kWh	5.6973 cents	5.6973 cents	0-800 kWh	5.9750 cents	5.5792 cents
Above 300 kWh	6.4125 cents	5.6973 cents	801-2,000 kWh	7.2798 cents	6.1991 cents
			Above 2,000 kWh	8.7358 cents	7.1290 cents

Customers: Growth in customer count in IPC s service territory increased revenue $3.4 million for the quarter and $8.2 million year-to-date. Average customer count by class increased from the prior period as follows:

Customer Class	**Quarter Change %**	**Year-to-date Change %**
Residential	0.6	0.7
Commercial	0.6	1.2
Industrial	5.8	3.8
Irrigation	1.7	2.0
Overall weighted total	0.6	0.8

Usage: Lower usage decreased general business revenue $10.9 million for the quarter and $38.3 million year-to-date. Irrigation usage decreased ten percent for the quarter and 13 percent year-to-date due to increased precipitation. Precipitation was 54 percent higher than the third quarter last year and 39 percent higher for the year-to-date. Commercial and industrial usage also declined due to a weaker economy and increased energy efficiency. The impact of this reduction is partially mitigated by the Load Growth Adjustment Rate (LGAR) and FCA Mechanisms, both of which were put in place to manage the impact of changes in sales volumes from levels included in base rates.

Off-system sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The following table presents IPC s off-system sales for the three and nine months ended September 30:

	Three months ended		**Nine months ended**	
	September 30, 2009	**2008**	**September 30, 2009**	**2008**
Revenue	$ 23,691	$ 34,637	$ 78,888	$ 93,640
MWh sold	734	498	2,406	1,520
Revenue per MWh	$ 32.28	$ 69.55	$ 32.79	$ 61.61

53

Off-system sales revenue decreased $10.9 million, or 32 percent, for the quarter and $14.8 million, or 16 percent year-to-date. Although improved hydroelectric generating conditions and lower system load increased the amount of electricity available for sale, prices for wholesale power in the Northwest were much lower than last year due to lower energy commodity prices and an abundance of energy in the region.

Other revenues: The table below presents the components of other revenues for the three and nine months ended September 30:

	Three months ended September 30,				**Nine months ended September 30,**			
	2009		**2008**		**2009**		**2008**	
Transmission services and property rental	$	9,559	$	10,875	$	26,036	$	30,259
Energy efficiency		12,202		5,956		24,933		13,249
Total	$	21,761	$	16,831	$	50,969	$	43,508

The decrease in transmission services and property rental reflects new OATT rates implemented in January 2009. For further discussion, please refer to REGULATORY MATTERS Federal Regulatory Matters OATT.

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 IPC has collected more than it has spent and an asset balance indicates that IPC has spent more than collected. For the quarter and the year-to-date, IPC has increased its energy efficiency program expenses and matching revenues $6.2 million and $11.7 million, respectively, and on September 30, 2009, IPC s rider balance was a regulatory asset of $10.2 million.

Purchased power: The following table presents IPC s purchased power expenses and volumes for the three and nine months ended September 30:

Three months ended September 30,		**Nine months ended September 30,**	
2009	**2008**	**2009**	**2008**

Purchased power expense	$	73,483	$	79,513	$	131,370	$	174,900
MWh purchased		1,184		1,200		2,383		2,855
Cost per MWh purchased	$	62.06	$	66.26	$	55.13	$	61.26

Purchased power expense decreased $6.0 million, or eight percent, for the quarter and $43.5 million, or 25 percent year-to-date. Lower system loads and more favorable hydroelectric generating conditions decreased the amount of purchased power IPC needed to serve loads.

Fuel expense: The following table presents IPC s fuel expenses and generation at its thermal generating plants for the three and nine months ended September 30:

	Three months ended September 30,				**Nine months ended September 30,**			
	2009		**2008**		**2009**		**2008**	
Fuel expense	$	49,530	$	46,467	$	113,138	$	112,385
Thermal MWh generated		2,116		2,183		5,203		5,555
Cost per MWh	$	23.41	$	21.29	$	21.74	$	20.23

Fuel expense increased $3.1 million, or seven percent, for the quarter and remained nearly even for the year-to-date. For the quarter, IPC increased generation at its gas-fired turbine plants. For the year-to-date, lower thermal MWh generated due to lower system loads was mostly offset by increased costs at the Bridger plant due to the continued transition to underground mining.

PCA: PCA expense represents the effects of the Idaho PCA and Oregon power cost adjustment mechanism (PCAM) deferrals of net power supply costs (fuel, purchased power and third party transmission expense less off-system sales). These mechanisms are discussed in more detail below in REGULATORY MATTERS Deferred Net Power Supply Costs.

The following table presents the components of the PCA for the three and nine months ended September 30:

	Three months ended September 30,				Nine months ended September 30,			
	2009		**2008**		**2009**		**2008**	
Idaho power supply cost deferral	$	(34,501)	$	(55,469)	$	(36,505)	$	(80,638)
Oregon 2007 excess power cost order		-		-		(6,358)		-
Amortization of prior year authorized balances		36,115		35,364		87,099		41,960
Total power cost adjustment	$	1,614	$	(20,105)	$	44,236	$	(38,678)

The PCA and PCAM increased expenses $21.7 million for the quarter and $82.9 million year-to-date, due to lower deferrals of power supply costs and higher amortization of previously deferred power supply costs. In addition, an order from the OPUC that allows IPC to defer for future recovery $6.4 million of costs incurred in 2007 was recorded in the second quarter of 2009, impacting the year-to-date.

Effect of the Distribution of Base Net Power Supply Costs on Quarterly Results:

On May 30, 2008, the IPUC approved changes from a seasonal distribution to an even monthly distribution of the base net power supply costs included in the 2007 general rate case for use in the calculation of the Idaho PCA deferral. The adopted allocation was effective retroactive to March 1, 2008. Effective February 1, 2009, the monthly allocation method was changed again, to a method based on monthly general business sales volumes.

While the distribution methodology used does not affect the total amount of base net power supply costs used to calculate the PCA deferral for a full year, it does affect the quarters in which they are allocated and thus impacts quarterly results.

The following table reconciles base net power supply costs used in the PCA mechanism in 2008 and 2009 and shows the estimated after-tax earnings impact of the change in allocation method. The fourth quarter 2009 amounts are projections based on the mechanism currently in effect (in millions of dollars):

	Third Quarter	September 30 Year-to-date	Fourth Quarter	Total
Base net power supply costs 2008	$ 31.2	$ 82.4	$ 31.2	$ 113.6
Change in monthly allocation method	7.6	2.9	(2.9)	-
Increase due to base changes from rate cases	8.7	31.2	6.3	37.5
Base net power supply costs 2009	$ 47.5	$ 116.5	$ 34.6	$ 151.1
Estimated impact on net income of the changes in allocation methods (2009 vs. 2008), after jurisdictionalization	$ (4.2)	$ (1.6)	$ 1.6	$ -

Other operations and maintenance expenses: Other operations and maintenance expense decreased $2 million for the quarter and $1 million year-to-date. The quarter decrease was primarily attributable to a reduction in outside services due to cost containment measures.

Year-to-date other operations and maintenance expense decreased principally due to a $6.1 million reduction in outside services and other cost containment measures, partially offset by a $5.6 million increase in labor-related expenses, and a $1.4 million increase in charges for uncollectible accounts.

The $1.4 million year-to-date increase in charges for uncollectible accounts is due to the deterioration of the economy across IPC s service area. IPC s $84 million customer accounts receivable balance includes $54.8 million related to residential, commercial and industrial retail customers accounts. Receivables for these customer classes increased 8.3 percent, while the allowance for uncollectible accounts reserve for these customer classes increased 12.3 percent as compared to December 31, 2008, corresponding to the increase in write-off activity for these customer classes.

Non-utility Operations

IFS: IFS s net income decreased $0.5 million for the quarter and $1.6 million year-to-date compared to the same periods of 2008. The reductions are principally due to lower tax benefits caused by the continued aging of existing investments. IFS s income is derived principally from the generation of federal income tax credits and accelerated tax depreciation benefits related to its investments in affordable housing and historic rehabilitation developments. IFS made $12.1 million in new investments and generated tax credits of $6.1 million through September 30, 2009.

Income Taxes

In accordance with interim reporting requirements, IDACORP and IPC use an estimated annual effective tax rate for computing their provisions for income taxes. IDACORP s effective tax rate for the nine months ended September 30, 2009, was 20.3 percent, compared to 23.8 percent for the nine months ended September 30, 2008. IPC s effective tax rate for the nine months ended September 30, 2009, was 27.2 percent, compared to 32.9 percent for the nine months ended September 30, 2008. The decrease in the 2009 estimated annual effective tax rates from 2008 was primarily due to an examination settlement, state bonus depreciation, and timing and amount of other regulatory flow-through tax adjustments at IPC. The decreases were partially offset by additional income tax expense from greater pre-tax earnings at IDACORP and IPC, and lower tax credits from IFS.

In April 2009, the State of Idaho adopted the federal bonus depreciation provisions enacted as part of the ARRA. IPC s regulatory tax accounting method allows for the flow-through of certain state tax adjustments, including accelerated depreciation. Due to the application of the bonus depreciation provision, IPC was able to reduce its income tax expense by $2.2 million for the nine months ended September 30, 2009.

The Internal Revenue Service (IRS) completed its examination of IDACORP s 2006 tax year in May 2009. The 2006 examination report was submitted for U.S. Congress Joint Committee on Taxation (JCT) review in June. In July, the JCT completed its review and accepted the report without change. IDACORP considered all uncertain tax positions related to its 2006 tax year effectively settled as of the second quarter and decreased IPC s liability for unrecognized tax benefits by $1.3 million.

In March 2009, the JCT completed its review of IDACORP s 2001-2004 uniform capitalization appeals settlement and 2005 IRS examination report. The JCT accepted both items without change. IDACORP considered these matters effectively settled in 2008 and recorded the related financial effects in its December 31, 2008 financial statements.

The IRS began its examination of IDACORP s 2007-2008 tax years in July 2009. In May 2009, IDACORP formally entered the IRS Compliance Assurance Process (CAP) program for its 2009 tax year. The CAP program provides for IRS examination throughout the year. The 2007-2009 examinations are expected to be completed in 2010. IDACORP and IPC are unable to predict the outcome of these examinations.

LIQUIDITY AND CAPITAL RESOURCES:

Operating Cash Flows

IDACORP s and IPC s operating cash inflows for the nine months ended September 30, 2009, were $223 million and $208 million, respectively. These amounts were an increase of $107 million and $94 million, respectively, compared to the nine months ended September 30, 2008.

The following are significant items that affected operating cash flows in 2009:

The deferral of net power supply costs decreased $42 million and the collection of previously deferred net power supply costs increased $45 million compared to 2008.

Changes in net cash paid and refunded for income taxes of $30 million and $20 million at IDACORP and IPC, respectively, primarily due to audit settlements.

A refund of $13 million was made to IPC s transmission customers upon a final order from the FERC on IPC s OATT. The OATT is discussed further in REGULATORY MATTERS Federal Regulatory Matters OATT.

Net income increased by approximately $10 million compared to 2008.

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

Investing Cash Flows

IDACORP s and IPC s investing cash outflows were $147 million and $150 million, respectively for the nine months ended September 30, 2009. Investing cash outflows were primarily for IPC s utility construction and a $6 million investment in affordable housing at IFS. The outflows were partially offset by $9 million received from the sale of investments held by IFS, $2 million proceeds from the sale of the Southwest Intertie Project (SWIP) by IPC and $2 million proceeds from the sale of emission allowances by IPC.

Financing Cash Flows

IDACORP s and IPC s financing cash outflows for the nine months ended September 30, 2009 were $55 million and $40 million, respectively. The following significant items affected financing cash flows in 2009.

Debt: On August 20, 2009, IPC completed the remarketing of its $166.1 million Pollution Control Revenue Refunding Bonds and on August 25, 2009, IPC used the proceeds from the remarketed bonds to prepay its $170 million Term Loan Credit Agreement. On March 30, 2009, IPC issued $100 million of its 6.15 percent First Mortgage Bonds, Secured Medium-Term Notes, Series H, due April 1, 2019. On February 27, 2009, IFS repaid $7 million of its outstanding debt. IDACORP and IPC reduced short-term debt by $111 million and $109 million, respectively.

Equity: In September 2009, IDACORP received $9.2 million, net of agent s fees, from the issuance of 326,307 shares of common stock under its Continuous Equity Program (CEP). The average price of the shares sold was $28.63. Under the CEP, an additional 163,053 shares sold in September 2009 settled in October 2009 for net proceeds of $4.7

million. The average price of the shares settled in October was $29.10. Under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings Plan, IDACORP issued 283,071 shares for proceeds of $7.2 million.

IDACORP and IPC paid dividends of $43 million. IDACORP contributed $20 million in cash as additional equity to IPC in September 2009.

Economic Environment

IDACORP and IPC continue to assess the impact on their financial position, if any, of financial market developments, such as the bankruptcy and restructuring or merging of certain financial institutions. IDACORP and IPC continue to have access to the capital markets and have been able to generate funds internally and acquire funds externally to meet their capital requirements. IDACORP s and IPC s ability to attract the necessary financial capital at reasonable terms is critical to their overall strategic plan because IDACORP and IPC rely on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of funding for capital requirements not satisfied by internally generated funds. IDACORP and IPC expect that operating cash flows, together with the revolving credit facilities and other external financing, will be adequate to meet their operating and capital needs, although it is possible that changes in the global capital and credit markets could restrict or deny access to these markets on commercially acceptable terms.

Financing Programs

Shelf Registrations: As of October 29, 2009, IDACORP had approximately $574 million remaining on a shelf registration statement that can be used for the issuance of debt securities and common stock. As of October 29, 2009, IDACORP had 2,138,818 shares of common stock available to be issued pursuant to its Sales Agency Agreement with BNY Mellon Capital Markets, LLC, dated December 5, 2008. On March 30, 2009, IPC issued $100 million of its 6.15 percent First Mortgage Bonds due April 1, 2019. IPC used the net proceeds to repay a portion of its short-term debt in anticipation of using short-term debt to repay its $80 million 7.20 percent First Mortgage Bonds that mature on December 1, 2009. As of October 29, 2009, IPC had $130 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt.

Credit Facilities: The following table outlines available liquidity.

	September 30, 2009		**December 31, 2008**	
	IDACORP	**IPC**	**IDACORP**	**IPC**
Revolving credit facility	$ 100,000	$ 300,000	$ 100,000	$ 300,000
Commercial paper outstanding	(36,780)	-	(13,400)	(108,950)
Floating rate draw	-	-	(25,000)	-
Identified for other use [(1)]	-	(24,245)	-	(24,245)
Net balance available	$ 63,220	$ 275,755	$ 61,600	$ 166,805

[(1)] Port of Morrow and American Falls bonds that holders may put to IPC.

IDACORP s credit facility is a $100 million five-year credit agreement that terminates on April 25, 2012. IDACORP s credit facility, which is used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $100 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $10 million. IDACORP has the right to request an increase in the aggregate principal amount of the IDACORP facility to $150 million and to request one-year extensions of the then existing termination date. At September 30, 2009, no loans were outstanding on IDACORP s credit facility and $37 million of commercial paper was outstanding. At October 26, 2009, no loans and $29 million of commercial paper was outstanding.

IPC s credit facility is a $300 million five-year credit agreement that terminates on April 25, 2012. IPC s credit facility, which will be used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IPC has the right to request an increase in the aggregate principal amount of the IPC facility to $450 million and to request one-year extensions of the then existing termination date. At September 30, 2009, no loans and no commercial paper were outstanding on IPC s credit facility. At October 26, 2009, no loans and $6 million of commercial paper was outstanding.

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

Debt Covenants: The IDACORP credit facility and the IPC credit facility each contain covenants requiring the company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization of no more than 65 percent as of the end of each fiscal quarter. At September 30, 2009, the leverage ratios for IDACORP and IPC were 50 percent and 52 percent, respectively. At September 30, 2009, IDACORP and IPC were each in compliance with all other covenants in their respective credit facilities. Please refer to IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008, for a discussion of additional debt covenants.

Pollution Control Revenue Refunding Bonds and Term Loan Credit Agreement: On April 3, 2008, IPC made a mandatory purchase of two series of Pollution Control Revenue Refunding Bonds issued for the benefit of IPC, the $116.3 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2006 issued by Sweetwater County, Wyoming due 2026 and the $49.8 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2003 issued by Humboldt County, Nevada due 2024 (together the Pollution Control Bonds). IPC initiated this transaction in order to adjust the interest rate period of the Pollution Control Bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008. This change was made to mitigate the higher-than-anticipated interest costs in the auction mode, which was a result of the financial guarantor s credit ratings deterioration.

On August 20, 2009, J.P. Morgan Securities, Inc. acting as Remarketing Agent, purchased the Pollution Control Bonds from IPC for remarketing to the public. The Humboldt County Bonds carry a 5.15 percent term interest rate and mature on December 1, 2024. The Sweetwater County Bonds carry a 5.25 percent term interest rate and mature on July 15, 2026. The Pollution Control Bonds are not subject to redemption for 10 years, except for extraordinary optional and mandatory redemption prior to maturity, in each case at 100 percent of the principal amount, plus accrued interest if any to the date of redemption. In connection with the remarketing of the Pollution Control Bonds, the financial guaranty insurance policies securing the Pollution Control Bonds were terminated.

On August 25, 2009, IPC used proceeds from the reoffering of the Pollution Control Bonds and additional corporate funds to prepay its $170 million loan under a Term Loan Credit Agreement dated as of February 4, 2009, among JPMorgan Chase Bank, N.A., as administrative agent and lender, Bank of America, N.A. and Wachovia Bank, National Association, as lenders.

Credit Ratings

Access to capital markets at a reasonable cost is determined in large part by credit quality. The following table outlines the current S&P, Moody s and Fitch Ratings, Inc. (Fitch) ratings of IDACORP s and IPC s securities:

	S&P		**Moody s**		**Fitch**	
	IPC	**IDACORP**	**IPC**	**IDACORP**	**IPC**	**IDACORP**
Corporate Credit Rating	BBB	BBB	Baa1	Baa2	None	None
Senior Secured Debt	A-	None	A3	None	A-	None
Senior Unsecured Debt	BBB	BBB-	Baa1	Baa2	BBB+	BBB
Short-Term Tax-Exempt Debt	BBB-/A-2	None	Baa1/ VMIG-2	None	None	None
Commercial Paper	A-2	A-2	P-2	P-2	F-2	F-2
Credit Facility	None	None	Baa1	Baa2	None	None

Rating Outlook	Stable	Stable	Negative	Negative	Negative	Negative

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

Capital Requirements

IPC is experiencing a cycle of heavy infrastructure investment, adding capacity to its baseload generation, transmission system and distribution facilities to ensure adequate supply of electricity, to provide service to new customers and to maintain system reliability. IPC 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. Due to the heavy infrastructure requirements from 2009-2011, IPC continues to focus on critical infrastructure needs that relate to system reliability and resource adequacy and has reduced ongoing capital expenditures and major projects excluding Langley Gulch power plant from prior estimates. The table below presents the low and high ranges of the capital expenditure categories. It is expected that total capital expenditures will be near the midpoint of the estimated range, between $975 million and $1 billion, including Langley Gulch from 2009 - 2011. Internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2009 through 2011. While IDACORP and IPC expect minimal need for external financing in 2009 and 2010, except for issuances under the dividend reinvestment and employee-related plans, should IDACORP and IPC decide to access the capital markets, IDACORP has access to its CEP with approximately 2.1 million shares of common stock available and IPC has $130 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt. IDACORP and IPC expect to continue financing capital requirements with a combination of internally generated funds and externally financed capital.

The following table presents IPC s estimated cash requirements for construction, excluding AFUDC, for 2009 through 2011 (in millions of dollars):

	2009	2010-2011
Ongoing capital expenditures	$135-140	$320-325
Advanced Metering Infrastructure (AMI)	20-22	40-50
Major projects excluding Langley Gulch (detailed below)	50-53	70-75
Transmission for Langley Gulch	-	15-20
Total excluding Langley Gulch project	$205-215	$445-470
Langley Gulch power plant (detailed below)	50-55	260-270
Total	$255-270	$705-740

Major Projects:

Langley Gulch Power Plant (2012 Baseload Resource): On September 1, 2009, the IPUC issued an order granting IPC s March 6, 2009, request for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant. The order also provided for cost recovery and ratemaking assurances requested by IPC related to the power plant. Langley Gulch will be a natural gas-fired combined cycle combustion turbine (CCCT) generating plant with a summer nameplate capacity of approximately 300 MWs and a winter capacity of approximately 330 MWs. The plant will be constructed near New Plymouth, Idaho, commencing in summer 2010, and is anticipated to achieve commercial operation by November 1, 2012. Contract incentives may advance the commercial operation date to July 1, 2012. The plant will connect to IPC s existing grid.

The need for a baseload generating resource was identified in IPC s 2004 and 2006 IRP and the 2008 plan update. Langley Gulch was selected as the result of a competitive Request for Proposal (RFP) process IPC issued in April 2008. Proposals received from independent power supply developers as well as a proposed IPC owned and operated CCCT option, were evaluated. An independent consultant assisted IPC with the evaluation process, which considered price and non-price attributes of the responses to the RFP. Langley Gulch was identified as the preferred resource due to its lower cost. Other beneficial attributes include its operating flexibility and location.

IPC requested in its application that the IPUC provide IPC with assurances of future ratemaking treatment for construction costs up to IPC s cost estimate of $427.4 million. In the order, the IPUC found that IPC had satisfied statutory requirements that would entitle IPC to receive such ratemaking assurances. The order grants IPC assurance and pre-approval to include $396.6 million of construction costs in IPC s rate base when Langley Gulch achieves commercial operation. The order contemplates that IPC may request recovery of additional costs if they exceed $396.6 million provided that IPC is able to demonstrate that the additional costs were reasonably and prudently incurred.

For the project, IPC entered into two equipment supply contracts with Siemens Energy, Inc. (Siemens) a gas turbine purchase agreement (Gas Turbine Agreement) dated December 19, 2008, and a steam turbine purchase agreement (Steam Turbine Agreement) dated February 11, 2009. Each contract requires: IPC to pay a fixed price for the equipment; Siemens to guarantee delivery of the equipment to the site by specific dates that will accommodate the project schedule, or incur liquidated damages; Siemens to guarantee that the equipment will meet specified performance and emission standards, or incur liquidated damages; Siemens to warrant for a period of time that the equipment is free from defects; and Siemens to provide certain technical field assistance and consultation services under the contracts.

IPC issued a Full Notice to Proceed (FNTP) to Siemens under the Gas Turbine Agreement on September 4, 2009. As of September 30, 3009, IPC has paid Siemens $13 million, or 25 percent of the total amount due under the contract. Monthly contract payments will continue through January 2011 when 97 percent of the total amount is due. The remaining three percent of the contract will be paid in two payments; one in April 2012 and the other upon fulfillment of the final acceptance criteria.

Siemens started engineering activities on August 3, 2009, under the Steam Turbine Agreement. As of September 30, 2009, IPC has paid $6 million, or 17 percent of the total amount due under the contract. Additional contract payments are due in March 2010, September 2010, and April 2011 that will bring the total payments to 98 percent of the amount due. The remaining two percent of the contract will be paid upon fulfillment of the final acceptance criteria.

On May 7, 2009, IPC entered into an Engineering, Procurement and Construction Services Agreement (EPC Agreement) with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company (collectively, the Contractor), for design, engineering, procurement, construction management and construction services for Langley Gulch. The EPC Agreement is the primary agreement governing the development of Langley Gulch, providing for the specific design, engineering, and construction to be performed, as well as equipment procurement. The total contract price to be paid by IPC under the EPC Agreement is approximately one-half of the projected $427 million total project cost. IPC issued a FNTP to the Contractor on September 4, 2009, authorizing the Contractor to commence and complete all work under the EPC Agreement. IPC is required to make monthly progress payments to the Contractor under the EPC Agreement beginning in October 2009. The first twelve monthly progress payments between October 2009 and September 2010 will represent approximately 25 percent of the total payments scheduled to be made by IPC under the EPC Agreement.

IPC is responsible for specific portions of the Langley Gulch Project, which include permitting the site under the Payette County planning and zoning ordinance, design and construction of the cooling water pump station and pipeline from the Snake River to the site, design and construction of the gas pipeline from the Williams Northwest Pipeline to the site, and design and construction of the new electric transmission lines to the existing grid. The cost of these activities are included in the $427 million estimated total cost for Langley Gulch.

Hemingway Station: Construction of a new 500-kV station named Hemingway, located in the vicinity of Melba and Murphy, Idaho near Boise, is expected to address growth, capacity and operating constraints to ensure reliable service to IPC s network and native load customers while meeting mandatory regulatory reliability requirements. The station was originally part of the Gateway West Project but the timing of this addition was accelerated to 2010 to help meet forecast deficits and improve reliability. Cost estimates for the project, including rights-of-way, permitting and substation interconnections are included in the above table and total approximately $52 million.

Hemingway-Bowmont Transmission Line: As part of the Hemingway Station Project, the Hemingway-Bowmont transmission line is expected to provide power to the Treasure Valley in southwest Idaho by 2010. The Hemingway-Bowmont line will consist of 12 miles of new 230-kV double circuit transmission line. Originally, this transmission line was planned to pass near Bowmont and terminate at Hubbard. The estimate for this project is approximately $15 million, and is included in the above table. The original plan called for 12 miles of new line and reconstruction of 17 miles of existing 138-kV transmission line to 230-kV. The change of termination points from Hubbard to Bowmont allows the Hemingway Station to be energized and provide improved reliability at a reduced cost. The 230-kV connection between Bowmont and Hubbard will be built in the future as system needs dictate.

Boardman-Hemingway Line: The Boardman-Hemingway Line is a proposed 500-kV transmission project between a substation near Boardman, Oregon and the Hemingway station. This line will provide transmission service for existing network and native load customers and their forecasted growth and for existing third party transmission service requests. This project is expected to relieve existing congestion by increasing transmission capacity and improving reliability to ensure compliance with mandatory regulatory reliability requirements. It will allow for the transfer of up to 1,500 MW of additional energy between Idaho and the Northwest. The initial project phase estimate of $50 million will be funded by IPC and includes the engineering, environmental review, permitting and rights-of-way. On March 9, 2009, IPC initiated a community advisory process to engage the public in a final route selection in compliance with the National Environmental Policy Act and Energy Facility Siting Council requirements. Cost estimates for the 2009-2011 time frame of the initial phase are included in the above table. Cost estimates for the project (including initial phase project estimate and construction costs of the line) are approximately $600 million. IPC expects to seek partners for up to 50 percent of the project when construction commences. The project is expected to be completed in 2015 subject to siting, permitting and regulatory approvals. Construction costs are currently not included in IPC s 2009 to 2011 forecast.

61

Gateway West Project: IPC and PacifiCorp are jointly exploring the Gateway West project to build transmission lines between Windstar, a substation located near Douglas, Wyoming and the Hemingway station. This project will provide transmission service for existing network and native load customers and their forecasted growth and provides for existing third party transmission service requests. It is expected to relieve existing congestion by increasing transmission capacity and improving reliability to ensure compliance with mandatory regulatory reliability requirements. IPC and PacifiCorp have a cost sharing agreement for expenses associated with the analysis work of the initial phases. IPC s share of the initial phase of engineering, environmental review, permitting and rights-of-way is approximately $40 million and cost estimates for the 2009-2011 timeframe of the initial phase are included in the above table. Construction costs are not included in IPC s 2009 to 2011 forecast. Initial phases of the project could be completed by 2014 depending on the timing of rights-of-way acquisition, siting and permitting, and construction sequencing. If all initial phases are constructed, IPC estimates that its share of project costs could range between $500 million and $600 million. Remaining phases of the project could be constructed as demand requires. On July 16, 2009, the Bureau of Land Management (BLM), IPC and PacifiCorp announced an agreement to extend the time period for the public to submit reasonable alternatives into the draft environmental impact statement (Draft EIS) for the project. Additional line route alternatives were received by the BLM on or before the September 4, 2009 deadline. The Draft EIS was originally scheduled to be issued in August or September 2009, however, the extension of time for public input will delay the issuance of the Draft EIS until the second quarter of 2010. It is not known how this will ultimately affect the construction schedule.

Other capital requirements: IDACORP s non-regulated capital expenditures are expected to be $15 million in 2009 and $5 million in 2010 and primarily relate to IFS s tax-structured investments.

Contractual Obligations

The following items are the material changes to contractual obligations made outside of the ordinary course of business since December 31, 2008:

IPC entered into a contract to purchase coal from the Black Butte Coal Company for use at the Jim Bridger generating plant, in which IPC holds a one-third ownership. IPC s coal purchases under the contract are expected to total $127 million from 2010 to 2014.

On March 30, 2009, IPC issued $100 million of its 6.15 percent First Mortgage Bonds, Secured Medium-Term Notes, Series H, due April 1, 2019.

On May 13, 2009, IFS issued a $6 million equity funding obligation to finance its investment in affordable housing. The obligation is scheduled to mature in 2010.

In February, 2009, IPC entered into a contract with EnerNOC to implement and operate a demand response program for its commercial and industrial customers. IPC estimates it will spend approximately $12.2 million on the program during the five year term of the contract.

As discussed above in Capital Requirements Major Projects Langley Gulch Power Plant (2012 Baseload Resource), IPC entered into two contracts with Siemens to purchase gas and steam turbine equipment for Langley Gulch. IPC estimates it will spend approximately $90 million on the contracts from 2009 through 2012.

As discussed above in Capital Requirements Major Projects Langley Gulch Power Plant (2012 Baseload Resource), IPC entered into a contract with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company for design, engineering, procurement, construction management and construction services for Langley Gulch. The total contract price to be paid by IPC under the EPC Agreement is approximately one-half of the projected $427 million total project cost for Langley Gulch from 2009 to 2012.

On June 30, 2009, IPC entered into a contract with Cargill Environmental Finance to purchase the output from the Bettencourt B6 dairy anaerobic digester located near Jerome, Idaho. IPC expects the contract to total $8 million from 2009 to 2029. This agreement does not have a specified term.

In the third quarter, IPC entered into several purchased power agreements with wind and other alternate energy developers. These agreements are expected to total approximately $313 million from 2010 to 2030.

On August 12, 2009, IPC entered into a multi-year Tribal Water Rental Agreement with the Shoshone-Bannock Tribal Water Supply Bank. The agreement is expected to total approximately $10 million from 2009 to 2013.

On September 1, 2009, IPC entered into a purchased power contract with Idaho Winds, LLC. IPC s energy purchases under the contract are expected to total $105 million from 2012 to 2032

Pension funding has been revised downward, as discussed below.

Pension Plan

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, companies are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. The WRERA also provides for asset smoothing, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. IPC has elected to use asset smoothing. On March 31, 2009, the U.S. Department of the Treasury (Treasury) provided guidance on the selection of the corporate bond yield curve for determining plan liabilities and allows companies to choose from the range of months in selecting a rate, rather than requiring the use of prescribed rates. The Treasury s announcement specifically referenced 2009, but also indicated that technical guidance will be forthcoming to address future years.

The IRS and Treasury have issued final regulations effective October 15, 2009 which apply to plan years beginning on or after January 1, 2010 which provided guidance regarding the determination of the value of plan assets and benefit liabilities for purposes of the funding requirements that apply to single employer defined benefit plans, regarding the use of certain funding balances and regarding benefit restrictions for certain underfunded defined benefit pension plans. These regulations reflect provisions added by the PPA, as amended by the WRERA. These final regulations are substantially consistent with earlier guidance and IDACORP and IPC do not expect implementation to materially change existing estimates relating to pension plan contributions.

The revisions in the PPA, WRERA, Treasury guidance and IRS guidance resulted in IDACORP and IPC revising the funded status of their pension plan at January 1, 2009, to above the minimum required funding levels and reducing or delaying future required contributions from what was previously disclosed. Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, IDACORP and IPC have not contributed and are not required to contribute to their pension plan in 2009, and estimated minimum required contributions will be approximately $6 million in 2010, $46 million in each of 2011 and 2012, and $41 million in 2013. IDACORP and IPC may elect to make contributions earlier than the required dates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

REGULATORY MATTERS:

Idaho Rate Cases

2009 General Rate Case Notice of Intent to File: On August 28, 2009, IPC filed with the IPUC a notice of intent to file a general rate case on or after October 28, 2009. The notice of intent provides IPC with a 60-day window, beginning October 28, 2009, in which it is permitted to file a new general rate case. Since the filing of the notice of intent, IPC has reached an agreement in principle with its customer groups and IPUC Staff regarding a number of rate issues that may avoid the anticipated general rate case filing. This agreement will be memorialized in a formal settlement stipulation and together with supporting testimony will be filed in early November with the IPUC for approval.

2008 General Rate Case: On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. On February 19, 2009, IPC filed a request for reconsideration with the IPUC and on March 19, 2009, the IPUC issued an order that increased IPC s Idaho revenue requirement by an additional $6.1 million to approximately $27 million for this rate case, raising the average rate increase from 3.1 percent to 4.0 percent.

The IPUC denied reconsideration with respect to a refund of $3.3 million of fees recovered by IPC from the FERC. On April 2, 2009, IPC filed an application with the IPUC for an accounting order approving amortization of the fees over a five year period beginning October 2006 when IPC received the FERC credit. The IPUC approved IPC s requested amortization period in an order issued on April 28, 2009. In the first quarter of 2009, IPC recorded a charge of approximately $1.7 million to electric utility other operations expense and a corresponding regulatory liability for the amount to be refunded from February 1, 2009, through the end of the amortization period, September 2011. As the regulatory liability is amortized it will reduce electric utility other operations expense ratably over the remaining amortization period.

The January 30, 2009 order authorized approximately $15 million related to increases in base net power supply costs. It also allowed IPC to include in rates approximately $6.8 million ($10.6 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase will improve cash flows but will not have a current impact on IPC s net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

Idaho Ratemaking Treatment Act: Senate Bill 1123 was signed into law on April 9, 2009, and became effective on July 1, 2009. This legislation establishes an additional voluntary process for consideration of utility capital expenditures, whereby the IPUC may authorize and pre-approve ratemaking treatment for qualified capital construction projects of IPC and other Idaho utilities. This legislation expands the IPUC s ability to shape the resources in a utility s portfolio before construction of, or commitment to, such a resource and it also provides additional surety to capital markets that utility expenditures are prudent and pose less risk of financial loss due to a guaranteed rate of return.

Langley Gulch (2012 Baseload Resource)

On March 6, 2009, IPC filed an application with the IPUC for a CPCN authorizing IPC to construct, own and operate the Langley Gulch power plant. On September 1, 2009, the IPUC issued its order granting a CPCN for the Langley Gulch project and providing related cost recovery and ratemaking assurances requested by IPC. The IPUC concluded that IPC s planning decisions with respect to Langley Gulch were just and reasonable and that IPC s pursuit, development and implementation of cost-effective demand-side management, conservation, energy efficiency and electricity pricing options were diligent and commendable. The IPUC found that IPC satisfied the requirements for a CPCN and that the public interest required construction of Langley Gulch in the manner, time frame and location proposed by IPC in the application.

IPC requested in its application that the IPUC provide IPC with assurances of future ratemaking treatment for construction costs up to IPC s cost estimate of $427.4 million. In the order, the IPUC found that IPC had satisfied statutory requirements that would entitle IPC to receive such ratemaking assurances. The order grants IPC assurance and pre-approval to include $396.6 million of construction costs in IPC s rate base when Langley Gulch achieves commercial operation. The order contemplates that IPC may request recovery of additional costs if they exceed $396.6 million, provided that IPC is able to demonstrate that the additional costs were reasonably and prudently incurred.

The application also requested (1) authorization to include construction work in progress (CWIP), in rate base for all or a portion of the construction expenditures and (2) that the return on equity be the same as the return on equity authorized for the rest of IPC s rate base when Langley Gulch achieves commercial operation. The order authorized the requested return on equity, but the IPUC concluded in the order that it did not have sufficient evidence in the record to support authorization of CWIP at this time. The IPUC advised that it is willing to consider including CWIP in the IPC rate base in the future as construction progresses.

In the order, the IPUC conditioned its granting of assurances of future ratemaking treatment on the receipt of quarterly progress reports from IPC addressing the construction schedule, actual progress against the schedule and estimates of costs incurred for Langley Gulch, as well as projections of deviations in such schedules or costs. The initial quarterly report is expected to be filed in December 2009. The order also directed IPC to prepare and file a new depreciation study shortly after Langley Gulch achieves commercial operation.

Please see further discussion of the Langley Gulch project in LIQUIDITY AND CAPITAL RESOURCES - Major Projects - Langley Gulch Power Plant (2012 Baseload Resource).

Special Customer Electric Service Agreements

Micron: On January 26, 2009, the IPUC granted authority to temporarily amend IPC s electric service agreement with one of its largest customers, Micron Technology, Inc. (Micron) for the period January 1, 2009, through June 30, 2009 to provide Micron flexibility in restructuring its operations. This amendment did not have a significant impact on IPC s earnings. On June 17, 2009 IPC filed a subsequent application requesting an order approving an extension of the temporary amendment to the electric service agreement through December 31, 2009. The extension is not expected to have a significant impact on IPC s 2009 earnings. The IPUC approved IPC s application on July 31, 2009.

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

On May 27 and June 19, 2009, IPC and Hoku amended certain provisions of the electric service agreement (Amended ESA). The Amended ESA was filed with the IPUC for approval on June 22, 2009, and approved by the IPUC on July 24, 2009. Under the Amended ESA, the starting date for Hoku s required purchases of power under the ESA will be delayed from June 1, 2009 to December 1, 2009. Under the Amended ESA (i) IPC will provide electricity to Hoku at the current Schedule 19 Large Industrial tariff rate through November 30, 2009; (ii) Hoku will take no more than 5 MW of electric power through July 2009, 10 MW during August 2009 and 25 MW for each month from September through November 2009; (iii) Hoku will take reduced levels of electric power of no more than 43 MW during the period June 16, 2012 through August 15, 2012 and 67 MW during the period August 16, 2012 through September 15, 2012; and (iv) Energy Efficiency Rider charges will be added to a portion of the electricity demand charges, beginning on December 1, 2011.

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

Oregon Rate Cases

2009 General Rate Case: On July 31, 2009, IPC filed an application with the OPUC requesting an average rate increase of approximately 22.6 percent, or $7.3 million annually. The application included a requested return on equity of 11.25 percent and an overall rate of return of 8.68 percent with equity at 49.8 percent of total capitalization. Oregon jurisdictional rate base included in the application is $110.8 million. IPC filed its case based upon a 2009 test year. The new rates were filed with a requested effective date of August 31, 2009. On August 25, 2009, the OPUC suspended IPC s application for nine months and set a hearing schedule. A public workshop was held on September 29, 2009. Settlement conferences are scheduled for November 4-5, 2009 and December 10, 2009. Oral argument is set for February 24, 2010, and hearings begin on February 25, 2010. IPC is unable to predict what relief the OPUC will grant.

Deferred Net Power Supply Costs

The following table presents the balances of deferred net power supply costs, including applicable carrying charges:

	September 30, 2009		December 31, 2008	
Idaho PCA current year:				
Deferral for the 2009-2010 rate year	$	-	$	93,657
Deferral for the 2010-2011 rate year		26,121		-
Idaho PCA true-up awaiting recovery:				
Authorized in May 2008		-		47,164
Authorized in May 2009		66,716		-
Oregon deferral:				
2001 Costs		-		1,663
2006 Costs		2,285		1,215
2007 Costs		6,105		-
2008 Power cost adjustment mechanism		5,725		5,400
Total deferral	$	106,952	$	149,099

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks IPC s actual net power supply costs (fuel, purchased power and third-party transmission expenses less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates.

The annual adjustments are based on two components:

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

A true-up component, based on the difference between the previous year s actual net power supply costs and the previous year s forecast. This 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 true-up component is calculated monthly, and interest is applied to the balance.

Prior to February 1, 2009, the PCA mechanism provided that 90 percent of deviations in power supply costs were to be reflected in IPC s rates for both the forecast and the true-up components. Effective February 1, 2009, this sharing percentage was changed to 95 percent.

2009-2010 PCA: On May 29, 2009, the IPUC approved the 2009-2010 PCA of $84.3 million or 10.2 percent, effective June 1, 2009.

The 2009-2010 PCA reflects a new methodology discussed in PCA Workshops below that utilizes IPC s most recent operating plan to forecast power supply expenses rather than the previous method based on a forecast of Brownlee Reservoir inflow and a regression formula.

2008-2009 PCA: On May 30, 2008, the IPUC approved IPC s 2008-2009 PCA and an increase to then-existing revenues of $73.3 million, effective June 1, 2008, which resulted in an average rate increase to IPC s customers of 10.7 percent. The IPUC s order adopted an IPUC Staff proposal to use a forecast for power supply costs that equaled the amounts in current base rates. The revenue increase was net of $16.5 million of gains from the 2007 sale of excess SO_2 emission allowances, including interest, which the IPUC ordered be applied against the PCA.

PCA Workshops: In its May 30, 2008 order approving IPC s 2008-2009 PCA, the IPUC directed IPC to set up workshops with the IPUC Staff and several of IPC s largest customers (together, the Parties) to address PCA-related issues not resolved in the PCA filing. Workshops were conducted in the fall and a settlement stipulation was filed with the IPUC and approved on January 9, 2009.

The following changes were effective as of February 1, 2009:

PCA sharing ratio the PCA allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent). The previous sharing ratio was 90/10.

LGAR the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. In the stipulation, the Parties agreed on the formula for calculating the LGAR. Based on the final rates approved by the IPUC in the 2008 general rate case and the supporting data, the current LGAR is $26.63 per MWh, effective February 1, 2009.

Use of IPC s operation plan power supply cost forecast the operation plan forecast may better match current collections with actual net power supply costs in the year they are incurred and result in smaller amounts being included in the following year s true-up rate, beginning with the 2009-2010 PCA filing.

Inclusion of third-party transmission expense transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of net power supply costs. Deviation in these costs from levels included in base rates is now reflected in PCA computations.

Adjusted distribution of base net power supply costs base net power supply costs are distributed throughout the year based upon the monthly shape of normalized revenues for purposes of the PCA deferral calculation.

Oregon: IPC has a power cost recovery mechanism in Oregon with two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows IPC to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

The APCU allows IPC 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 APCU has two components: the October Update, where each October IPC calculates its estimated normalized net power supply expenses for the following April through March test period, and the March Forecast, where each March IPC files a forecast of its expected net power supply expenses for the same test period, updated for a number of variables including the most recent stream flow data and future wholesale electric prices. On June 1 of each year, rates are adjusted to reflect costs calculated in the APCU.

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, IPC 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 IPC 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 IPC. However, a collection will occur only to the extent that it results in IPC s actual return on equity (ROE) for the year being no greater than 100 basis points below IPC s last authorized ROE. A refund will occur only to the extent that it results in IPC s actual ROE for that year being no less than 100 basis points above IPC s last authorized ROE. The PCAM rate is then added to or subtracted from the APCU rate, subject to certain statutory limitations discussed below, with new combined rates effective each June 1.

2010 APCU: On October 19, 2009, IPC filed the October Update portion of its 2010 APCU with the OPUC. The filing reflects that revenues associated with IPC s base net power supply costs would be increased by $2.6 million over the current APCU, an average 8.2 percent increase. The actual impact of the 2010 APCU will be determined once the March Forecast portion is filed in March 2010 and combined with the October Update. Final rates are expected to become effective on June 1, 2010.

2009 APCU: On October 23, 2008, IPC filed the October Update portion of its 2009 APCU with the OPUC. The filing, combined with supplemental testimony filed on December 1, 2008, reflects that revenues associated with IPC s base net power supply costs would be increased by $1.6 million over the previous October Update, an average 4.6 percent increase.

On March 20, 2009, IPC filed the March Forecast portion of its 2009 APCU. When combined with the October Update, the March Forecast resulted in a requested increase to Oregon revenues of 11.5 percent, or $3.9 million annually. On May 26, 2009, the OPUC approved the requested rate increase effective June 1, 2009.

2008 APCU: On May 20, 2008, the OPUC approved IPC s 2008 APCU (comprising both the October Update and the March Forecast) with the new rates effective June 1, 2008. The approved APCU resulted in a $4.8 million, or 15.7 percent, increase in Oregon revenues.

2008 PCAM: On February 27, 2009, IPC filed the true-up of its net power supply costs for the period January 1 through December 31, 2008, with the OPUC. The 2008 PCAM filing reflects a deviation of actual net power supply costs above the forecast for that period of $7.4 million. After the application of the deadband, the filing requests that $5.0 million be added to IPC s true-up balancing account and amortized sequentially after the amounts discussed below under Oregon Excess Power Cost Deferrals. A pre-hearing conference was held on April 27, 2009, to discuss the status of the case. A joint workshop and settlement conference was held July 7, 2009. As a result of the conference, IPC filed supplemental testimony on October 14, 2009, that reflects agreed upon changes to the calculation of the deferral. The revised 2008 PCAM filing now reflects a deviation of actual net power supply costs above the forecast for that period of $7.7 million and requests that $5.1 million be added to IPC s true-up balancing account and amortized sequentially.

Oregon Excess Power Cost Deferrals: The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year ($1.9 million for 2009 based on 2008 revenues). On October 6, 2008, the OPUC issued an order clarifying that the PCAM is also a deferral under the Oregon statute. The following deferrals were authorized under processes existing prior to the establishment of the PCAM.

May-December 2007 Excess Power Costs: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than normal (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon s jurisdictional share of excess power supply costs of $5.7 million. Settlement discussions were held in February 2009. As a result of those discussions, the parties to the proceeding reached a settlement and a stipulation was filed with the OPUC on April 8, 2009. In the stipulation, the parties agreed to limit the calculation of excess net power supply costs in this docket to the eight-month period from May 1 through December 31, 2007. Based on the methodology adopted by the parties to the stipulation, it was determined that IPC should be allowed to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for that period. The amount to be recovered was reduced by $0.9 million of emission allowance sales (including interest) during the same period allocated to Oregon, resulting in an approved deferral balance of $5.5 million. IPC recorded the $6.4 million deferral in the second quarter 2009 as a reduction to power cost adjustment expense. The emission allowances sales were previously deferred. The parties also agreed that the excess power supply costs from the period beginning in 2008 would be deferred pursuant to the PCAM agreement established as part of the power cost variance filing for 2008 and calculated according to the PCAM. On May 28, 2009, the OPUC issued its order adopting the stipulation.

2006-2007 Excess Power Costs: On June 30, 2009, IPC filed an application with the OPUC to begin amortizing through rates the 2006-2007 deferral of $2.0 million plus $0.4 million of accrued interest, effective September 1, 2009. The OPUC issued an order approving IPC s application on September 1, 2009. IPC expects amortization of this deferral to take approximately 16 months. The May 1 - December 31, 2007 deferral of $6.1 million (net of the emission allowance adjustment and including accrued interest) and the $5.7 million 2008 PCAM balance (including accrued interest) will be recovered sequentially following the full recovery of the 2006-2007 deferral.

Fixed Cost Adjustment Mechanism (FCA)

On March 12, 2007, the IPUC approved the implementation of a FCA mechanism pilot program for IPC s residential and small general service customers. The pilot program began on January 1, 2007, and runs through 2009. The FCA is a rate mechanism designed to remove IPC s disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. In the FCA, for each customer class, the number of customers is multiplied by a fixed cost per customer. The cost per customer is based on IPC s revenue requirement as established in a general rate case. This authorized fixed cost recovery amount is compared to the amount of fixed costs actually recovered by IPC. The amount of over- or under-recovery is then returned to or collected from customers in a subsequent rate adjustment. On October 1, 2009, IPC filed an application with the IPUC to make the FCA mechanism permanent beginning with the June 1, 2010 rate change.

On May 29, 2009, the IPUC approved a rate increase, effective June 1, 2009 through May 31, 2010, to recover $2.7 million of fixed costs under-recovered during 2008. On May 30, 2008, the IPUC approved a rate reduction, effective June 1, 2008 through May 31, 2009, to return $2.4 million of fixed costs over-recovered in 2007.

IPC has deferred fixed costs of $5.0 million related to the FCA during the first nine months of 2009.

Energy Efficiency Matters

Idaho Energy Efficiency Rider (Rider): IPC s Rider is the chief funding mechanism for IPC s investment in energy efficiency and demand response programs. On May 29, 2009, the IPUC approved IPC s application to increase the Rider to 4.75 percent of base revenues effective June 1, 2009. Based on 2008 test year revenue, IPC expects Rider revenues of $27.3 million in 2009 and $33.2 million in each of 2010 and 2011.

Effective June 1, 2008, IPC began collecting 2.5 percent of base revenues, or approximately $17 million annually, under the Rider. Prior to that date, IPC collected 1.5 percent of base revenues, with funding caps for residential and irrigation customers.

Energy Efficiency Prudency Review: In the 2008 general rate case, IPC requested that the IPUC explicitly find that IPC s expenditures between 2002 and 2007 of $29 million of funds obtained from the Rider were prudently incurred and would, therefore, no longer be subject to potential disallowance. The IPUC Staff recommended that the IPUC defer a prudency determination for these expenditures until IPC was able to provide a comprehensive evaluation package of its programs and efforts. IPC contended that sufficient information had already been provided to the IPUC Staff for review.

On February 18, 2009, IPC filed a stipulation with the IPUC reflecting an agreement with the IPUC Staff on $14.3 million of the Rider funds. The IPUC Staff agreed that this portion of the Rider expenditures were prudently incurred. On March 6, 2009, the IPUC approved the stipulation, identifying $18.3 million as prudent, which included $14.3 million of Rider funding and $4.0 million of other funds.

On April 1, 2009, IPC filed an application with the IPUC seeking a prudency determination on the $14.7 million balance of Rider funds spent during 2002 through 2007. IPC has requested that this application be processed under modified procedure.

On October 5, 2009, IPC and other investor-owned electric utilities serving in Idaho engaged in an informal public workshop with the IPUC Staff to discuss how energy efficiency evaluation and prudency will be determined on a prospective basis. The IPUC Staff is expected to propose a process for energy efficiency expenditure approval as a result of the workshop.

Commercial Demand Response: On March 2, 2009, IPC filed for approval of a voluntary Commercial Demand Response program for commercial and industrial customers larger than 200 kilowatts. IPC signed a five-year contract with a third-party aggregator, EnerNOC, to operate the program and make arrangements with IPC s customers to achieve peak reductions. This program is dispatchable (meaning IPC will have flexibility to schedule peak reduction benefits during times of greatest need) and, in the next four years, is expected to increase to 50 MW of summer peak demand reduction availability by 2012. The anticipated cost of the program, which will be funded through the Rider, is approximately $12.2 million over its first five years. The IPUC approved the program on May 15, 2009.

Irrigation Demand Response Peak Rewards: On November 7, 2008, IPC filed a revised Irrigation Peak Rewards program design with the IPUC which was approved on January 14, 2009. The program is expected to provide an overall peak reduction of about 144 MW in 2009. Participating customers will receive a credit on their bills in exchange for allowing IPC, within specified parameters, to interrupt service to their irrigation pumps during certain peak hours in a six-week period in June and July. The anticipated cost of the irrigation program, which is funded through the Rider, is $6.7 million in 2009 and is expected to increase to approximately $10.8 million by 2011.

Renewable Energy Certificates

On November 14, 2008 IPC filed an application requesting authority from the IPUC to retire renewable energy certificates (RECs), sometimes referred to as green tags associated with the Elkhorn Valley Wind Project and the Raft River Geothermal Project. IPUC Staff and the Industrial Customers of Idaho Power (ICIP) filed comments opposing the retirement of IPC s RECs, while various environmental groups expressed support. On January 26, 2009, the IPUC approved IPC s application requesting authority to retire the RECs. Thereafter ICIP filed a Petition for Reconsideration which was granted. On May 20, 2009 the IPUC reversed its decision and ordered IPC to sell its eligible RECs generated in 2007 and 2008. It is expected that the proceeds from the sale of the RECs will be included in IPC s 2010 PCA filing.

Depreciation Filings

On September 12, 2008, the IPUC approved a revision to IPC s depreciation rates, retroactive to August 1, 2008. The new rates are based on a settlement reached by IPC and the IPUC Staff, and result in an annual reduction of depreciation expense of $8.5 million ($7.9 million allocated to Idaho) based upon December 31, 2006, depreciable electric plant in service.

On October 3, 2008, IPC filed an application with the OPUC requesting that the new depreciation rates approved in IPC s Idaho jurisdiction be authorized for IPC s Oregon jurisdiction as well. The result for the Oregon jurisdiction would be a decrease in annual depreciation expense and rates of $0.4 million (excluding the impacts of accelerated depreciation of existing Oregon meters as discussed below in Advanced Metering Infrastructure (AMI) - Oregon). On August 18, 2009, the OPUC approved a stipulation whereby the OPUC Staff agreed not to make adjustments to the depreciation rates adopted by the IPUC. IPC committed to joint involvement of OPUC Staff prior to submitting future depreciation rates for approval in IPC s Idaho jurisdiction.

On December 3, 2008, the FERC approved IPC s request to use the IPUC-approved depreciation rates in future FERC rate filings. The new depreciation accrual rates were reflected in IPC s OATT rates beginning October 1, 2009.

Advanced Metering Infrastructure (AMI)

The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. In the future, the system will support enhancements to allow for time-variant rates, perform remote connects and disconnects, and collect system operations data enhancing outage management, reliability efforts and demand-side management options.

IPC filed AMI evaluation and deployment reports with the IPUC on May 1 and August 31, 2007, in compliance with an IPUC order. Consistent with the implementation plan contained in those reports, IPC entered into a number of contracts for materials and resources that allowed for the AMI implementation to commence in late 2008. IPC intends to install this technology for approximately 99 percent of its customers and is on pace to complete the installations by the end of 2011 as scheduled.

Idaho: On August 5, 2008, IPC filed an application with the IPUC requesting a CPCN for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC approved IPC s application on February 12, 2009. In its application, IPC estimated the three-year investment in AMI to be $70.9 million. In an April 7, 2009, order, the IPUC clarified that IPC can expect in the ordinary course of events, to include in rate base the prudent capital costs of deploying AMI as it is placed in service up to the capital cost commitment estimate of $70.9 million. The IPUC also clarified, as requested by IPC, that it does not anticipate that the immediate savings derived from the implementation of AMI throughout IPC s service territory will eliminate or wholly offset the increase in IPC s revenue requirement caused by the authorized depreciation period.

On March 13, 2009, IPC filed an application with the IPUC for authority to increase its rates due to the inclusion of AMI investment in rate base. The filing requested inclusion of the investments already made for the installation of AMI throughout IPC s service territory, and those investments that would be made during a June 1, 2009, through May 31, 2010 test year. IPC requested a first year revenue requirement of $11.2 million in the Idaho jurisdiction effective June 1, 2009, for service provided on or after that date. In its calculations, IPC reflected the reduction in investment and the accelerated depreciation costs related to the removal of current metering equipment, as well as changes in operating expenses that accompany the changes in plant investment.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on IPC s actual investment in AMI to date, annualized through December 31, 2009, rather than IPC s proposed test year. The IPUC also allowed IPC to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. The actual depreciation expense for fiscal year 2009 will occur over seven months totaling $6.2 million. IPC has recorded $3.5 million of this amount through September 30, 2009.

Oregon: On October 3, 2008, IPC filed an application with the OPUC requesting authority to accelerate the depreciation and recovery of existing meters in the Oregon jurisdiction over an 18-month period beginning January 2009. The OPUC approved IPC s request on December 30, 2008. IPC s AMI deployment schedule calls for the replacement of the Oregon service-territory meters around October 2010. The existing meters will be fully depreciated prior to their removal from service. The filing estimated the balance of plant in service at December 31, 2008, attributable to the existing meters to be $1.4 million. The approval of this application results in an increase of $0.8 million for 2009 in both rates and depreciation expense. This increase is partially offset by the reduced depreciation rates discussed above in Depreciation Filings. Combined, the two adjustments result in a $0.4 million net increase to annual depreciation during the period of accelerated recovery.

Deferred Pension Expense

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the pension plan. On March 20, 2007, IPC requested that the IPUC clarify that IPC can consider future cash contributions made to the pension plan a recoverable cost of service. On June 1, 2007, the IPUC issued an order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer pension expense as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. The regulatory asset created by this order is expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. IPC deferred $22 million of pension expense in the first nine months of 2009 and has deferred $33 million since the order became effective in 2007. IPC does not receive a carrying charge on the deferral balance.

On October 20, 2009, IPC filed an application with the IPUC requesting the implementation of a pension recovery method that includes a forecast and a true-up. Under the proposed mechanism IPC will make an annual filing with the IPUC by April 7 of each year with a forecast test year of March 1 through February 28 and rates to be in effect June 1 through May 31. The first filing, to be made by April 7, 2010, will include a forecast of cash contributions to be made to the plan from March 1, 2010 through February 28, 2011 for inclusion in rates during the period from June 1, 2010 through May 31, 2011. Each subsequent year, the filing will include the forecast for the next year and a true-up of the difference between actual contributions and collections during the prior year test period. IPC has requested that this application be processed under modified procedure.

The recovery method IPC requested is intended to meet the conditions for continued deferral of pension-related amounts as regulatory assets. IPC s regulatory assets for deferred pension expense and unfunded pension liability were approximately $33 million and $92 million, respectively, at September 30, 2009.

Idaho OATT Shortfall Filing

For Idaho jurisdictional revenue requirement determinations, revenues from third parties (non-state jurisdictional) received through the OATT, referred to as revenue credits, are a direct offset to IPC s overall revenue requirement. In the last two general rate cases, IPC included an estimate of OATT revenues from third parties based on the forecasted OATT rate less a reserve. However, as discussed below in Federal Regulatory Matters - OATT , the FERC order issued on January 15, 2009 had a significant impact on actual third-party transmission revenues IPC received from June 2006 to date, resulting in the overstating of the revenue credits in the Idaho jurisdictional revenue requirement authorized by the IPUC. On July 20, 2009, IPC filed a request with the IPUC for authorization to defer $8.1 million in costs associated with the difference between the revenue credits and the amount of OATT revenues IPC has received since March 2008 and expects to receive through May 2010. Included in the filing are $4.3 million for the period March 1, 2008 through January 31, 2009, the effective period of the February 28, 2008, general rate case order, and $3.8 million estimated for the period February 1, 2009 through May 31, 2010, the expected effective period of the January 30, 2009 general rate case order. IPC requested to amortize the unrecovered transmission revenues on a straight-line basis over a three-year period beginning June 1, 2010 and to receive a carrying charge on the balance until rate recovery begins. The application is proceeding under modified procedure. IPC has filed a request for rehearing of the FERC order and is taking additional measures to address the revenue shortfall. If the FERC issues are resolved in IPC s favor, IPC will reduce the deferral. On September 29, 2009, the IPUC Staff filed comments. Both parties have agreed to reduce the calculation of the total deferral from $8.1 million to $4.7 million to reflect transmission rate increases that became effective after IPC filed its application.

Rule H Modifications

On October 30, 2008, IPC filed an application seeking authority to modify its Rule H tariff, which governs the allocation between new customers and IPC of the costs of installing or altering distribution equipment to serve new customers. The application requested an increase to the charges for new service attachments, distribution line installations and alterations in order to shift more of the cost burden to new customers requesting construction for these services. On July 1, 2009 the IPUC approved the application with minor modifications. The IPUC also clarified that IPC should not bear the costs incurred to relocate distribution facilities located in public rights-of-way when the relocation is ordered for the benefit of a private development. These changes to Rule H are effective on November 1, 2009. The IPUC has received requests for reconsideration from four parties. On August 19, 2009, the IPUC granted in part several intervenors petitions for reconsideration. Oral argument was held on October 13, 2009, and a technical hearing was held on October 20, 2009.

The case presents two distinct sets of issues on reconsideration: (1) the appropriate calculation of customer allowances associated with new service attachments and (2) whether the IPUC has jurisdiction to authorize charges to third parties for relocations in public road rights-of-way.

Federal Regulatory Matters

The Bonneville Power Administration Residential Exchange Program: The Pacific Northwest Electric Power Planning and Conservation Act of 1980, through the Residential Exchange Program, has provided access to the benefits of low-cost federal hydroelectric power to residential and small farm customers of the region s investor-owned utilities (IOUs). The program is administered by the Bonneville Power Administration (BPA). Pursuant to agreements between the BPA and IPC, benefits from the BPA were passed through to IPC s Idaho and Oregon residential and small farm customers in the form of electricity bill credits.

On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit ruled that the settlement agreements entered into between the BPA and the IOUs (including IPC) are inconsistent with the Northwest Power Act. On May 21, 2007, the BPA notified IPC and six other IOUs that it was immediately suspending the Residential Exchange Program payments that the utilities pass through to their residential and small farm customers in the form of electricity bill credits. IPC took action with both the IPUC and the OPUC to reduce the level of credit on its customers bills to zero, effective June 1, 2007.

Since that time IPC has been working with the other northwest IOUs and consumer-owned utilities, northwest state public utility commissions and the BPA to craft an agreement so that residential and small farm customers of IPC can resume sharing in the benefits of the federal Columbia River power system. However, the matter has yet to be resolved. The BPA has initiated several public processes, which ultimately will determine whether benefits will be restored to IPC customers. The most significant of these processes are the establishment of new residential purchase and sales agreements (RPSAs) and the WP-07 rate case. The RPSAs are intended to replace the settlement agreements invalidated by the court and to provide the structure through which benefits will be shared with the residential and small farm customers of IOUs. The WP-07 supplemental case addresses the calculation of overpayment (if any) of benefits to customers of the IOUs under the settlement agreements and whether those overpayments must be repaid by a reduction to future benefits.

The BPA issued a Final Record of Decision (ROD) on September 4, 2008, to establish new RPSAs and another ROD on September 22, 2008 in the WP-07 case. Together the RODs continue to reflect no residential exchange benefits for IPC s residential and small farm customers in the foreseeable future. IPC has filed petitions for review in the U.S. Court of Appeals for the Ninth Circuit challenging both RODs the RPSAs on November 26, 2008, and the WP-07 case on December 16, 2008, as have other IOUs and other regional customers of the BPA and state utility commissions. Additionally, the BPA issued a Final ROD in its WP-10 rate case on July 21, 2009, which establishes BPA power rates for fiscal years 2010-2011. The WP-10 ROD incorporates many of the determinations that the BPA made in the WP-07 ROD. IPC and other IOUs have filed petitions for review in the U.S. Court of Appeals for the Ninth Circuit challenging the WP-10 ROD.

A mediation process within the Ninth Circuit Court was initiated in an attempt to settle issues raised in the appeals of the WP-07 case. Three meetings were held in February and March 2009 between the BPA, IOUs, other regional customers of the BPA and state utility commissions to determine if there is common ground for an overall settlement of the Residential Exchange Program issues. The mediation effort was unsuccessful, and the court established briefing schedules with initial briefs filed by August 19, 2009, and briefing to conclude on February 26, 2010. Oral argument has not yet been scheduled.

A renewed settlement effort was initiated in July 2009 in an attempt to resolve the residential exchange program issues. Three settlement conferences took place during August and September and a fourth is scheduled for November 2009.

IPC will continue its efforts to secure future benefits for its customers. Since these benefits were passed through to IPC s customers, the outcome of this matter is not expected to have an effect on IPC s financial condition or results of operations.

OATT: On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing, IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on financial and operational data IPC is required to file annually with the FERC in its Form 1. The formula rate request included a rate of return on equity of 11.25 percent. IPC s filing was opposed by several affected parties. Effective June 1, 2006, the FERC accepted IPC s proposed new rates, subject to refund pending the outcome of the hearing and settlement process.

On August 8, 2007, the FERC approved a settlement agreement by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates that were in existence before the implementation of OATT in 1996 (Legacy Agreements). This settlement reduced IPC s proposed new rates and, as a result, approximately $1.7 million collected in excess of the settlement rates between June 1, 2006, and July 31, 2007, was refunded with interest in August 2007. As part of the settlement agreement, the FERC established an authorized rate of return on equity of 10.7 percent.

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements, which would have further reduced the new transmission rates. IPC, as well as the opposing parties, appealed the Initial Decision to the FERC. If implemented, the Initial Decision would have required IPC to make additional refunds, of approximately $5.4 million (including $0.4 million of interest) for the June 1, 2006, through December 31, 2008, period. IPC previously reserved this entire amount.

On January 15, 2009, the FERC issued an Order on Initial Decision (FERC Order), which upheld the Initial Decision of the ALJ in most respects, but modified the Initial Decision in one respect that is unfavorable to IPC. The decision required IPC to reduce its transmission service rates to FERC jurisdictional customers. Furthermore, IPC was required to make refunds to FERC jurisdictional transmission customers in the total amount of $13.3 million (including $1.1 million in interest) for the period since the new rates went into effect in June 2006. Based on the FERC Order, IPC reserved an additional $7.9 million (including $0.7 million in interest) in the fourth quarter of 2008, bringing the total reserve amount to $13.3 million. Prior to the FERC Order, the FERC jurisdictional transmission revenues (net of the $5 million reserve) recorded in the last seven months of 2006, all of 2007 and 2008 were $8.1 million, $13.3 million and $15.8 million, respectively. Under the FERC Order, the transmission revenues would have been $6.4 million in the last seven months of 2006, $11 million in 2007 and $12.6 million in 2008. Refunds were made on February 25, 2009.

IPC filed a request for rehearing with the FERC on February 17, 2009. IPC believes that the treatment of the Legacy Agreements conflicts with precedent. The rehearing request asserts that the FERC order is in error by: (1) requiring IPC to include the contract demands associated with the Legacy Agreements in the OATT formula rate divisor rather than crediting the revenue from the Legacy Agreements against IPC s transmission revenue requirement; (2) concluding that IPC must include the contract demands associated with the Legacy Agreements rather than the customers coincident peak demands; (3) concluding that the transmission rate contained in one or more of the Legacy Agreements was not a discounted rate; (4) failing to consider the non-monetary benefits received by IPC from the Legacy Agreements; (5) concluding that the services provided under the Legacy Agreements are firm services and therefore should be handled for rate purposes in the same manner as firm services under the OATT; and (6) failing to affirm the rate treatment that has been used for the Legacy Agreements for approximately 30 years. On March 18, 2009, the FERC issued a tolling order that effectively relieves it from acting on the request for reconsideration for an indefinite time period. IPC cannot predict when the FERC will rule on the request for rehearing or the outcome of this matter.

Amended Legacy Agreements: Subsequent to the January 15, 2009 FERC Order, IPC has sought to mitigate the resulting revenue shortfall by revising certain of the Legacy Agreements as provided for in the agreements.

On April 3, 2009, IPC notified PacifiCorp that it was terminating its provision of a portion of the services that it provides under the Restated Transmission Service Agreement (RTSA), a Legacy Agreement effective June 12, 2009. IPC made a filing with the FERC on April 13, 2009 submitting revised rate schedule sheets. The FERC accepted the revised rate schedule sheets by letter order on May 14, 2009. On June 12, 2009, IPC submitted a filing for the purpose of replacing the terminated contract services with OATT service, effective June 13, 2009. An amended RTSA between IPC and PacifiCorp and three long term service agreements were filed to provide for the OATT service. As calculated in the filings, the estimated net transmission revenue increase for the period June 13, 2009 through June 12, 2010 is approximately $3.2 million. The FERC accepted IPC s filing, effective June 13, 2009, by letter order on July 28, 2009.

On June 19, 2009, IPC submitted a filing to increase rates under the Agreement for Interconnection and Transmission Services (ITSA) contract, another Legacy Agreement between IPC and PacifiCorp. The filing requested an increase of rates to the level paid by OATT customers for Point to Point service and an August 19, 2009, effective date. As calculated in the filing, the estimated net transmission revenue increase for the period September 1, 2009 through August 31, 2010 is approximately $3.9 million. PacifiCorp has intervened in the case and on July 10, 2009 filed a motion to suspend the case for five months and pursue settlement or go to hearing. On August 18, 2009, the FERC accepted IPC s filing and suspended it, setting it for settlement judge procedures and hearing. IPC is collecting the new rates subject to refund and has reserved the entire increase pending settlement. A settlement conference was held on October 7, 2009, and another is scheduled for November 18, 2009. Settlement discussions are ongoing.

2009 OATT: On August 28, 2009, IPC filed its informational filing with the FERC that contains the annual update of the formula rate based on the 2008 test year. The new rate included in the filing was $15.83 per kW-year, an increase of $2.02 per kW-year, or 14.6 percent. New rates were effective October 1, 2009.

2008 OATT**:** On August 28, 2008, IPC filed its informational filing with the FERC that contained the annual update of the formula rate based on the 2007 test year. The rate included in the filing was $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. New rates were effective October 1, 2008. IPC subsequently adjusted its rates to $13.81 per kW-year in compliance with the January 15, 2009, order.

FERC Compliance Program: The FERC issued Policy Statements on Enforcement in 2005 and 2008 and a Policy Statement on Compliance in 2008, which encourage companies to self-report to the FERC matters that constitute or may constitute violations of the Federal Power Act, the Natural Gas Act, the Natural Gas Policy Act and the requirements of FERC rules, regulations, orders and tariffs. The Policy Statements identify self-reporting as a factor the FERC will consider in determining the proper remedy for a violation and emphasize the role compliance programs play in identifying and correcting violations and in evaluating whether and the extent to which penalties may be imposed. IPC has implemented a compliance program to ensure that its operations conform to the FERC s requirements and to provide a means of identifying and if warranted, self-reporting on a regular basis any such matters to the FERC. IPC also self-reports matters relating to transmission reliability standards to the Western Electricity Coordinating Council (WECC). In 2007, FERC Order No. 693 approved mandatory reliability standards developed by the North American Electric Reliability Corporation. The WECC, a regional electric reliability organization, has responsibility for compliance and enforcement of these standards. As part of its compliance program, IPC has reported compliance issues relating to the FERC s Standards of Conduct and IPC s Open Access Transmission Tariff to the FERC, as well as matters relating to reliability standards to the WECC. Some of these matters have been resolved, while others are being reviewed by the FERC or the WECC. IPC is unable to predict what action if any the FERC or the WECC will take with regard to the unresolved matters. IPC plans to continue its policy of using its compliance program to reduce potential violations and to self-report matters regularly to the FERC and the WECC.

Public Utility Regulatory Policies Act of 1978

As mandated by the enactment of PURPA and the adoption of avoided cost rates by the IPUC and the OPUC, IPC has entered into contracts for the purchase of energy from a number of private developers. Under these contracts, IPC is required to purchase all of the output from the facilities located inside the IPC service territory. For projects located outside the IPC service territory, IPC is required to purchase the output that IPC has the ability to receive at the facility s requested point of delivery on the IPC system. The IPUC jurisdictional portion of the costs associated with CSPP contracts are fully recovered through base rates and the PCA. For IPUC jurisdictional contracts, projects that generate up to ten average MW of energy on a monthly basis are eligible for IPUC Published Avoided Costs for up to a 20-year contract term. The OPUC jurisdictional portion of the costs associated with CSPP contracts is recovered through general rate case filings. For OPUC jurisdictional contracts, projects with a nameplate rating of up to ten MW of capacity are eligible for OPUC Published Avoided Costs for up to a 20-year contract term. The Published Avoided Cost is a price established by the IPUC and the OPUC to estimate IPC s cost of developing additional generation resources. If a PURPA project does not qualify for Published Avoided Costs, then IPC is required to negotiate the terms, prices and conditions with the developer of that project. These negotiations reflect the characteristics of the individual projects (i.e., operational flexibility, location and size) and the benefits to the IPC system and must be consistent with other similar energy alternatives.

On March 12, 2009, the IPUC increased the Published Avoided Cost rates. For example, the rate for a 20 year levelized 2009 contract increased from $69.54/MWh to $88.92/MWh. This increase will result in the continuation of a favorable climate for PURPA project development, and may require IPC to enter into additional PURPA agreements. The requirement to enter into additional PURPA agreements may result in IPC acquiring energy at above wholesale market prices and at times when a surplus already exists as well as requiring additional operational integration costs, thus increasing costs to its customers.

Integrated Resource Plan

IPC s integrated resource planning process forecasts IPC s load and resource situation for the next 20 years, analyzes potential supply-side and demand-side options and identifies near-term and long-term actions. IPC s most recent IRP was completed in 2006 and the IRP is typically updated every two years. In preparing an IRP, IPC works with the IRP Advisory Council which consists of representatives from various customer segments, governmental and regulatory agencies, and environmental and other public interest groups. Meetings with the IRP Advisory Council are open to the public and are typically held on a monthly basis during the process of preparing an IRP.

At the request of the IPUC, the submittal of IPC s next IRP was delayed until June 2009 in order for IPC to align the submittal of its next IRP with the IRP s of other Idaho utilities. In June 2008, IPC filed the 2008 IRP Update as an informational filing with the IPUC and OPUC. IPC also prepared and filed the IRP Addendum with the OPUC in February 2009. The IRP Addendum specifically addressed the need for the Boardman to Hemingway Transmission Project and was later withdrawn due to public opposition to proposed routes and also to allow IPC to analyze the project in the 2009 IRP process.

IPC began preparing the 2009 IRP in August 2008. However, in light of the economic recession that developed since September 2008 when IPC prepared the load forecast being used for the 2009 IRP, and in response to the OPUC s desire for additional analysis regarding the Boardman to Hemingway Transmission Project, in April 2009 IPC filed a request for an extension with the IPUC and OPUC to delay the filing of the 2009 IRP until December 2009. The IPUC and OPUC approved IPC s request for an extension. IPC intends to complete and file the 2009 IRP in December 2009.

During the time between resource plan filings, the public and regulatory oversight of the activities identified in the IRP allows for discussion and adjustment of the IRP as warranted. IPC continues to analyze and evaluate the resource plan and make periodic adjustments and corrections to reflect changes in technology, economic conditions, anticipated resource development and regulatory requirements. In addition, load and resource forecasts are routinely updated as described earlier in RESULTS OF OPERATIONS Utility Operations. Each of the sections below provides an update of items identified in the resource planning process.

Geothermal RFPs:

Although the 2008 Geothermal RFP for 50-100 MW did not result in IPC acquiring additional geothermal energy, IPC continues to work with project developers capable of delivering energy to its service area. IPC also continues to monitor developments in geothermal technology and is hopeful geothermal energy will become an economic and readily available resource for its customers. IPC is in the process of negotiating for potential long-term power purchase agreements with geothermal developers.

Combined Heat and Power (CHP) RFP: The 2006 IRP included 50 MW of CHP coming on-line in 2010. In April 2008, IPC solicited its large industrial customers to determine the level of interest in CHP development. While the level of interest in CHP development has been less than anticipated in the 2006 IRP, IPC continues to work with parties to explore CHP development opportunities. IPC is also currently working with the State of Idaho s Office of Energy Resources to determine the feasibility of developing a combined heat and power project in IPC s service area.

Wind RFP: The 2006 IRP included 150 MW of wind generation coming on-line in 2012. In May 2009, IPC issued an RFP for up to 150 MW of wind generation to come on-line no later than the end of 2012. IPC accelerated the release of the wind RFP to take advantage of the benefits offered in the ARRA (the economic stimulus package). Proposals were received in June 2009. IPC expects to enter into a contract with one of the bidders and file the contract with the IPUC in the first quarter of 2010.

Relicensing of Hydroelectric Projects

IPC, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses last for 30 to 50 years depending on the size, complexity, and cost of the project. IPC is actively pursuing the relicensing of the Hells Canyon Complex (HCC) and Swan Falls projects.

The relicensing costs are recorded and held in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges will be 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 \$114 million and \$4 million for HCC and Swan Falls, respectively, were included in construction work in progress at September 30, 2009.

The IPUC authorized IPC to include in rates approximately \$6.8 million (\$10.6 million grossed up for income taxes) of AFUDC relating to the HCC relicensing project. This became effective February 1, 2009, and IPC collected approximately \$3.3 million in the third quarter and \$7.3 million year-to-date. Collecting these amounts in current rates will reduce future rates related to obtaining the new license once the accumulated relicensing costs are placed in service. Further discussion is provided above in Idaho Rate Cases 2008 General Rate Case.

Hells Canyon Complex: The most significant ongoing relicensing effort is the HCC, which provides approximately 68 percent of IPC s hydroelectric generating nameplate capacity and 36 percent of its total generating nameplate capacity. In July 2003, IPC filed an application for a new license in anticipation of the July 2005 expiration of the then-existing license. IPC is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until the new license is issued.

Consistent with the requirements of the National Environmental Policy Act of 1969, as amended (NEPA), the FERC Staff issued on August 31, 2007, a final environmental impact statement (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 IPC s proposed operation of the HCC. IPC has reviewed the final EIS and is developing comments for filing with the FERC. However, certain portions of the final EIS, involve issues that may be influenced by the 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 as discussed below. IPC anticipates filing comments to the final EIS after resolution of these issues.

In conjunction with the issuance of the final EIS, on September 13, 2007, the FERC requested formal consultation under the Endangered Species Act (ESA) with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS) regarding the effect of HCC relicensing on several aquatic and terrestrial species listed as threatened under the ESA. However, formal consultation has not yet been initiated and NMFS and USFWS continue to gather and consider information relative to the effect of relicensing on relevant species. IPC continues to cooperate with the USFWS, the NMFS and the FERC in an effort to address ESA concerns.

Because the HCC is located on the Snake River where it forms the border between Idaho and Oregon, IPC has filed Water Quality Certification Applications, required under section 401 of the Clean Water Act, 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. Temperature and other water quality issues are of interest to various federal and state agencies, Native American tribes, and other parties who may provide input to the states   certification process. IPC continues to work with Idaho and Oregon to ensure that any discharges from the HCC will comply with the necessary state water quality standards so that appropriate water quality certifications can be issued for the project.

The FERC is expected to issue a license order for the HCC once the ESA consultation and the section 401 certification processes are completed.

Swan Falls Project: The license for the Swan Falls hydroelectric project expires in June 2010. In June 2008, IPC filed a license application with the FERC. On January 9, 2009, the FERC issued a scoping document giving notice of scheduled scoping meetings, soliciting scoping comments and of its intent to prepare an EIS pursuant to the NEPA. FERC held scoping meetings on February 10 and 11, 2009. On May 5, 2009, FERC issued Scoping Document 2 for the project, advising that based on the scoping meetings and comments received that staff will prepare an EIS, which the FERC will use to determine whether, and under what conditions, to issue a new hydropower license for the project. On June 16, 2009, FERC issued its Notice of Application Ready for Environmental Analysis and Soliciting Comments, Recommendations, Terms and Conditions, and Prescriptions. The deadline for filing comments, recommendations, terms and conditions, and prescriptions was August 15, 2009. Filings were made by the United

States Fish and Wildlife Service and State of Idaho. The FERC expects to complete the EIS in 2010.

Section 401 of the Clean Water Act requires that an applicant for a federal license to conduct an activity that results in any discharge to navigable waters must provide the licensing agency with a certification from the state in which the discharge occurs that the discharge will comply with applicable water quality standards. In conformance with that section, on June 6, 2008, IPC filed an application with the Idaho Department of Environmental Quality (IDEQ) for section 401 water quality certification. On April 1, 2009, the IDEQ issued public notice, seeking public comment on a draft section 401 certification for the project. No public comments were submitted and the IDEQ issued the section 401 certification on May 4, 2009.

Shoshone Falls Expansion: On August 17, 2006, IPC filed a license amendment application with the FERC, which would allow IPC to upgrade the Shoshone Falls project from 12.5 MW to 62.5 MW. The license amendment is expected to be issued in 2010. In conjunction with the license amendment application, IPC has filed a water rights application with the Idaho Department of Water Resources (IDWR).

LEGAL AND ENVIRONMENTAL ISSUES:

Western Energy Proceedings at the FERC: Throughout this report, the term western energy situation is used to refer to the California energy crisis that occurred during 2000 and 2001, and the energy shortages, high prices and blackouts in the western United States. High prices for electricity in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds. Some of these proceedings (the western energy proceedings) remain pending before the FERC or on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

There are pending in the Ninth Circuit approximately 200 petitions for review of numerous FERC orders regarding the western energy situation, including the California refund proceeding and show cause orders with respect to contentions of market manipulation. Decisions in these appeals may have implications with respect to other pending cases, including those to which IDACORP, IPC or IE are parties. IDACORP, IPC and IE intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters, except as otherwise stated below, or estimate the impact they may have on their consolidated financial positions, results of operations or cash flows.

<u>California Refund:</u> This proceeding originated with an effort by agencies of the State of California and investor-owned utilities in California to obtain refunds for a portion of the spot market sales from sellers of electricity into California markets from October 2, 2000, through June 20, 2001. In April 2001, the FERC issued an order stating that it was establishing a price mitigation plan for sales in the California wholesale electricity market. The FERC s order also included the potential for directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. In July 2001, the FERC initiated the California refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. After evidentiary hearings, the FERC issued an order on refund liability on March 26, 2003, and later denied the numerous requests for rehearing. The FERC also required the California Independent System Operator (Cal ISO) to make a compliance filing calculating refund amounts. That compliance filing has been delayed on a number of occasions and has not yet been filed with the FERC.

IE and other parties petitioned the Ninth Circuit for review of the FERC s orders on California refunds. As additional FERC orders have been issued, further petitions for review have been filed by potential refund payors, including IE, potential refund recipients and governmental agencies. These cases have been consolidated before the Ninth Circuit. Since the initiation of these cases, the Ninth Circuit has convened a number of case management proceedings to organize these complex cases, while identifying and severing discrete cases that can proceed to briefing and decision and staying action on all of the other consolidated cases.

In its October 2005 decision in the first of the severed cases, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. In its August 2006 decision in the second severed case, the Ninth Circuit ruled that all transactions that occurred within the

California Power Exchange (CalPX) and the Cal ISO markets were proper subjects of the refund proceeding, refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date, and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. These latter aspects of the decision exposed sellers to increased claims for potential refunds. A number of public entities filed petitions for panel rehearing in June 2007 and certain marketers filed petitions for rehearing and rehearing en banc in November 2007. Those requests were denied by the Ninth Circuit on April 6, 2009. The Ninth Circuit issued a mandate on April 15, 2009, thereby officially returning the cases to the FERC for further action consistent with the court s decision.

In 2005, the FERC established a framework for sellers wanting to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and IPC made such a cost filing but it was rejected by the FERC in March 2006. IE and IPC requested rehearing of that rejection, but, consistent with obligations established in a settlement which is described in the following paragraph, IE and IPC withdrew that request for rehearing to the extent it pertained to the disputes about the cost filing between IE and IPC and parties that had joined the settlement. On June 18, 2009 FERC issued an order with respect to the cost filings of other sellers and in that order also stated that it was not ruling on the IE and IPC request for rehearing because it had been withdrawn. On July 8, 2009 IE and IPC sought further rehearing pointing out to the FERC that the withdrawal pertained only to the parties with whom IE and IPC had settled. On June 18, 2009, in a separate order, the FERC also ruled that net refund recipients in the California refund proceeding were responsible for the costs associated with all cost filings. Most of the parties that joined the IE and IPC settlement described below were net refund recipients, but until the Cal ISO completes its refund calculations it is uncertain whether any parties who opted not to join the settlement are net refund recipients. If there are no such parties, then the requests for rehearing will be moot. On August 7, 2009 the FERC issued an order extending the time for its consideration of the IE and IPC request for rehearing. IE and IPC are unable to predict how or when the FERC might rule on their requests for rehearing, but their effect is confined to obligations of IE and IPC to the minority of market participants that opted not to join the settlement described below. Accordingly, IE and IPC believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC settling matters encompassed by the California refund proceeding, as well as other FERC proceedings and investigations relating to the western energy matters, including IE s and IPC s cost filing and refund obligation. A number of other parties, representing a small minority of potential refund claims, chose to opt out of the settlement. Under the terms of the settlement, IE and IPC assigned $24.25 million of the rights to accounts receivable from the Cal ISO and CalPX to the California Parties to pay into an escrow account for refunds to settling parties. Amounts from that escrow not used for settling parties and $1.5 million of the remaining IE and IPC receivables that are to be retained by the CalPX are available to fund, at least partially, payment of the claims of any non-settling parties if they prevail in the remaining litigation of this matter. Any excess funds remaining at the end of the case are to be returned to IE and IPC. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement. In addition, the California Parties released IE and IPC from other claims stemming from the western energy market dysfunctions. The FERC approved the Offer of Settlement on May 22, 2006.

Market Manipulation: As part of the California refund proceeding discussed above and the Pacific Northwest refund proceeding discussed below, the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered more than 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming (gaming) or other forms of proscribed market behavior in concert with another party (partnership) in violation of the Cal ISO and CalPX Tariffs. In 2004, the FERC dismissed the partnership show cause proceeding against IPC. Later in 2004, the FERC approved a settlement of the gaming proceeding without finding of wrongdoing by IPC.

The orders establishing the scope of the show cause proceedings are presently the subject of review petitions in the Ninth Circuit. In addition to the two show cause orders, on June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale markets for the time period May 1, 2000, through October 1, 2000, to enable it to review evidence of economic withholding of generation. IPC, along with more than 60 other market participants, responded to the FERC data requests. The FERC terminated its investigations as to IPC on May 12, 2004. Although California government agencies and California investor-owned utilities have appealed the FERC s termination of this investigation as to IPC and more than 30 other market participants, the claims regarding the conduct encompassed by these investigations were released by these parties in the California refund settlement discussed above. IE and IPC are unable to predict the outcome of these matters, but believe that the releases govern any potential claims that might arise and that this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding separate from the California refund proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. In late 2001, a FERC Administrative Law Judge concluded that the contracts at issue were governed by the substantially more strict *Mobile-Sierra* standard of review rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. After the Judge s recommendation was issued, the FERC reopened the proceeding to allow the submission of additional evidence directly to the FERC related to alleged manipulation of the power market by market participants. In 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit and in 2007 the Ninth Circuit issued an opinion, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit s opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency s conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources (CDWR) in the proceeding. A number of parties sought rehearing of the Ninth Circuit s decision. On April 9, 2009, the Ninth Circuit denied the petitions for rehearing and rehearing en banc. The Ninth Circuit issued a mandate on April 16, 2009, thereby officially returning the case to the FERC for further action consistent with the court s decision. On September 4, 2009 IE and IPC joined with a number of other parties in a joint petition for a writ of certiorari to the U.S. Supreme Court.

On May 22, 2009 the California Parties filed a motion with the FERC to sever the CDWR sales from the remainder of the Pacific Northwest proceedings and to consolidate the CDWR sales portion of the Pacific Northwest case with ongoing proceedings in cases that IE or IPC have settled and with a new complaint filed on May 22, 2009 by the California Attorney General against parties with whom the California Parties have not settled (Brown Complaint). On August 4, 2009, IE and IPC, along with a number of other parties, filed their opposition to the motion of the California Parties. Many other parties also filed positions in response to the motion of the California Parties. Also on August 4, 2009 the City of Tacoma, Washington and the Port of Seattle, Washington filed a motion with the FERC in connection with the California refund proceeding, the Lockyer remand pending before the FERC (involving claims of failure to file quarterly transaction reports with the FERC, from which IE and IPC previously were dismissed), the Brown Complaint and the Pacific Northwest refund remand proceeding. This latter motion asks the FERC (1) to make findings on a summary basis that the entire West-wide wholesale electricity market, including the Pacific Northwest, was affected by market manipulation and that, as a result, jurisdictional sellers rates exceeded just and reasonable levels throughout the Western energy crisis of 2000 -2001, to grant market-wide refunds to all purchasers for amounts collected in excess of a just and reasonable price and to establish procedures to determine specific refund obligations applicable to sellers or, in the alternative, (2) to institute an evidentiary hearing and establish related procedures to respond to the remand proceedings ordered by the Ninth Circuit in Port of Seattle, Washington v. FERC that would include supplemental evidence filed with the motion and consideration of claimed violations of Market Based Rate Tariffs from January 1, 2000 through June 20, 2001, thereby expanding the scope of potential refunds to a period beginning prior to December 25, 2000. On October 5, 2009, IE and IPC joined with a number of other sellers in the Pacific Northwest markets during 2000 and 2001 in filing an answer opposing the motion of the City of Tacoma and the Port of Seattle. Other parties also filed answers opposing the motion. IE and IPC intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters or estimate the impact these matters may have on their consolidated financial positions, results of operations or cash flows.

On June 26, 2008, the U.S. Supreme Court issued a decision in Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County (No. 06-1457) (Snohomish), a case regarding a FERC decision not to require re-pricing of certain long-term contracts. In Snohomish, the Supreme Court revisited and clarified the *Mobile-Sierra* doctrine in the context of fixed-rate, forward power contracts. At issue was whether, and under what circumstances, the FERC could modify the rates in such contracts on the grounds that there was a dysfunctional market at the time the contracts were executed. In its decision, the Supreme Court disagreed with many of the conclusions reached in an earlier decision by the Ninth Circuit and upheld the application of the *Mobile-Sierra* doctrine even in cases in which it is alleged that the markets were dysfunctional. The Supreme Court nonetheless directed the return of the case to the FERC to (i) consider whether the challenged rates in the case constituted an excessive burden on consumers either at the time the contracts were formed or during the term of the contracts relative to the rates that could have been obtained after elimination of the dysfunctional market and (ii) clarify whether it found the evidence inadequate to support a claim that one of the parties to a contract under consideration engaged in unlawful market manipulation that altered the playing field for the particular contract negotiations that is, whether there was a causal connection between allegedly unlawful activity and the contract rate. On November 3, 2008, the Ninth Circuit vacated its earlier decision and remanded the case to the FERC for further proceedings consistent with the Supreme Court s decision. On December 18, 2008, the FERC issued its order on remand, establishing settlement proceedings and paper hearing procedures to supplement the record and permit it to respond to the questions specified by the Supreme Court. Those proceedings are currently being held in abeyance to allow settlement efforts to proceed.

The Supreme Court s decision is expected to have general implications for contracts in the wholesale electric markets regulated by the FERC, and particular implications for forward power contracts in such markets. The Snohomish decision upholds the application of the *Mobile-Sierra* doctrine to fixed-rate, forward power contracts even in allegedly dysfunctional markets. IE and IPC have asserted the *Mobile-Sierra* doctrine in the Pacific Northwest proceeding, involving spot market contracts in an allegedly dysfunctional market.

On April 27, 2009, the U.S. Supreme Court granted a writ of certiorari in *NRG Power Marketing, LLC vs. Maine Public Utilities Commission*, a case in which neither IE nor IPC is a party. At issue is the applicability of the *Mobile-Sierra* doctrine to persons that are not parties to a contract that otherwise is governed by the doctrine. Argument is scheduled for November 3, 2009.

IDACORP, IPC and IE are unable to predict how the FERC will rule on Snohomish on remand or how the Supreme Court will decide the issues in the *NRG* case or how these decisions may affect the outcome of the Pacific Northwest proceeding.

Sierra Club Lawsuit-Bridger: IPC continues to monitor the Sierra Club and the Wyoming Outdoor Council suit against PacifiCorp filed in February 2007 in federal district court in Cheyenne, Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal-fired plant in Sweetwater County, Wyoming. IPC is not a party to this proceeding but has a one-third ownership interest in the plant. PacifiCorp owns a two-thirds interest in and is the operator of the plant. On August 24, 2009, the court granted plaintiffs motion for partial summary judgment that plaintiffs have standing to bring the action but denied the other two motions for summary judgment filed by plaintiffs and PacifiCorp. IPC is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit Boardman: On September 30, 2008, the Sierra Club and four other non-profit corporations filed a complaint against Portland General Electric Company (PGE) in the U.S. District Court for the District of Oregon alleging opacity permit limit violations at the Boardman coal-fired plant located in Morrow County, Oregon. The complaint also alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE s construction and operation of the plant. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant.

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. On September 30, 2009, the court denied most of PGE s motion to dismiss. IPC continues to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

Oregon Trail Heights Fire: On August 25, 2008, a fire ignited beneath an IPC distribution line in Boise, Idaho. It was fanned by high winds and spread rapidly, resulting in one death, the destruction of 10 homes and damage or alleged fire related losses to approximately 30 others. Following the investigation, the Boise Fire Department determined that the fire was linked to a piece of line hardware on one of IPC s distribution poles and that high winds contributed to the fire and its resultant damage.

IPC has received notice of claims from a number of the homeowners and their insurers and while it has continued its investigation of these claims, IPC has reached settlements with a number of the individuals or their insurers who have alleged damages resulting from the fire. IPC is insured up to policy limits against liability for claims in excess of its self-insured retention. IPC has accrued a reserve for any loss that is probable and reasonably estimable, including insurance deductibles, and believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

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

Environmental Issues

The section below summarizes and provides an update of environmental issues as discussed in IDACORP s and IPC s Annual Report on Form 10-K for the year ended December 31, 2008 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009.

Global Climate Change:

Long-term climate change could significantly affect IPC s business in a variety of ways, including but not limited to: (a) changes in temperature and precipitation could affect customer demand, (b) extreme weather events could increase service interruptions, outages, and maintenance costs; (c) the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation, and (d) legislative and/or regulatory developments related to climate change could affect plans and operations including placing restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general. IPC is unable to predict the outcome of these matters or estimate the impact these matters may have on its consolidated financial position, results of operations or cash flows.

On September 17, 2009, IDACORP s and IPC s Board of Directors approved guidelines that established a goal to reduce the carbon dioxide (CO_2) emission intensity of IPC s utility operations. The guidelines are intended to further prepare IPC for potential legislative and/or regulatory restrictions on GHG emissions while minimizing the costs of complying with such restrictions on IPC s customers. The guidelines state:

IPC has established a goal to reduce its resource portfolio s average CO_2 emission intensity for the 2010 through 2013 time period to a level of 10 percent - 15 percent below IPC s 2005 CO_2 emission intensity of 1,194 lbs CO_2/MWh.

Since IPC s CO_2 emission intensity fluctuates with stream flows and production levels of anticipated renewable resource additions, IPC believes an average intensity reduction goal to be achieved over several years is appropriate. Generation from IPC-owned and any renewable resources under contract for which IPC has long-term rights to the Renewable Energy Credits (RECs) will be included in the denominator of this calculation. IPC s progress toward achieving this intensity reduction goal, as well as additional information on IPC s CO_2 emissions, will be reported on the IPC website. Information relating to IPC s CO_2 emissions is also available through IPC s filings with the Carbon Disclosure Project (CDP), an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world.

The guidelines are intended to reduce IPC s CO_2 emission intensity in a manner that minimizes the costs of those restrictions on IPC s customers.

IPC continues to closely track and analyze GHG legislation. The analysis of potential GHG legislation will continue in the ongoing 2009 IRP process, which includes involvement by and input from government, public and environmental organizations. The IRP process forecasts IPC s load and resource situation for the next 20 years, analyzes potential supply-side and demand-side options and identifies near-term and long-term actions. Additional analysis undertaken as part of the IRP process will allow IPC and the other IRP participants to (1) assess how IPC s resource portfolio options can be adjusted to meet potential future federal CO_2 emissions restrictions, (2) evaluate the costs and benefits of such adjustments and (3) determine whether and to what extent the adjustments should be included in IPC s plans for future resource acquisitions under the IRP.

On September 22, 2009, the EPA issued a final rule that requires monitoring and reporting of GHG emissions by a number of entities beginning on January 1, 2010. Most facilities will be required to report annually. Electric generation facilities (including IPC s facilities) already reporting CO_2 emissions under the Clean Air Act (CAA) Acid Rain Program must report CO_2, nitrous oxide and methane emissions to the EPA on a quarterly basis.

On April 24, 2009, the EPA issued a proposed endangerment finding for GHG emissions from mobile sources that was the first step leading to the regulation of GHG emissions from mobile sources under the CAA. On September 28, 2009, the EPA and the Department of Transportation National Highway Traffic Safety Administration issued proposed national GHG emission standards for motor vehicles, covering model years 2012 through 2016. Comments are due November 27, 2009. On September 30, 2009, the EPA proposed a rule which acknowledged that it is required by the CAA to regulate GHG emissions from stationary sources (including IPC s facilities) through both its preconstruction and operating permit programs and proposed to establish an applicability threshold of 25,000 tons of GHGs per year (CO_2 equivalent) for such programs.

A modified version of the American Clean Energy and Security Act of 2009 bill from sponsors Congressmen Henry Waxman (D-CA) and Ed Markey (D-MA) passed the U.S. House of Representatives on June 26, 2009. Senate Environment and Public Works Chairman Barbara Boxer (D-CA) and Senator John Kerry (D-MA) introduced a climate change bill on the Senate floor on September 30, 2009. Although committee meetings and hearings have been scheduled, the timeline for action on the Senate floor remains unclear. In addition, states and regional initiatives (including the Western Climate Initiative) are considering regional market-based mechanisms to reduce GHG emissions.

IPC has posted information about its CO_2 emissions at the environmental section of its website. The website disclosure includes information about IPC s generation resources and IPC s (and its unregulated energy affiliate, Ida-West Energy Company s) emissions ranking for 2006 as one of the 30 lowest CO_2 emitters per megawatt hour produced among the nation s 100 largest electricity producers according to a collaborative report from CERES, the Natural Resources Defense Council, Public Service Enterprise Group and PG&E Corporation using publicly reported 2006 generation and emissions data.

In May 2009, IPC submitted information to the CDP. The CDP posted responding companies information at its website in September 2009. IPC s estimated CO_2 emission intensity (Lbs/MWh) from its generation facilities was 1,150 and 1,097 for 2007 and 2008, respectively.

Renewable Electricity/Portfolio Standards: The American Clean Energy and Security Act of 2009 as passed in the U.S. House of Representatives on June 26, 2009, requires utilities to obtain 15 percent of their electricity from renewable sources by 2020, and reduce demand an additional five percent through conservation and increased energy efficiency. The Senate version, contained in the American Clean Energy Leadership Act of 2009, as reported favorably out of the Senate Committee on Energy and Natural Resources on June 17, 2009, requires electric utilities to meet 15 percent of their electricity sales through renewable sources of energy or energy efficiency by 2021. Resources eligible to meet these standards include wind, solar, geothermal, biomass, landfill gas, ocean, and incremental hydropower (efficiency improvements or new capacity). Both bills recognize the benefits of existing hydroelectric generation by allowing utilities to subtract generation from existing hydroelectric projects from their total sales base prior to calculating the percentage requirement.

In addition, IPC will be required to comply with a ten percent renewable energy portfolio standard (RPS) in Oregon beginning in 2025. No RPS requirement currently exists in Idaho. IPC continues to monitor proposed federal RPS legislation, which if passed could increase capital expenditures and operating costs and reduce earnings and cash flows.

IPC is currently purchasing energy from seven wind projects with a combined nameplate rating of 191.6 MW. IPC also has an additional 244.8 MW of wind generation with signed, and IPUC approved contracts that have not yet been constructed. In addition, IPC has 21.0 MW of wind generation with signed contracts that are awaiting IPUC approval. These projects have not yet been constructed. IPC continues to pursue additional geothermal and combined heat and power (CHP) generation resources with individual developers. Other renewable generation resources anticipated from future CSPP contracts include solar, biomass, CHP and additional wind projects.

Air Quality: IPC owns two natural gas combustion turbine power plants and co-owns three coal-fired power plants that are subject to air quality regulation. IPC continues to actively monitor, evaluate and work on air quality issues pertaining to federal and state mercury emission rules, possible legislative amendment of the Clean Air Act, New Source Review (NSR) permitting, National Ambient Air Quality Standards (NAAQS), and Regional Haze Best Available Retrofit Technology (RH BART). The sulfur dioxide (SO_2) scrubber upgrade project has been completed on Units 2 and 4 at the Jim Bridger plant and scrubber upgrade projects on the other two units at the plant will be completed by the end of 2011.

Regional Haze Best Available Retrofit Technology: In accordance with federal regional haze rules, coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant and the Boardman plant. The two units at the Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule. The Wyoming Department of Environmental Quality (WDEQ) and the Oregon Department of Environmental Quality (ODEQ) are conducting an assessment of emission sources pursuant to a RH BART process. The states are also working on reasonable progress towards a long term strategy beyond RH BART to reduce regional haze in Class I areas to natural conditions by the year 2064.

PacifiCorp submitted a RH BART application for the Jim Bridger plant in January 2007. On June 3, 2009, WDEQ issued a public notice requesting comment from the public on the draft RH BART State Implementation Plan (SIP) arising out of the application. WDEQ has proposed to issue a RH BART air quality permit for modification of Bridger requiring installation of low-NOx burners with separated over-fire air for NOx reduction, and flue gas conditioning to enhance performance of the electrostatic precipitator particulate controls. According to WDEQ, these controls will allow Bridger to meet the EPA s presumptive RH BART emission limits. The plant is already in the process of installing low NOx burners and SO_2 scrubber upgrades that are proposed in the application. IPC expects to spend approximately $22 million between 2009 and 2012 to complete these projects. WDEQ is further proposing to require Bridger Units 3 and 4 to be equipped with selective catalytic reduction (SCR) NOx controls before December 31, 2015 and December 31, 2016, respectively. WDEQ is requiring installation of the two SCR units as part of its long-term strategy in the regional haze SIP. IPC s estimated share of the cost to install the two SCRs is $120 million. Installation of this SCR pollution control equipment could require extended maintenance outages. In addition, WDEQ has proposed to require PacifiCorp to submit an application by January 15, 2015, to install add-on NOx controls at Bridger Units 1 and 2 by December 31, 2023. Design and cost estimates for meeting this proposed requirement are not yet available. The comment period on the draft RH BART SIP ended on August 4, 2009. WDEQ will finalize the SIP and submit it to the EPA for approval. Legal challenges or appeals of the final SIP are possible. IPC will continue to monitor this process.

On August 20, 2008, the ODEQ issued a draft RH BART proposal for the Boardman plant. The RH BART proposal was approved by the Oregon Environmental Quality Commission on June 19, 2009. The pollution control requirements for RH BART and the long-term strategy are estimated to cost between approximately $52 million and $56 million (IPC share) based upon current market conditions for air quality control equipment. Approximately three-quarters of the costs will be incurred by 2014 with the remainder incurred by 2017. Installation of this pollution control equipment could require extended maintenance outages.

New Source Review: 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 New Source Review (NSR) permitting requirements and New Source Performance Standards (NSPS) of the federal Clean Air Act (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. The Obama administration has indicated an intention to continue this NSR enforcement initiative. In 2003, the EPA sent an information request to PacifiCorp, under section 114 of the CAA, requesting information relevant to NSR and NSPS compliance at its power plant operations, including the Jim Bridger plant (of which IPC is a one-third owner). PacifiCorp responded to this and another information request from the EPA for Bridger. Similarly, on June 15, 2009, the EPA sent an information request to NV Energy, Inc. (NV Energy), under section 114 of the CAA, requesting historical operating and capital project information for the Valmy power plant (of which IPC is a one-half owner). NV Energy s first set of responses were sent to EPA on August 24, 2009. In addition, in June 2008, the EPA sent an information request to Portland General Electric Company (PGE), under section 114 of the CAA, requesting information regarding the Boardman coal plant (of which IPC is a one-tenth owner) to determine whether the plant is in compliance with the Oregon State Implementation Plan, federal New Source Performance Standards and other CAA requirements. On March 20, 2009, PGE received from the EPA a follow up request for information relating to the generation, heat input, and emissions of the Boardman plant. PGE has responded to both requests. A number of utilities that have received section 114 information requests have engaged in negotiations with the EPA to address any allegations of non-compliance with NSR and NSPS requirements. In some cases, such negotiations have resulted in settlements requiring the payment of civil penalties, installation of additional pollution controls, the surrender of emission allowances, and the completion of supplemental environmental projects. IPC cannot predict the outcome of these investigatory matters at this time.

Idaho Water Management Issues: For most of this decade, Idaho has experienced below normal precipitation and stream flows which have exacerbated a developing water shortage in Idaho, manifested by a number of water issues including declining Snake River base flows and declining levels in the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer that has been estimated to hold between 200 300 million acre feet (maf) of water. These issues are of interest to IPC because of their potential impacts on generation at IPC s hydroelectric projects.

As a result of declines in river flows, in 2003 several surface water users filed delivery calls with the IDWR, demanding that it manage ground water withdrawals from the ESPA pursuant to the prior appropriation doctrine of first in time is first in right and curtail junior ground water rights that are depleting the aquifer and affecting flows to senior surface water rights. These delivery calls have resulted in several administrative actions before the IDWR to enforce senior water rights as well as judicial actions before the state court challenging the constitutionality of state regulations used by the IDWR to conjunctively administer ground and surface water rights. Because IPC holds water rights that are dependent on the Snake River, spring flows and the overall condition of the ESPA, IPC continues to monitor and participate in these actions, as necessary, to protect its water rights.

One such action relates to the Milner hydroelectric project which is owned by the North Side Canal Company (NSCC) and the Twin Falls Canal Company (TFCC). NSCC and TFCC deliver water to and IPC operates the Milner project. NSCC and TFCC were issued a water permit by IDWR for the hydropower project in the late 1980s, which subordinated the water right to all upstream consumptive uses except hydropower and groundwater recharge. However, on October 20, 2008, the IDWR issued a water right license for the project that subordinated the water right to groundwater recharge. On November 4, 2008, NSCC and TFCC filed a petition for hearing with the IDWR contesting the change in the subordination condition. The IDWR has appointed a hearing officer and granted the motions of several parties to intervene in the case. A hearing date has not been set on the petition. IPC is monitoring, but is unable to predict the outcome of the administrative action.

IPC is also engaged in the Snake River Basin Adjudication (SRBA), a general stream adjudication, commenced in 1987, to define the nature and extent of water rights in the Snake River basin in Idaho, including the water rights of IPC.

On March 25, 2009, IPC and the State of Idaho (State) entered into a settlement agreement with respect to the 1984 Swan Falls Agreement and IPC s water rights under the Swan Falls Agreement, which settlement agreement is subject to certain conditions discussed below. The settlement agreement will also resolve litigation between IPC and the State relating to the Swan Falls Agreement that was filed by IPC on May 10, 2007, with the Idaho District Court for the Fifth Judicial Circuit, which has jurisdiction over SRBA matters including the Swan Falls case.

The settlement agreement resolves the pending litigation by clarifying that IPC s water rights in excess of minimum flows at its hydroelectric facilities between Milner Dam and Swan Falls Dam are subordinate to future upstream beneficial uses, including aquifer recharge. The agreement commits the State and IPC to further discussions on important water management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. It also recognizes that water management measures that enhance aquifer levels, springs and river flows, such as aquifer recharge projects, benefit both agricultural development and hydropower generation and deserve study to determine their economic potential, their impact on the environment and their impact on hydropower generation. These will be a part of the Comprehensive Aquifer Management Plan (CAMP), approved by the Idaho Water Resource Board for the Eastern Snake Plain Aquifer (ESPA), which includes limits on the amount of aquifer recharge. IPC is a member of the ESPA CAMP advisory committee and implementation committee.

On April 24, 2009, the Governor of Idaho signed into law legislation approving provisions contained in the settlement agreement. On May 6, 2009, as part of the settlement, IPC, the Governor of Idaho and the Idaho Water Resource Board executed a memorandum of agreement relating to future aquifer recharge efforts and further assurances as to limitations on the amount of aquifer recharge. IPC and the State have also filed a joint motion to the SRBA court to dismiss the Swan Falls case and enter the stipulated water right decrees set forth in the settlement agreement. At a status conference on the joint motion held on July 21, 2009, parties representing groundwater users in the Eastern Snake Plain Aquifer expressed reservations concerning some of the language proposed by IPC and the State to resolve the litigation. The language that the parties are concerned with relates to the description of the water rights in the decrees to be entered by the SRBA court as contemplated by the Settlement Agreement. Specifically the concerns relate to the language describing the subordination of the rights and its interplay with the original Swan Falls settlement document and implementing legislation. The SRBA court has ordered these matters to be briefed. Opening briefs were filed by the parties on September 4, 2009, and oral argument is scheduled to be held on November 6, 2009.

U.S. Bureau of Reclamation: IPC has filed an action in the U.S. District Court of Federal Claims in Washington, D.C. against the U.S. Bureau of Reclamation relating to a contract right for delivery of water to its hydropower projects on the Snake River to recover damages from the U.S. for the lost generation resulting from the reduced flows and a prospective declaration of contractual rights so as to prevent the U.S. from continued failure to fulfill its contractual and fiduciary duties to IPC. On August 6, 2009, the court extended the discovery schedule to March 3, 2010. IPC is unable to predict the outcome of this action.

OTHER MATTERS:

American Recovery and Reinvestment Act of 2009

The American Recovery and Reinvestment Act of 2009 (ARRA), enacted on February 17, 2009, includes tax and appropriation benefits to the utility industry. IPC submitted a grant application to the DOE on August 6, 2009, requesting matching funds for the $47 million of currently budgeted project funds IPC would invest towards the Smart Grid as well as incremental projects that would be funded if awarded a DOE matching grant. On October 27, 2009, IPC received notice that its application was selected. IPC continues to evaluate additional opportunities under ARRA.

Southwest Intertie Project (SWIP)

On March 28, 2008, Great Basin Transmission, LLC (Great Basin) exercised its option to purchase the southern portion of the SWIP, which consists principally of a federal permit for a specific transmission corridor in Nevada and Idaho and private rights-of-way in Idaho. This sale closed during the second quarter of 2008, and resulted in a net pre-tax gain of approximately $3 million. On December 30, 2008, IPC and Great Basin reached an agreement on the sale of the northern portion of the SWIP, which closed on March 31, 2009 and resulted in a pre-tax gain of $0.2 million.

Critical Accounting Policies and Estimates

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

IDACORP s and IPC s critical accounting policies are reviewed by the Audit Committee of the Board of Directors. These policies are discussed in more detail in the Annual Report on Form 10-K for the year ended December 31, 2008, and have not changed materially from that discussion.

New Accounting Pronouncements

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and IPC 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 September 30, 2009.

Interest Rate Risk

IDACORP and IPC 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 September 30, 2009, IDACORP and IPC had $55 million and $22 million, respectively, in net floating rate debt. Assuming no change in financial structure for either company, if variable interest rates were one percentage point higher than the rates in effect on September 30, 2009, interest rate expense would increase and pre-tax earnings would decrease by approximately $0.5 million for IDACORP and $0.2 million for IPC.

Fixed Rate Debt: As of September 30, 2009, IDACORP and IPC had outstanding fixed rate debt of $1.35 billion and $1.34 billion, respectively. The fair market value of this debt was $1.35 billion for both companies. 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 $125 million for IDACORP and IPC if interest rates were to decline by one percentage point from their September 30, 2009 levels.

Commodity Price Risk

IPC s commodity price risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2008. In a limited manner, IPC utilizes financial energy instruments in addition to physical forward power transactions for the purpose of mitigating price risk related to securing adequate energy to meet utility load requirements in accordance with IPC s Risk Management Policy. This practice falls within the parameters of IPC s Risk Management Policy and these instruments are not used for trading purposes. These financial instruments are used in essentially the same manner as forward transactions to mitigate price risk but are considered derivative instruments and reported at fair value in IDACORP s and IPC s financial statements. Because of the PCA mechanism, IPC records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities. Additional information regarding IPC s use of derivative instruments to manage commodity price risk can be found in Note 12 to IDACORP s and IPC s financial statements.

Credit Risk

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. IPC maintains margin agreements that allow performance assurance collateral to be requested and/or posted with certain counterparties. As of September 30, 2009, IPC did not have a significant balance of assurance collateral posted with any counterparties. Should IPC experience a reduction in its credit rating on IPC s unsecured debt to below investment grade, IPC could be subject to requests by its wholesale counterparties to post performance assurance collateral. Based upon IPC s current energy and fuel portfolio and current market conditions as of September 30, 2009, the approximate amount of additional collateral that could be requested upon a downgrade is approximately $22 million. IPC actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements. Additional information regarding credit risk relating to derivative instruments can be found in Note 12 to IDACORP s and IPC s financial statements.

Equity Price Risk

IDACORP s and IPC s equity price risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2008.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures:

IDACORP:

The Chief Executive Officer and the Chief Financial Officer of IDACORP, based on their evaluation of IDACORP s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of September 30, 2009, have concluded that IDACORP s disclosure controls and procedures are effective.

IPC:

The Chief Executive Officer and the Chief Financial Officer of IPC, based on their evaluation of IPC s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of September 30, 2009, have concluded that IPC s disclosure controls and procedures are effective.

Changes in internal control over financial reporting:

There have been no changes in IDACORP s or IPC s internal control over financial reporting during the quarter ended September 30, 2009, that have materially affected, or are reasonably likely to materially affect, IDACORP s or IPC s internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Please refer to Note 7 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Restrictions on Dividends:

A covenant under IDACORP s credit facility and IPC s credit facility requires IDACORP and IPC 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. These agreements are discussed further in MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS LIQUIDITY AND CAPITAL RESOURCES Financing Programs.

IPC s Revised Code of Conduct approved by the IPUC on April 21, 2008, states that IPC will not pay any dividends to IDACORP that will reduce IPC s common equity capital below 35 percent of its total adjusted capital without IPUC approval.

IPC s ability to pay dividends on its common stock held by IDACORP and IDACORP s ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants or IPC s Code of Conduct. At September 30, 2009, the leverage ratios for IDACORP and IPC were 50 percent and 52 percent, respectively and IPC s common equity capital was 48 percent of its total adjusted capital. Based on these restrictions, IDACORP s and IPC s dividends were limited to $629 million and $531 million, respectively, at September 30, 2009.

IPC s articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. IPC has no preferred stock outstanding.

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

Issuer Purchases of Equity Securities:

IDACORP, Inc. Common Stock

Period	**(a) Total Number of Shares Purchased** [1]	**(b) Average Price Paid per Share**	**(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs**
July 1 July 31, 2009	-	$ -	-	-
August 1 August 31, 2009	1,144	28.34	-	-
September 1 September 30, 2009	-	-	-	-
Total	1,144	$ 28.34	-	-

[1] These shares were withheld for taxes upon vesting of restricted stock

89

ITEM 6. EXHIBITS

*Previously Filed and Incorporated Herein by Reference

*2	Agreement and Plan of Exchange between IDACORP, Inc., and IPC dated as of February 2, 1998. File number 333-48031, Form S-4, filed on 3/16/98, as Exhibit 2.
*3.1	Restated Articles of Incorporation of IPC as filed with the Secretary of State of Idaho on June 30, 1989. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 4(a)(xiii).
*3.2	Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of IPC, as filed with the Secretary of State of Idaho on November 5, 1991. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(ii).
*3.3	Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of IPC, as filed with the Secretary of State of Idaho on June 30, 1993. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(iii).
*3.4	Articles of Amendment to Restated Articles of Incorporation of IPC, as filed with the Secretary of State of Idaho on June 15, 2000. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 3(a)(iii).
*3.5	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on January 21, 2005. File number 1-3198, Form 8-K, filed on 1/26/05, as Exhibit 4.5.
*3.6	Articles of Amendment to Restated Articles of Incorporation of IPC, as amended, as filed with the Secretary of State of Idaho on

	November 19, 2007. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.3.
*3.7	Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998. File number 33-56071-99, Post-Effective Amendment No. 1 to Form S-8, filed on 10/1/98, as Exhibit 3(d).
*3.8	Amended Bylaws of IPC, amended on November 15, 2007, and presently in effect. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.2.
*3.9	Articles of Incorporation of IDACORP, Inc. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.1.
*3.10	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.2.
*3.11	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998. File number 333-00139-99, Post-Effective Amendment No. 1 to Form S-3, filed on 9/22/98, as Exhibit 3(b).
*3.12	Amended Bylaws of IDACORP, Inc., amended on November 15, 2007 and presently in effect. File number 1-14456, Form 8-K, filed on 11/19/07, as Exhibit 3.1.
*4.1	Mortgage and Deed of Trust, dated as of October 1, 1937, between IPC and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees. File number 2-3413, as Exhibit B-2.
*4.2	IPC Supplemental Indentures to Mortgage and Deed of Trust: File number 1-MD, as Exhibit B-2-a, First, July 1, 1939 File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943 File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947 File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948 File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949 File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951 File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957 File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957 File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957 File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958 File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958 File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959 File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960

File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961
File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964
File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966
File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966
File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972
File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974
File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974
File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974
File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976
File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978
File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979
File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981
File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982
File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986
File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989
File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990
File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991
File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991
File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992
File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993
File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993

File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000
File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001
File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003
File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003

	File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iii), Thirty-ninth, October 1, 2003 File number 1-3198, Form 8-K filed on 5/10/05, as Exhibit 4, Fortieth, May 1, 2005 File number 1-3198, Form 8-K filed on 10/10/06, as Exhibit 4, Forty-first, October 1, 2006 File number 1-3198, Form 8-K filed on 6/4/07, as Exhibit 4, Forty-second, May 1, 2007 File number 1-3198, Form 8-K filed on 9/26/07, as Exhibit 4, Forty-third, September 1, 2007 File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008
*4.3	Instruments relating to IPC American Falls bond guarantee (see Exhibit 10.4). File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 4(b).
*4.4	Agreement of IPC to furnish certain debt instruments. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(f).
*4.5	Agreement of IDACORP, Inc. to furnish certain debt instruments. File number 1-14465, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(c)(ii).
*4.6	Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine Corporation, and Idaho Power Migrating Corporation. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 2(a)(iii).
*4.7	Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.1.
*4.8	First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.2.
*4.9	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 333-67748, Form S-3, filed on 8/16/01, as Exhibit 4.13.
*10.1	

	Agreements, dated September 22, 1969, between IPC and Pacific Power & Light Company relating to the operation, construction and ownership of the Jim Bridger Project. File number 2-49584, as Exhibit 5(b).
*10.2	Amendment, dated February 1, 1974, relating to operation agreement filed as Exhibit 10.1. File number 2-51762, as Exhibit 5(c).
*10.3	Agreement, dated as of October 11, 1973, between IPC and Pacific Power & Light Company. File number 2-49584, as Exhibit 5(c).
*10.4	Guaranty Agreement, dated April 11, 2000, between IPC and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 10(c).
*10.5	Guaranty Agreement, dated as of August 30, 1974, between IPC and Pacific Power & Light Company. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(r).
*10.6	Letter Agreement, dated January 23, 1976, between IPC and Portland General Electric Company. File number 2-56513, as Exhibit 5(i).
*10.7	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and IPC. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(s).
*10.8	Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(t).
*10.9	Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(u).
*10.10	Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(v).
*10.11	Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(w).
*10.12	Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10.6. File number 2-68574, Form S-7, filed on 7/23/80,

	as Exhibit 5(x).
*10.13	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(z).
*10.14	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and IPC. File number 2-64910, Form S-7, filed on 6/29/79, as Exhibit 5(y).
*10.15[1]	Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.15.
*10.16[1]	Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.16.
*10.17[1]	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2007, filed on 10/31/07, as Exhibit 10(h)(iii).
*10.18[1]	IDACORP, Inc. Restricted Stock Plan Form of Restricted Stock Agreement (time-vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vi).
*10.19[1]	IDACORP, Inc. Restricted Stock Plan Form of Performance Stock Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vii).
*10.20[1]	Idaho Power Company Security Plan for Board of Directors a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(viii).
*10.21[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.21.

*10.22[1]	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and IPC, as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xix).
*10.23[1]	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xx).
*10.24[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (senior vice president and higher), approved November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.24.
*10.25[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (below senior vice president), approved November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.25.
*10.26[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.26.
*10.27[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan Form of Stock Option Award Agreement (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvi).
*10.28[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan Form of Restricted Stock Award Agreement (time vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvii).
*10.29[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan Form of Restricted Stock Award Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xviii).
*10.30[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan Form of Performance Share Award Agreement (performance with two goals) (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.30.

*10.31[1]	IDACORP, Inc. Executive Incentive Plan, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.31.
*10.32[1]	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.32.
*10.33[1]	IDACORP, Inc. and IPC 2008 and 2009 Compensation for Non-Employee Directors of the Board of Directors, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.33.
*10.34	Framework Agreement, dated October 1, 1984, between the State of Idaho and IPC relating to IPC s Swan Falls and Snake River water rights. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h).
*10.35	Agreement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(i).
*10.36	Contract to Implement, dated October 25, 1984, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(ii).
*10.37	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between IPC and the Twin Falls Canal Company and the Northside Canal Company Limited. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m).
*10.38	Guaranty Agreement, dated February 10, 1992, between IPC and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m)(i).
*10.39	Power Purchase Agreement between IPC and PPL Montana, LLC, dated March 1, 2003 and Revised Confirmation Agreement dated May 9, 2003. File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 10(k).
*10.40	$100 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among IDACORP, Inc., various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, Wells Fargo Bank, N.A. and Bank of America, N.A., as

documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-14465, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(l).

*10.41	$300 Million Five-Year Amended and Restated Credit Agreement, dated as of April 25, 2007, among Idaho Power Company, various lenders, Wachovia Bank, National Association, as administrative agent, swingline lender and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent, and KeyBank National Association, US Bank National Association and Bank of America, N.A., as documentation agents, and Wachovia Capital Markets, LLC and J. P. Morgan Securities Inc., as joint lead arrangers and joint book runners. File number 1-3198, Form 10-Q for the quarter ended March 31, 2007, filed on 5/9/07, as Exhibit 10(m).
*10.42	$170 Million Term Loan Credit Agreement, dated as of February 4, 2009, among Idaho Power Company and JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank, N.A. and Wachovia Bank, National Association, as lenders. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.42.
*10.43	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and IPC. File number 1-3198, Form 8-K, filed on 10/10/06, as Exhibit 10.1.
*10.44	Power Purchase Agreement between IPC and PPL EnergyPlus, LLC, dated June 2, 2008. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2008, filed on 8/7/08, as Exhibit 10.46.
*10.45	Amended and Restated Electric Service Agreement between IPC and Hoku Materials, Inc., dated June 19, 2009. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2009 filed on 8/6/09, as Exhibit 10.45.
*10.46[1]	Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.46.
*10.47[1]	Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.47.
*10.48[1]	Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December

	31, 2008, filed on 2/26/09, as Exhibit 10.48.
*10.49[1]	Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.49.
*10.50[1]	Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.50.
*10.51[1]	Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.51.
*10.52[1]	Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.52.
*10.53[1]	Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.53.
*10.54[1]	Form of IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.54.
*10.55[1]	Form of Letter Agreement to Amend Outstanding IDACORP Financial Services, Inc. Director Deferred Compensation Agreement (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.55.
*10.56[1]	Form of Amendment to IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.56.
*10.57[1]	Form of Termination of IDACORP Financial Services, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.57.
*10.58	

	Settlement Agreement, dated March 25, 2009, between the State of Idaho and IPC relating to the agreement filed as Exhibit 10.34. File number 1-14465, 1-3198, Form 10-Q for the quarter ended March 31, 2009, filed on 5/7/09, as Exhibit 10.58.
*10.59[1]	Exhibit A to the IDACORP, Inc. Executive Incentive Plan, as amended February 24, 2009. File number 1-14465, 1-3198, Form 8-K, filed on 3/2/09, as Exhibit 10.1.
*10.60[1]	Consulting Agreement, dated as of April 1, 2009, by and between Thomas R. Saldin and Idaho Power Company, including its parent IDACORP, Inc. and all subsidiaries and affiliates. File number 1-14465, 1-3198, Form 8-K, filed on 4/3/09, as Exhibit 10.1.
*10.61[1]	Idaho Power Company Employee Savings Plan, as amended and restated as of October 1, 2000 (revised). File number 333-159855, Form S-8, filed on 6/9/09, as Exhibit 4.6.
*10.62[1]	First Amendment to Idaho Power Company Employee Savings Plan, dated May 8, 2002. File number 333-159855, Form S-8, filed on 6/9/09, as Exhibit 4.7.
*10.63[1]	Second Amendment to Idaho Power Company Employee Savings Plan, dated March 31, 2006. File number 333-159855, Form S-8, filed on 6/9/09, as Exhibit 4.8.
10.64[1]	Third Amendment to Idaho Power Company Employee Savings Plan, dated September 15, 2009.
*10.65	Contract for Engineering, Procurement and Construction Services, dated May 7, 2009, between IPC and Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company, for Langley Gulch Power Plant (portions of this exhibit have been redacted and filed separately with the Securities and Exchange Commission in connection with a request for confidential treatment pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended). File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2009, filed on 8/6/09 as Exhibit 10.64.
10.66[1]	Separation Agreement and General Release, dated as of August 31, 2009, by and between James C. Miller and Idaho Power Company, including all of its subsidiaries and affiliates.
10.67[1]	Consulting Agreement, dated as of August 31, 2009, by and between James C. Miller and Idaho Power Company, including its parent IDACORP, Inc. and all subsidiaries and affiliates.
12.1	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)

12.2	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.3	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)
12.4	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IPC)
15	Letter Re: Unaudited Interim Financial Information.
*21	Subsidiaries of IDACORP, Inc. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on 2/28/08, as Exhibit 21.
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification.
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification.
31.3	IPC Rule 13a-14(a) CEO certification.
31.4	IPC Rule 13a-14(a) CFO certification.
32.1	IDACORP, Inc. Section 1350 CEO certification.
32.2	IDACORP, Inc. Section 1350 CFO certification.
32.3	IPC Section 1350 CEO certification.
32.4	IPC Section 1350 CFO certification.
99	Earnings press release for the third quarter 2009.

[1] Management contract or compensatory plan or arrangement.

93

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

IDACORP, Inc.
(Registrant)

Date: October 29, 2009	By:	*/s/J. LaMont Keen* J. LaMont Keen President and Chief Executive Officer
Date: October 29, 2009	By:	*/s/Darrel T. Anderson* Darrel T. Anderson Executive Vice President - Administrative Services and Chief Financial Officer

IDAHO POWER COMPANY
(Registrant)

Date: October 29, 2009	By:	*/s/J. LaMont Keen* J. LaMont Keen

President and Chief Executive Officer

Date: October 29, 2009	By:	*/s/Darrel T. Anderson* Darrel T. Anderson Executive Vice President - Administrative Services and Chief Financial Officer

94

EXHIBIT INDEX

Exhibit Number

10.64[1]	Third Amendment to Idaho Power Company Employee Savings Plan, dated September 15, 2009.
10.66[1]	Separation Agreement and General Release, dated as of August 31, 2009, by and between James C. Miller and Idaho Power Company, including all of its subsidiaries and affiliates.
10.67[1]	Consulting Agreement, dated as of August 31, 2009, by and between James C. Miller and Idaho Power Company, including its parent IDACORP, Inc. and all subsidiaries and affiliates.
12.1	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.2	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IDACORP, Inc.)
12.3	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)
12.4	Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IPC)
15	Letter Re: Unaudited Interim Financial Information.
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification.

31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification.
31.3	IPC Rule 13a-14(a) CEO certification.
31.4	IPC Rule 13a-14(a) CFO certification.
32.1	IDACORP, Inc. Section 1350 CEO certification.
32.2	IDACORP, Inc. Section 1350 CFO certification.
32.3	IPC Section 1350 CEO certification.
32.4	IPC Section 1350 CFO certification.
99	Earnings press release for the third quarter 2009.

[1] Management contract or compensatory plan or arrangement