

IDACORP INC
Form 10-Q
November 06, 2008

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

(Mark One)

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

For the quarterly period ended September 30, 2008
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	82-0130980
	Websites: www.idacorpinc.com www.idahopower.com	

None

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

Edgar Filing: IDACORP INC - Form 10-Q

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 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	Accelerated filer	Non-accelerated filer	Smaller reporting company
Idaho Power Company:	Large accelerated filer	Accelerated filer	Non-accelerated filer	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, 2008:

IDACORP, Inc.:	45,566,370
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

APCU	- Annual Power Cost Update
Cal ISO	- California Independent System Operator
CalPX	- California Power Exchange
CAMP	- Comprehensive Aquifer Management Plan
DSM	- Demand Side Management
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
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
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
NEPA	- National Environmental Policy Act of 1996

Edgar Filing: IDACORP INC - Form 10-Q

O&M	- Operations and Maintenance
OPUC	- Oregon Public Utility Commission
PCA	- Power Cost Adjustment
PCAM	- Power Cost Adjustment Mechanism
PURPA	- Public Utility Regulatory Policies Act of 1978
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

Page

Part I. Financial Information:

Item 1. Financial Statements (unaudited)

IDACORP, Inc.:

Condensed Consolidated Statements of
Income 1-2

Condensed Consolidated Balance Sheets 3-4

Condensed Consolidated Statements of
Cash Flows 5

Condensed Consolidated Statements of
Comprehensive Income 6

Idaho Power Company:

Condensed Consolidated Statements of
Income 7-8

Condensed Consolidated Balance Sheets 9-10

Condensed Consolidated Statements of
Capitalization 11

Condensed Consolidated Statements of
Cash Flows 12

Condensed Consolidated Statements of
Comprehensive Income 13

Notes to Condensed Consolidated Financial Statements 14-32

Reports of Independent Registered Public Accounting Firm 33-34

Item 2. Management's Discussion and Analysis of Financial
Condition and Results of Operations 35-69

Item 3. Quantitative and Qualitative Disclosures About Market Risk 69-70

Item 4. Controls and Procedures 70

Part II. Other Information:

<u>Item 1. Legal Proceedings</u>	70
<u>Item 1A. Risk Factors</u>	70-71
<u>Item 2. Unregistered Sales of Equity Securities and Use of Proceeds</u>	71-72
<u>Item 6. Exhibits</u>	72-78
<u>Signatures</u>	79
<u>Exhibit Index</u>	80

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, project, result, may continue and similar expressions.

Table of Contents

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

IDACORP, Inc.

Condensed Consolidated Statements of Income
(unaudited)

	Three months ended	
	September 30,	
	2008	2007
	(thousands of dollars except for per share amounts)	
Operating Revenues:		
Electric utility:		
General business	\$ 246,639	\$ 211,873
Off-system sales	34,637	34,843
Other revenues	16,831	13,800
Total electric utility revenues	298,107	260,516
Other	1,609	947
Total operating revenues	299,716	261,463
Operating Expenses:		
Electric utility:		
Purchased power	79,513	110,108
Fuel expense	46,467	43,291
Power cost adjustment	(20,105)	(43,749)
Other operations and maintenance	74,778	69,154
Demand-side management	5,956	4,307
Gain on sale of emission allowances	(158)	(1,872)
Depreciation	25,717	25,967
Taxes other than income taxes	4,827	4,714
Total electric utility expenses	216,995	211,920
Other expense	1,144	1,613
Total operating expenses	218,139	213,533
Operating Income (Loss):		
Electric utility	81,112	48,596
Other	465	(666)
Total operating income	81,577	47,930
Other Income	4,629	4,616
Earnings (Losses) of Unconsolidated		
Equity-Method Investments	2,642	(380)
Other Expense	2,764	2,055
Interest Expense:		
Interest on long-term debt	17,226	15,862

Edgar Filing: IDACORP INC - Form 10-Q

Other interest	1,310		763	
Total interest expense	18,536		16,625	
Income Before Income Taxes	67,548		33,486	
Income Tax Expense	15,809		4,555	
Net Income	\$	51,739	\$	28,931
Weighted Average Common Shares Outstanding				
- Basic (000 s)	44,998		44,417	
Weighted Average Common Shares Outstanding				
- Diluted (000 s)	45,194		44,543	
Earnings Per Share of Common Stock:				
Earnings per share-Basic	\$	1.15	\$	0.65
Earnings per share-Diluted	\$	1.14	\$	0.65
Dividends Paid Per Share of Common Stock	\$	0.30	\$	0.30

The accompanying notes are an integral part of these statements.

Table of Contents

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

	Nine months ended	
	September 30,	
	2008	2007
	(thousands of dollars except for per share amounts)	
Operating Revenues:		
Electric utility:		
General business	\$ 602,700	\$ 511,337
Off-system sales	93,640	129,859
Other revenues	43,508	37,776
Total electric utility revenues	739,848	678,972
Other	3,534	2,976
Total operating revenues	743,382	681,948
Operating Expenses:		
Electric utility:		
Purchased power	174,900	241,393
Fuel expense	112,385	101,724
Power cost adjustment	(38,678)	(107,457)
Other operations and maintenance	219,321	215,870
Demand-side management	13,249	8,970
Gain on sale of emission allowances	(504)	(2,754)
Depreciation	78,084	76,870
Taxes other than income taxes	14,431	14,267
Total electric utility expenses	573,188	548,883
Other expense	3,331	4,782
Total operating expenses	576,519	553,665
Operating Income (Loss):		
Electric utility	166,660	130,089
Other	203	(1,806)
Total operating income	166,863	128,283
Other Income	15,128	13,867
Losses of Unconsolidated Equity-Method		
Investments	(4,672)	(3,257)
Other Expense	4,949	6,838
Interest Expense:		
Interest on long-term debt	49,847	43,306
Other interest	3,219	3,881
Total interest expense	53,066	47,187
Income Before Income Taxes	119,304	84,868
Income Tax Expense	28,335	12,891
Income from Continuing Operations	90,969	71,977
	-	67

Income from Discontinued Operations, net of tax

Net Income	\$	90,969	\$	72,044
Weighted Average Common Shares Outstanding - Basic (000 s)		44,923		43,947
Weighted Average Common Shares Outstanding - Diluted (000 s)		45,098		44,080
Earnings Per Share of Common Stock:				
Earnings per share from Continuing Operations-Basic	\$	2.02	\$	1.64
Earnings per share from Discontinued Operations-Basic	-		-	
Earnings Per Share of Common Stock-Basic	\$	2.02	\$	1.64
Earnings per share from Continuing Operations-Diluted	\$	2.02	\$	1.63
Earnings per share from Discontinued Operations-Diluted	-		-	
Earnings Per Share of Common Stock-Diluted	\$	2.02	\$	1.63
Dividends Paid Per Share of Common Stock	\$	0.90	\$	0.90

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

	September 30, 2008	December 31, 2007
Assets	(thousands of dollars)	
Current Assets:		
Cash and cash equivalents	\$ 57,726	\$ 7,966
Receivables:		
Customer	78,192	69,160
Allowance for uncollectible accounts	(1,359)	(7,505)
Employee notes	203	2,128
Other	6,617	10,957
Accrued unbilled revenues	39,065	36,314
Materials and supplies (at average cost)	51,324	43,270
Fuel stock (at average cost)	24,402	17,268
Prepayments	10,299	9,371
Deferred income taxes	14,375	25,672
Refundable income tax deposit	24,903	46,083
Other	8,904	6,023
Total current assets	314,651	266,707
Investments	201,807	201,085
Property, Plant and Equipment:		
Utility plant in service	3,957,199	3,796,339
Accumulated provision for depreciation	(1,499,947)	(1,468,832)
Utility plant in service - net	2,457,252	2,327,507
Construction work in progress	225,965	257,590
Utility plant held for future use	6,318	3,366
Other property, net of accumulated depreciation	27,615	28,089
Property, plant and equipment - net	2,717,150	2,616,552
Other Assets:		
American Falls and Milner water rights	26,592	29,501
Company-owned life insurance	29,535	30,842
Regulatory assets	502,565	449,668
Long-term receivables (net of allowance of \$2,478 and \$1,878, respectively)	4,262	3,583
Employee notes	89	2,325
Other	54,612	53,045
Total other assets	617,655	568,964

Total \$ 3,851,263 \$ 3,653,308

The accompanying notes are an integral part of these statements.

Table of Contents

IDACORP, Inc.
Condensed Consolidated Balance Sheets
(unaudited)

Liabilities and Shareholders Equity	September 30, 2008	December 31, 2007
	(thousands of dollars)	
Current Liabilities:		
Current maturities of long-term debt	\$ 7,817	\$ 11,456
Notes payable	203,915	186,445
Accounts payable	66,195	85,116
Taxes accrued	14,736	8,492
Interest accrued	29,624	18,913
Uncertain tax positions	27,297	26,764
Other	36,883	38,129
Total current liabilities	386,467	375,315
Other Liabilities:		
Deferred income taxes	473,845	466,182
Regulatory liabilities	276,469	274,204
Other	170,794	173,412
Total other liabilities	921,108	913,798
Long-Term Debt	1,273,028	1,156,880
Commitments and Contingencies (Note 6)		
Shareholders Equity:		
Common stock, no par value (shares authorized 120,000,000; 45,575,907 and 45,063,107 shares issued, respectively)	691,162	675,774
Retained earnings	587,998	537,699
Accumulated other comprehensive loss	(8,461)	(6,156)
Treasury stock (9,537 and 380 shares at cost, respectively)	(39)	(2)
Total shareholders equity	1,270,660	1,207,315
Total	\$ 3,851,263	\$ 3,653,308

The accompanying notes are an integral part of these statements.

Table of Contents

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

**Nine Months Ended
September 30,
2008 2007
(thousands of dollars)**

Operating Activities:

Net income	\$ 90,969	\$ 72,044
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	93,192	91,286
Deferred income taxes and investment tax credits	16,075	29,224
Changes in regulatory assets and liabilities	(50,081)	(110,813)
Non-cash pension expense	3,009	7,968
Undistributed earnings of subsidiaries	(3,772)	(4,648)
Gain on sale of assets	(3,369)	(4,437)
Other non-cash adjustments to net income	1,770	(2,289)
Change in:		
Accounts receivable and prepayments	(11,819)	(9,703)
Accounts payable and other accrued liabilities	(16,782)	(19,981)
Taxes accrued	6,244	(15,079)
Other current assets	(17,940)	(9,685)
Other current liabilities	8,971	16,582
Other assets	1,126	758
Other liabilities	(2,188)	5,973
Net cash provided by operating activities	115,405	47,200
Investing Activities:		
Additions to property, plant and equipment	(176,475)	(203,067)
Proceeds from the sale of IDACOMM	-	7,283
Proceeds from the sale of non-utility assets	5,753	-
Investments in affordable housing	(8,486)	300
Proceeds from the sale of emission allowances	2,959	19,846
Investments in unconsolidated affiliates	(3,065)	(4,925)
Purchase of available-for-sale securities	-	(24,349)
Proceeds from the sale of available-for-sale securities	-	26,110
Purchase of held-to-maturity securities	(2,885)	(3,116)
Maturity of held-to-maturity securities	4,610	3,267
Withdrawal of refundable deposit for tax related liabilities	20,000	-
Other	(7,932)	(187)
Net cash used in investing activities	(165,521)	(178,838)
Financing Activities:		
Increase in term loans	170,000	-

Edgar Filing: IDACORP INC - Form 10-Q

Issuance of long-term debt	120,000	140,000
Retirement of long-term debt	(7,630)	(9,978)
Purchase of pollution control bonds	(166,100)	-
Dividends on common stock	(40,516)	(39,629)
Net change in short-term borrowings	13,570	15,813
Issuance of common stock	12,550	34,893
Acquisition of treasury stock	(304)	(346)
Other	(1,694)	(2,355)
Net cash provided by financing activities	99,876	138,398
Net increase in cash and cash equivalents	49,760	6,760
Cash and cash equivalents at beginning of the period	7,966	9,892
Cash and cash equivalents at end of the period	\$ 57,726	\$ 16,652

Supplemental Disclosure of Cash Flow Information:

Cash paid during the period for:		
Income taxes	\$ 8,762	\$ 3,815
Interest (net of amount capitalized)	\$ 40,933	\$ 36,080
Non-cash investing activities		
Additions to property, plant and equipment in accounts payable	\$ 10,527	\$ 6,374

The accompanying notes are an integral part of these statements.

Table of Contents

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

Three Months Ended
September 30,
2008 2007

(thousands of dollars)

Net Income	\$	51,739	\$	28,931
Other Comprehensive Income (Loss):				
Unrealized (losses) gains on securities:				
Unrealized holding (losses) gains arising during the period, net of tax of (\$791) and \$148	(1,232)		231	
Reclassification adjustment for gains included in net income, net of tax of \$0 and (\$31)	-		(48)	
Net unrealized (losses) gains	(1,232)		183	
Unfunded pension liability adjustment, net of tax of \$67 and \$72	104		113	
Total Comprehensive Income	\$	50,611	\$	29,227

The accompanying notes are an integral part of these statements.

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

**Nine Months Ended
September 30,
2008 2007
(thousands of dollars)**

Net Income	\$	90,969	\$	72,044
Other Comprehensive Income (Loss):				
Unrealized (losses) gains on securities:				
Unrealized holding (losses) gains arising during the period, net of tax of (\$1,679) and \$452	(2,616)		704	
Reclassification adjustment for gains included in net income, net of tax of \$0 and (\$592)	-		(922)	
Net unrealized losses	(2,616)		(218)	
Unfunded pension liability adjustment, net of tax of \$200 and \$217	311		338	
Total Comprehensive Income	\$	88,664	\$	72,164

The accompanying notes are an integral part of these statements.

Table of Contents

Idaho Power Company
Condensed Consolidated Statements of Income
(unaudited)

	Three Months Ended	
	September 30,	
	2008	2007
	(thousands of dollars)	
Operating Revenues:		
General business	\$ 246,639	\$ 211,873
Off-system sales	34,637	34,843
Other revenues	16,831	13,800
Total operating revenues	298,107	260,516
Operating Expenses:		
Operation:		
Purchased power	79,513	110,108
Fuel expense	46,467	43,291
Power cost adjustment	(20,105)	(43,749)
Other	58,544	54,625
Demand-side management	5,956	4,307
Gain on sale of emission allowances	(158)	(1,872)
Maintenance	16,234	14,529
Depreciation	25,717	25,967
Taxes other than income taxes	4,827	4,714
Total operating expenses	216,995	211,920
Income from Operations	81,112	48,596
Other Income (Expense):		
Allowance for equity funds used during construction	1,265	1,909
Earnings of unconsolidated equity-method investments	4,487	1,296
Other income	3,428	2,475
Other expense	(2,603)	(2,205)
Total other income	6,577	3,475
Interest Charges:		
Interest on long-term debt	16,916	15,386

Edgar Filing: IDACORP INC - Form 10-Q

Other interest	2,290	2,361
Allowance for borrowed funds used during construction	(1,549)	(2,063)
Total interest charges	17,657	15,684
Income Before Income Taxes	70,032	36,387
Income Tax Expense	22,627	12,279
Net Income	\$ 47,405	\$ 24,108

The accompanying notes are an integral part of these statements.

Table of Contents

Idaho Power Company
Condensed Consolidated Statements of Income
(unaudited)

	Nine months ended	
	September 30,	
	2008	2007
	(thousands of dollars)	
Operating Revenues:		
General business	\$ 602,700	\$ 511,337
Off-system sales	93,640	129,859
Other revenues	43,508	37,776
Total operating revenues	739,848	678,972
Operating Expenses:		
Operation:		
Purchased power	174,900	241,393
Fuel expense	112,385	101,724
Power cost adjustment	(38,678)	(107,457)
Other	168,675	162,073
Demand-side management	13,249	8,970
Gain on sale of emission allowances	(504)	(2,754)
Maintenance	50,646	53,797
Depreciation	78,084	76,870
Taxes other than income taxes	14,431	14,267
Total operating expenses	573,188	548,883
Income from Operations	166,660	130,089
Other Income (Expense):		
Allowance for equity funds used during construction	2,394	4,687
Earnings of unconsolidated equity-method investments	2,621	3,376
Other income	12,502	8,332
Other expense	(5,077)	(6,637)
Total other income	12,440	9,758
Interest Charges:		
Interest on long-term debt	48,868	41,857

Edgar Filing: IDACORP INC - Form 10-Q

Other interest	6,437	7,019
Allowance for borrowed funds used during construction	(4,966)	(5,517)
Total interest charges	50,339	43,359
Income Before Income Taxes	128,761	96,488
Income Tax Expense	42,357	32,885
Net Income	\$ 86,404	\$ 63,603

The accompanying notes are an integral part of these statements.

Table of ContentsIdaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

	September 30, 2008	December 31, 2007
Assets	(thousands of dollars)	
Electric Plant:		
In service (at original cost)	\$ 3,957,199	\$ 3,796,339
Accumulated provision for depreciation	(1,499,947)	(1,468,832)
In service - net	2,457,252	2,327,507
Construction work in progress	225,965	257,590
Held for future use	6,318	3,366
Electric plant - net	2,689,535	2,588,463
Investments and Other Property	106,702	105,074
Current Assets:		
Cash and cash equivalents	36,189	5,347
Receivables:		
Customer	78,192	62,122
Allowance for uncollectible accounts	(1,359)	(1,305)
Employee notes	203	2,128
Other	3,733	8,122
Accrued unbilled revenues	39,065	36,314
Materials and supplies (at average cost)	51,324	43,270
Fuel stock (at average cost)	24,402	17,268
Prepayments	10,028	9,120
Deferred income taxes	3,865	4,074
Refundable income tax deposit	23,927	44,316
Other	6,152	1,067
Total current assets	275,721	231,843
Deferred Debits:		
American Falls and Milner water rights	26,592	29,501
Company-owned life insurance	29,535	30,842
Regulatory assets	502,565	449,668
Employee notes	89	2,325
Other	53,348	51,800

Edgar Filing: IDACORP INC - Form 10-Q

Total deferred debits	612,129	564,136
Total	\$ 3,684,087	\$ 3,489,516

The accompanying notes are an integral part of these statements.

Table of Contents

Idaho Power Company
Condensed Consolidated Balance Sheets
(unaudited)

	September 30, 2008	December 31, 2007
Capitalization and Liabilities	(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	581,758	581,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	488,027	442,300
Accumulated other comprehensive loss	(8,461)	(6,156)
Total common stock equity	1,157,104	1,113,682
Long-term debt	1,260,629	1,141,508
Total capitalization	2,417,733	2,255,190
Current Liabilities:		
Long-term debt due within one year	1,064	1,064
Notes payable	135,263	136,585
Accounts payable	65,614	84,457
Notes and accounts payable to related parties	1,106	724
Taxes accrued	24,039	2,403
Interest accrued	29,447	18,761
Uncertain tax positions	27,297	26,764
Other	35,991	36,907
Total current liabilities	319,821	307,665
Deferred Credits:		
Deferred income taxes	506,617	488,768
Regulatory liabilities	276,469	274,204
Other	163,447	163,689
Total deferred credits	946,533	926,661

Commitments and Contingencies (Note 6)

Total	\$	3,684,087	\$	3,489,516
--------------	----	-----------	----	-----------

The accompanying notes are an integral part of these statements.

Table of Contents

Idaho Power Company
Condensed Consolidated Statements of Capitalization
(unaudited)

	September 30, 2008	%	December 31, 2007	%
	(thousands of dollars)			
Common Stock Equity:				
Common stock	\$ 97,877		\$ 97,877	
Premium on capital stock	581,758		581,758	
Capital stock expense	(2,097)		(2,097)	
Retained earnings	488,027		442,300	
Accumulated other comprehensive loss	(8,461)		(6,156)	
Total common stock equity	1,157,104	48	1,113,682	49
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		-	
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	1,065,000		945,000	
Amount due within one year	-		-	
Net first mortgage bonds	1,065,000		945,000	
Pollution control revenue bonds:				
Variable Rate Series 2003 due 2024	49,800		49,800	
Variable Rate Series 2006 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	

Edgar Filing: IDACORP INC - Form 10-Q

Milner Dam note guarantee	9,573		10,636	
Note guarantee due within one year	(1,064)		(1,064)	
Unamortized premium/discount - net	(3,225)		(3,409)	
Term Loan Credit Facility	166,100		-	
Purchase of pollution control revenue bonds	(166,100)		-	
Total long-term debt	1,260,629	52	1,141,508	51
Total Capitalization	\$ 2,417,733	100	\$ 2,255,190	100

The accompanying notes are an integral part of these statements.

Table of Contents

Idaho Power Company
Condensed Consolidated Statements of Cash Flows
(unaudited)

	Nine Months Ended	
	September 30,	
	2008	2007
	(thousands of dollars)	
Operating Activities:		
Net income	\$ 86,404	\$ 63,603
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	83,285	82,244
Deferred income taxes and investment tax credits	15,173	26,926
Changes in regulatory assets and liabilities	(50,081)	(110,813)
Non-cash pension expense	3,009	7,968
Undistributed earnings of subsidiary	(2,621)	(3,376)
Gain on sale of assets	(3,383)	(4,268)
Other non-cash adjustments to net income	(1,346)	(4,388)
Change in:		
Accounts receivables and prepayments	(12,162)	(13,249)
Accounts payable	(16,175)	(18,565)
Taxes accrued	21,636	2,098
Other current assets	(17,939)	(9,760)
Other current liabilities	8,945	16,580
Other assets	1,121	710
Other liabilities	(1,888)	6,706
Net cash provided by operating activities	113,978	42,416
Investing Activities:		
Additions to utility plant	(176,475)	(202,555)
Proceeds from the sale of non-utility assets	5,690	-
Purchase of available-for-sale securities	-	(24,349)
Proceeds from the sale of available-for-sale securities	-	26,110
Proceeds from sale of emission allowances	2,959	19,846
Investments in unconsolidated affiliate	(3,065)	(4,925)
Withdrawal (refundable deposit) for tax related liabilities	20,000	(43,927)
Other	(7,550)	(186)
Net cash used in investing activities	(158,441)	(229,986)
Financing Activities:		
Increase in term loans	170,000	-

Edgar Filing: IDACORP INC - Form 10-Q

Issuance of long-term debt	120,000	140,000
Retirement of long-term debt	(1,064)	(1,064)
Purchase of pollution control bonds	(166,100)	-
Dividends on common stock	(40,678)	(39,791)
Net change in short term borrowings	(5,222)	92,613
Other	(1,631)	(1,657)
Net cash provided by financing activities	75,305	190,101
Net increase in cash and cash equivalents	30,842	2,531
Cash and cash equivalents at beginning of the period	5,347	2,404
Cash and cash equivalents at end of the period	\$ 36,189	\$ 4,935

Supplemental Disclosure of Cash Flow Information:

Cash paid during the period for:

Income taxes paid to parent	\$ 8,331	\$ 8,978
Interest (net of amount capitalized)	\$ 38,300	\$ 32,270

Non-cash investing activities:

Additions to utility plant in accounts payable	\$ 10,527	\$ 6,374
--	-----------	----------

The accompanying notes are an integral part of these statements.

Table of Contents

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

	Three Months Ended	
	September 30,	
	2008	2007
	(thousands of dollars)	
Net Income	\$ 47,405	\$ 24,108
Other Comprehensive Income (Loss):		
Unrealized (losses) gains on securities:		
Unrealized holding (losses) gains arising during the period, net of tax of (\$791) and \$148	(1,232)	231
Reclassification adjustment for gains included in net income, net of tax of \$0 and (\$31)	-	(48)
Net unrealized (losses) gains	(1,232)	183
Unfunded pension liability adjustment, net of tax of \$67 and \$72	104	113
Total Comprehensive Income	\$ 46,277	\$ 24,404

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,
2008 2007
(thousands of dollars)**

Net Income	\$ 86,404	\$ 63,603
Other Comprehensive Income (Loss):		
Unrealized (losses) gains on securities:		
Unrealized holding (losses) gains arising during the period, net of tax of (\$1,679) and \$452	(2,616)	704
Reclassification adjustment for gains included in net income, net of tax of \$0 and (\$592)	-	(922)
Net unrealized losses	(2,616)	(218)
Unfunded pension liability adjustment, net of tax of \$200 and \$217	311	338
Total Comprehensive Income	\$ 84,099	\$ 63,723

The accompanying notes are an integral part of these statements.

Table of Contents

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.

On February 23, 2007, IDACORP sold all of the outstanding common stock of IDACOMM, Inc. to American Fiber Systems, Inc. The results of operations and the sale of IDACOMM, Inc. are reported as discontinued operations.

Principles of Consolidation

IDACORP's and IPC's condensed consolidated financial statements include the accounts of each company and their consolidated subsidiaries. IDACORP also consolidates two variable interest entities (VIEs) for which it is the primary beneficiary. All significant intercompany balances have been eliminated in consolidation. Investments in entities in which IDACORP and IPC are not the primary beneficiaries, but have the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method.

Through IFS, IDACORP also holds significant variable interests in VIEs for which it is not the primary beneficiary. These VIEs are historic rehabilitation and affordable housing developments in which IFS holds limited partnership interests ranging up to 99 percent. These investments were acquired between 1996 and 2008. IFS' maximum exposure to loss in these developments was \$77 million at September 30, 2008.

Table of Contents**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, 2008, and consolidated results of operations for the three and nine months ended September 30, 2008, and 2007, and consolidated cash flows for the nine months ended September 30, 2008, and 2007. 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, 2007. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year.

Reclassifications

Certain prior year amounts have been reclassified to conform to the current year presentation. The reclassifications that were made to prior year amounts are as follows: Non-cash pension expense was broken out separately from other non-cash adjustments to net income in the operating sections of IDACORP's and IPC's condensed consolidated statements of cash flows; other assets was combined with other in the financing section of IPC's condensed consolidated statements of cash flows; and notes receivable was combined with other receivables in the current assets section of IPC's condensed consolidated balance sheets. Net income and shareholders' equity were not affected by these reclassifications.

Earnings Per Share

The following table presents the computation of IDACORP's basic and diluted earnings per share from continuing operations for the three and nine months ended September 30, 2008 and 2007 (in thousands, except for per share amounts):

	Three months ended September 30, 2008		Nine months ended September 30, 2008	
	2007	2008	2007	2008
Numerator:				
Income from continuing operations	\$ 51,739	\$ 28,931	\$ 90,969	\$ 71,977
Denominator:				
Weighted-average common shares outstanding - basic*	44,998	44,417	44,923	43,947

Effect of dilutive securities:				
Options	32	34	43	41
Restricted Stock	164	92	132	92
Weighted-average common shares outstanding diluted	45,194	44,543	45,098	44,080
Basic earnings per share from continuing operations	\$ 1.15	\$ 0.65	\$ 2.02	\$ 1.64
Diluted earnings per share from continuing operations	\$ 1.14	\$ 0.65	\$ 2.02	\$ 1.63

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

The diluted EPS computation excluded 577,585 and 513,862 options for the three and nine months ended September 30, 2008, because the options' exercise prices were greater than the average market price of the common stock during those periods. For the same periods in 2007, there were 486,800 and 487,200 options excluded from the diluted EPS computation for the same reason. In total, 814,285 options were outstanding at September 30, 2008, with expiration dates between 2010 and 2015.

New Accounting Pronouncements

SFAS 141(R): In December 2007, the FASB issued SFAS 141(R), *Business Combinations (Revised December 2007)*. SFAS 141(R) 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. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. IDACORP and IPC do not expect the adoption of SFAS 141(R) to have a material impact on their consolidated financial statements.

SFAS 160: In December 2007, the FASB issued SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements*. Among other things, SFAS 160 establishes a standard for the way noncontrolling interests (also called minority interests) are presented in consolidated financial statements and standards for accounting for changes in ownership interests. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. An entity may not apply it before that date. IDACORP and IPC do not expect the adoption of SFAS 160 to have a material impact on their consolidated financial statements.

Table of Contents

SFAS 161: In March 2008, the FASB issued SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. SFAS 161 encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. IDACORP and IPC do not expect the adoption of SFAS 161 to have a material impact on their consolidated financial statements.

SFAS 162: In May 2008, the FASB issued SFAS 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States (GAAP) (the GAAP hierarchy). SFAS 162 is effective November 15, 2008. IDACORP and IPC do not expect the adoption of SFAS 162 to have a material impact on their consolidated financial statements.

SFAS 163: In May 2008, the FASB issued SFAS 163, *Accounting for Financial Guarantee Insurance Contracts an interpretation of FASB Statement No. 60*. SFAS 163 is generally effective for financial statements issued for fiscal years beginning after December 15, 2008. IDACORP and IPC do not expect SFAS 163 to impact their consolidated financial statements.

FSP EITF 03-6-1: In June 2008, the FASB issued FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. Under the guidance in FSP EITF 03-6-1, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method described in SFAS No. 128, *Earnings per Share*. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008. All prior-period earnings per share data presented shall be adjusted retrospectively. Early application is not permitted. IDACORP and IPC do not expect EITF 03-6-1 to have a material impact on their consolidated financial statements.

FSP FAS 142-3: In April 2008, the FASB issued FSP FAS 142-3, *Determination of the Useful Life of Intangible Assets*. FSP FAS 142-3 removes the requirement of SFAS 142, *Goodwill and Other Intangible Assets* for an entity to 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. FSP FAS 142-3 replaces the previous useful-life assessment criteria with a requirement 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. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008. IDACORP and IPC do not expect FSP FAS 142-3 to have a material impact on their consolidated 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 rate on continuing operations for the nine months ended September 30, 2008, was 23.8 percent, compared to 15.2 percent for the nine months ended September 30, 2007. IPC's effective tax rate for the nine months ended September 30, 2008, was 32.9 percent, compared to 34.1 percent for the nine months ended September 30, 2007. The differences in estimated annual effective tax rates are primarily due to the amount of pre-tax earnings at IDACORP and IPC, timing and amount of IPC's regulatory flow-through tax adjustments, and lower tax credits from IFS.

Table of Contents

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

During the nine months ended September 30, 2008, IDACORP entered into the following transactions involving its common stock:

85,430 original issue shares were used for awards granted under the 2000 Long-Term Incentive and Compensation Plan.

16,149 original issue shares and 26,359 treasury shares were used for awards granted under the Restricted Stock Plan.

15,100 treasury shares were used for the annual stock grant to directors under the Non-Employee Directors Stock Compensation Plan.

208,221 original issue shares were issued under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings Plan.

203,000 original issue shares were issued in at-the-market offerings at an average price of \$30.53 per share under the Continuous Equity Program. An additional 56,900 shares were issued in October 2008 at an average price of \$30.32 per share.

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, 2008, the maximum number of shares available under the LTICP and RSP were 1,568,551 and 68,027, respectively. The following table shows the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to IPC for those costs associated with IPC's employees (in thousands of dollars):

	IDACORP		IPC	
	Nine months ended		Nine months ended	
	September 30,		September 30,	
	2008	2007	2008	2007
Compensation cost	\$ 3,106	\$ 2,099	\$ 2,933	\$ 1,461
Income tax benefit	\$ 1,214	\$ 821	\$ 1,147	\$ 571

No equity compensation costs have been capitalized.

Stock awards: Restricted stock awards have vesting periods of up to four years. Restricted stock awards entitle the recipients to dividends and voting rights, and unvested shares are restricted 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 the first nine months of 2008 was \$30.54.

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.

Table of Contents

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 2008 was \$22.76.

Stock options: Stock option awards are granted with exercise prices equal to the market value of the stock on the date of grant. The options have a term of 10 years from the grant date and vest over a five-year period. 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.

Rights Agreement

On September 10, 2008, the Rights Agreement between IDACORP and Wells Fargo Bank, N. A., as successor to The Bank of New York, as rights agent, dated as of September 10, 1998, as amended (Rights Agreement), and the preferred share purchase rights (rights) issued thereunder expired in accordance with their terms. As a result, shares of IDACORP common stock are no longer accompanied by a right to purchase, under certain circumstances, one one-hundredth of a share of IDACORP's A Series Preferred Stock. IDACORP common shareholders were not entitled to any payment as a result of the expiration of the Rights Agreement and the rights issued thereunder.

4. FINANCING:

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.

IPC entered into a \$170 million Term Loan Credit Agreement, dated as of April 1, 2008, with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, National Association, as lenders. The Term Loan Credit Agreement provided for the issuance of term loans

(Loans) by the lenders to IPC on April 1, 2008, in an aggregate principal amount of \$170 million. The Loans are due on March 31, 2009. IPC used \$166.1 million of the proceeds from the Loans to effect the mandatory purchase on April 3, 2008, of the Pollution Control Bonds (as discussed below under Pollution Control Revenue Refunding Bonds) and \$3.9 million to pay interest, fees and expenses incurred in connection with the Pollution Control Bonds and the Term Loan Credit Agreement. The Loans may be prepaid, but may not be reborrowed. The Term Loan Credit Agreement is a short-term arrangement; however, \$166.1 million was classified as long-term debt as allowed by SFAS No. 6 *Classification of Short-Term Obligations Expected to Be Refinanced*. IPC has the ability to refinance the Loans on a long-term basis by utilizing its credit facility, provided that the aggregate of the commitments utilizing the credit facility and commercial paper outstanding does not exceed \$300 million. The remaining \$3.9 million of the Loans is classified as short-term debt. At September 30, 2008, 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, 2008, and December 31, 2007 (in thousands of dollars):

	September 30, 2008			December 31, 2007		
	IPC	IDACORP	Total	IPC	IDACORP	Total
Commercial paper outstanding	\$ 131,363	\$ 68,652	\$ 200,015	\$ 136,585	\$ 49,860	\$ 186,445
Other short-term borrowings	3,900	-	3,900	-	-	-
Total	\$ 135,263	\$ 68,652	\$ 203,915	\$ 136,585	\$ 49,860	\$ 186,445
Weighted-avg. interest rate	3.28%	3.04%	3.19%	5.56%	5.45%	5.53%

Table of Contents

On October 7, 2008, IPC utilized the swingline loan feature on its credit facility to draw a \$30 million loan to pay some of its commercial paper at maturity. The swingline loan was repaid on October 21, 2008, with proceeds from the issuance of commercial paper. On October 14, 2008, IDACORP drew a \$35 million floating rate advance on its credit facility to pay some of its commercial paper at maturity.

Long-Term Financing

As of November 5, 2008, IDACORP has \$621 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock.

On April 3, 2008, IPC entered into a Selling Agency Agreement with each of Banc of America Securities LLC, BNY Capital Markets, Inc., J.P. Morgan Securities Inc., KeyBanc Capital Markets Inc., Lazard Capital Markets LLC, Piper Jaffray & Co., RBC Capital Markets Corporation, SunTrust Robinson Humphrey, Inc., Wachovia Capital Markets, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC in connection with the issuance and sale by IPC from time to time of up to \$350 million aggregate principal amount of First Mortgage Bonds, Secured Medium-Term Notes, Series H. On July 10, 2008, IPC issued \$120 million of its 6.025% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due July 15, 2018. IPC used the net proceeds to pay down short-term debt. As of November 5, 2008, IPC has \$230 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds (including medium-term notes) and unsecured debt.

Pollution Control Revenue Refunding Bonds

On April 3, 2008, IPC made a mandatory purchase of the \$49.8 million Humboldt County, Nevada Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2003 and the \$116.3 million Sweetwater County, Wyoming Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2006 (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. The Pollution Control Bonds remain outstanding and have not been retired or cancelled.

5. REGULATORY MATTERS:

Idaho 2007 General Rate Case

On February 28, 2008, the IPUC approved a settlement of IPC's general rate case filed June 8, 2007. The IPUC's order approved an average increase in base rates of 5.2 percent, or approximately \$32.1 million in revenues, effective March 1, 2008. The order also reset the load growth adjustment rate (LGAR) from \$29.41 per MWh to \$62.79 per MWh, but

applied the new rate to only 50 percent of the load growth beginning in March 2008. The LGAR subtracts the cost of serving additional Idaho retail load from the net power supply costs IPC is allowed to include in its power cost adjustment (PCA). In the 2007 general rate case, IPC filed normalized firm base load of 15.6 million MWh as compared with 14.8 million MWh in the 2005 general rate case.

Danskin CT1 Power Plant Rate Case

On March 7, 2008, IPC filed an application with the IPUC requesting recovery of construction costs associated with the gas-fired Danskin CT1 plant located near Mountain Home, Idaho. Danskin CT1 began commercial operations on March 11, 2008. IPC requested adding to rate base approximately \$65 million attributable to the cost of constructing the generating facility and the related transmission and interconnection facilities, which would have resulted in a base rate increase of 1.39 percent, or approximately \$9 million in annual revenues.

On May 30, 2008, the IPUC authorized IPC to add to its rate base \$64.2 million for the Danskin CT1 plant and related facilities, effective June 1, 2008, resulting in a base rate increase of 1.37 percent, or \$8.9 million in annual revenues. Costs not approved in this order will be included in future filings.

Table of Contents

Deferred Net Power Supply Costs

IPC's deferred net power supply costs consisted of the following (in thousands of dollars):

	September 30, 2008	December 31, 2007
Idaho PCA current year		
Deferral for the 2008-2009 rate year*	\$ -	\$ 85,732
Deferral for the 2009-2010 rate year	61,053	-
Idaho PCA true-up awaiting recovery:		
Authorized in May 2007	-	6,591
Authorized in May 2008	70,345	-
Oregon deferral:		
2001 Costs	2,170	2,993
2006 Costs	1,183	2,107
2008 Power cost adjustment mechanism	3,809	-
Total deferral	\$ 138,560	\$ 97,423

*The 2008-2009 PCA deferral balance is reduced by \$16.5 million of emission allowance sales in 2007.

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 and purchased power 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.

The PCA mechanism provides that 90 percent of deviations in power supply costs are to be reflected in IPC's rates for both the forecast and the true-up components.

2008-2009 PCA: On April 15, 2008, IPC filed its 2008-2009 PCA application with the IPUC with a requested effective date of June 1, 2008. The filing requested an increase to existing revenues of approximately \$87.2 million. Subsequently, the IPUC issued an order directing IPC to apply \$16.5 million of gains from the sale of excess SO₂ emission allowances, including interest, against the PCA. This order reduced IPC's request to approximately \$70.7 million.

IPC and the IPUC Staff each proposed deviations from standard IPUC-approved PCA methodology. IPC proposed to flow through to customers 100 percent of the deviation in net power supply costs and PURPA project expenses for the 2008-2009 PCA year instead of a 90/10 sharing between customers and shareholders. This was denied by the IPUC.

The IPUC Staff proposed to use a normal forecast for power supply costs and to change the distribution of base net power supply expenses. The IPUC adopted the IPUC Staff's proposals on May 30, 2008, and approved an increase to 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 adopted distribution methodology spreads base net power supply costs equally across all months as compared to a more seasonal approach that would have allocated significantly more base net power supply costs to the third quarter and less to the first and second quarters. The change in allocation methodology is not expected to have a material impact on annual financial results.

Table of Contents

2007-2008 PCA: On May 31, 2007, the IPUC approved IPC's 2007-2008 PCA filing. The filing increased the PCA component of customers' rates from the then-existing level, which was \$46.8 million below base rates, to a level that is \$30.7 million above those base rates. This \$77.5 million increase was net of \$69.1 million of proceeds from sales of excess SO₂ emission allowances. The new rates became effective June 1, 2007.

Emission Allowances: During 2007, IPC sold 35,000 SO₂ emission allowances for a total of \$19.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately \$18.5 million. On April 14, 2008, the IPUC ordered that \$16.4 million of these proceeds, including interest, be used to help offset the PCA true-up balances from the 2007-2008 PCA. The order also provided that \$0.5 million may be used to fund an energy education program.

In 2005 and early 2006, IPC sold 78,000 SO₂ emission allowances for a total of \$81.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately \$76.8 million. On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit was used to partially offset the PCA true-up balance and was reflected in PCA rates in effect from June 1, 2007, to May 31, 2008.

Oregon: 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 estimated Oregon's jurisdictional share of excess power supply costs to be \$5.7 million. This amount is currently estimated to be \$7.7 million. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. IPC is awaiting an order from the OPUC.

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007. IPC requested authorization to defer an estimated \$3.3 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. A settlement agreement was reached with the OPUC Staff and the Citizens' Utility Board in the amount of \$2 million. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. The settlement stipulation was approved by the OPUC on December 13, 2007.

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. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2000 and 2001, which is discussed further in Note 6 under Western Energy Proceedings at the FERC. Full recovery of the 2001 deferral is not expected until 2009. The 2006-2007 and the 2007-2008 deferrals would have to be amortized sequentially following

the full recovery of the 2001 deferral.

Oregon Power Cost Recovery Mechanism: On August 17, 2007, IPC filed an application with the OPUC requesting the approval of a power cost recovery mechanism similar to the Idaho PCA. A joint stipulation was filed with the OPUC on March 14, 2008, and the OPUC approved the stipulation on April 28, 2008.

The new mechanism allows IPC to recover excess net power supply costs in a more timely fashion than through the previous deferral process. The mechanism differs from the Idaho PCA in that it reestablishes the base net power supply costs annually. In Idaho, the base net power supply costs are set by a general rate case.

Table of Contents

The new regulatory mechanism has two parts: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU has two components: the October Update, where each October IPC will calculate its estimated normalized net power supply expenses for the following April through March test period, and the March Forecast, where each March IPC will file a forecast of its normalized 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 will be adjusted to reflect costs calculated in the APCU.

The PCAM is a true-up to be filed annually in February beginning in 2009. The filing will calculate 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 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, with new combined rates effective each June 1.

On October 6, 2008, the OPUC provided an order clarifying that the PCAM is a deferral under the Oregon statute. IPC expects that deferrals under the PCAM component will be subject to the six percent limitation on annual amortization discussed above. IPC had \$3.8 million deferred under the PCAM at September 30, 2008.

On October 29, 2007, IPC filed the October Update portion of its 2008 APCU with the OPUC reflecting the estimated net power supply expenses for the April 2008 through March 2009 test period. On March 24, 2008, IPC submitted testimony to the OPUC revising its calculation of the October Update to conform to the methodology agreed to by the parties in the stipulation. IPC also submitted the March Forecast, reflecting expected hydroelectric generating conditions and forward prices for the April 2008 through March 2009 test period. The expected power supply costs of \$150 million represented an increase of approximately \$23 million over the October Update.

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 results in a \$4.8 million, or 15.69 percent, increase in Oregon revenues.

On October 23, 2008, IPC filed the October Update portion of its 2009 APCU with the OPUC. The filing reflects that revenues associated with IPC's base net power supply costs would be increased by \$0.8 million over the previous October Update, an average 2.4 percent increase. The October Update will be combined with the March Forecast

portion of the 2009 APCU, with final rates expected to become effective on June 1, 2009.

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

On March 14, 2008, IPC filed an application requesting a \$2.4 million rate reduction under the FCA pilot program for the net over-recovery of fixed costs during 2007. On May 30, 2008, the IPUC approved the rate reduction of \$2.4 million to be distributed to residential and small general service customer classes equally on an energy used basis during the June 1, 2008 through May 31, 2009, FCA year. IPC deferred \$1.7 million of FCA net under-recovery of fixed costs during the nine months ended September 30, 2008.

Table of Contents

Change in Estimate for Depreciation

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.

Open Access Transmission Tariff (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 FERC Form 1 data. The formula rate request included a rate of return on equity of 11.25 percent. Effective June 1, 2006, the FERC accepted rates for IPC amounting to an annual revenue increase of \$11 million based upon 2004 test year data. The rates were accepted 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 the estimated annual revenue increase to approximately \$8.2 million based on 2004 test year data. Approximately \$1.7 million collected in excess of these new rates between June 1, 2006, and July 31, 2007, was refunded with interest to customers in August 2007.

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. IPC has appealed the Initial Decision to the FERC and is awaiting a final FERC order. If implemented, the Initial Decision would reduce the estimated annual revenue increase (based on 2004 test year data) to approximately \$6.8 million and IPC would make additional refunds, including interest, of approximately \$5 million for the June 1, 2006, through September 30, 2008, period. IPC has reserved this entire amount. IPC expects to pursue recovery of amounts not received pursuant to a final order in this proceeding through additional proceedings at the FERC or through the state ratemaking process.

On August 28, 2008, IPC filed an informational filing with the FERC that contains the annual update of the formula rate based on the 2007 test year. The new rate included in the filing is \$18.88 per kW-year, a decrease of \$0.85 per kW-year, or 4.3 percent. The impact of this rate decrease on IPC's revenues will depend on transmission volume sold, which can be highly variable. In 2007, IPC had \$16 million of revenues from sales of transmission to others. New rates were effective October 1, 2008.

Idaho Pension Expense Order

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 and account for pension expense under SFAS 87, *Employers Accounting for Pensions*, 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. The deferral of pension expense did not begin until \$4.1 million of past contributions still recorded on the balance sheet at December 31, 2006, were expensed. For 2007, approximately \$2.8 million was deferred to a regulatory asset beginning in the third quarter. During the nine months ended September 30, 2008, \$5.9 million of pension expense was deferred. IPC did not request a carrying charge on the deferral balance.

6. COMMITMENTS AND CONTINGENCIES:

Guarantees

IPC has agreed to guarantee the performance of one-third of the reclamation activities at Bridger Coal Company, of which IERCO owns a one-third interest. This guarantee, which is renewed each December, was \$60 million at September 30, 2008. Bridger Coal has a reclamation trust fund set aside specifically for the purpose of paying the reclamation costs and expects that the fund will be sufficient to cover all such costs. Because of the existence of the fund, the estimated fair value of this guarantee is minimal.

Table of Contents

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, 2007, and Quarterly Report on Form 10-Q for the quarters ended March 31, 2008, and June 30, 2008, 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 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, which resulted in energy shortages 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, the structure and content of the FERC's market-based rate regime, show cause orders with respect to contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in any one of 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 or estimate the impact they may have on their consolidated financial positions, results of operations or cash flows.

California Refund: 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. That plan included the potential for orders directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund the portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. On July 25, 2001, the FERC issued an order initiating the California Refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water

Resources and the California Attorney General) an Offer of Settlement at the FERC. A number of other parties, representing substantially less than the majority of potential refund claims, chose to opt out of the settlement. After consideration of comments, the FERC approved the Offer of Settlement on May 22, 2006.

Table of Contents

On February 3, 2004, the FERC directed the California Independent System Operator (Cal ISO) to provide status reports with respect to its progress in calculating refunds, fuel and emissions allowance offsets to refunds, and interest. The process of performing the calculations has engaged the Cal ISO for more than four years. On May 16, 2008, the Cal ISO published its Forty-First Status Report and on September 3, 2008, the Cal ISO published its Forty-Second Status Report. The Forty-First and Forty-Second Status Reports are essentially similar. In the Forty-Second Status Report, the Cal ISO stated its intention not to issue another status report until the FERC had provided guidance on a series of unresolved questions, which the Cal ISO considered to be necessary before it completes its calculations. Included among these unresolved questions are three pending alternative dispute resolution matters, several allocation questions and several questions regarding FERC treatment of non-jurisdictional entities exempted from refund obligations, including questions about the relationship of FERC-approved settlements to the allocation to net refund recipients of refund shortfalls otherwise associated with non-jurisdictional entities. The Cal ISO intends to complete work on its calculations after the FERC provides the requested guidance.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the IE and IPC/California Parties settlement. On October 5, 2006, the FERC denied the Port of Seattle's request for rehearing and on October 24, 2006, the Port of Seattle petitioned the Ninth Circuit for review of the FERC orders approving the settlement. On October 25, 2007, the Ninth Circuit lifted the stay as to the Port of Seattle's appeal along with two other cases with which the Port of Seattle's petition remains consolidated and severed the three cases from the remainder of the consolidated cases. Briefs by all participants have now been filed. Oral argument is scheduled for December 16, 2008. IE and IPC intend to vigorously defend their positions in this proceeding, but are unable to predict the outcome of this matter or estimate the impact it may have on their consolidated financial positions, results of operations or cash flows.

Market Manipulation: As part of the California and Pacific Northwest Refund proceedings 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 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior (partnership) in violation of the Cal ISO and CalPX Tariffs. On October 16, 2003, IE and IPC reached agreement with the FERC Staff on two orders commonly referred to as the gaming and partnership show cause orders. The FERC staff submitted a motion to the FERC to dismiss the partnership proceeding, which was approved by the FERC in an order issued on January 23, 2004. The gaming settlement was approved by the FERC on March 4, 2004.

Some parties have sought review of what they claim are the excessively narrow or excessively broad scope of the show cause orders, and the Ninth Circuit has consolidated those claims with the other matters and is holding them in abeyance. The Port of Seattle is the only party to appeal the orders of the FERC approving the gaming settlement. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial positions, results of operations or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing another 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. A FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001, concluding that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. On December 19, 2002, the FERC reopened the proceeding to allow the submission of additional evidence related to alleged manipulation of the power market by market participants. Parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. On June 25, 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit. On August 24, 2007, the Ninth Circuit issued an opinion in the appeal, 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 submitted by the petitioners for the period January 1, 2000, to June 21, 2001, would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources in the proceeding. A number of parties have sought rehearing of the Ninth Circuit's decision. Grays Harbor terminated its participation in the case when Grays Harbor and IPC reached a settlement. IE and IPC intend to vigorously defend their positions in this proceeding, but are unable to predict the outcome of this matter or estimate the impact it may have on their consolidated financial positions, results of operations or cash flows.

Table of Contents

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006, regarding the FERC's decision not to require repricing of certain long-term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. On June 26, 2008, the U.S. Supreme Court issued a decision in one of these cases, *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County* (No. 06-1457) (Snohomish), and 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 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.

This 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. IPC and IE have asserted the Mobile-Sierra doctrine as a defense to the claims asserted in the Pacific Northwest proceeding, involving spot market contracts in an allegedly dysfunctional market. IDACORP, IPC and IE are unable to predict how the FERC will rule on Snohomish on remand or how this decision will 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 filed a Notice of Appeal to the Ninth Circuit. The parties have filed briefs on appeal. Oral argument on the appeal has

not yet been scheduled. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter or estimate the impact it may have on IPC's consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the U.S. District Court for the District of Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal-fired plant (Plant) in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured in the flue gas of a power plant. A formal answer to the complaint was filed by PacifiCorp on April 2, 2007, in which PacifiCorp denied almost all of the allegations and asserted a number of affirmative defenses. IPC is not a party to this proceeding but has a one-third ownership interest in the Plant. PacifiCorp owns a two-thirds interest and is the operator of the Plant. The complaint alleges thousands of opacity permit limit violations by PacifiCorp and seeks a declaration that PacifiCorp has violated opacity limits, a permanent injunction ordering PacifiCorp to comply with such limits, civil penalties of up to \$32,500 per day per violation and the plaintiff's costs of litigation, including reasonable attorney fees.

Table of Contents

Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity compliance status of the Plant. The court has not yet ruled on these motions. On March 13, 2008, the District Court canceled the original trial date of April 21, 2008, but did not schedule a new trial date. On July 7, 2008, the plaintiffs filed a motion requesting the court to schedule a date for oral argument on the pending motions for summary judgment. On July 17, 2008, PacifiCorp filed an opposition to plaintiffs' motion based on the court's order on Initial Pretrial Conference, which stated that dispositive motions will be decided on the briefs without oral argument. The court has yet to rule on plaintiffs' motion. IPC continues to monitor the status of this matter but 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, Sierra Club 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 power 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. The complaint seeks a declaration that PGE has violated opacity limits, a permanent injunction ordering PGE to comply with such limits, injunctive relief requiring PGE to remediate alleged environmental damage and ongoing impacts, civil penalties of up to \$32,500 per day per violation and the plaintiffs' cost of litigation, including reasonable attorney fees. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant. PGE owns 65 percent and is the operator of the plant.

PGE has not answered or otherwise responded to the complaint. IPC intends 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. The initiation of the SRBA resulted from the Swan Falls Agreement, an agreement entered into by IPC and the Governor and Attorney General of Idaho in October 1984 to resolve litigation relating to IPC's water rights at its Swan Falls project. IPC has filed claims to its water rights for hydropower and other uses in the SRBA. Other water users in the basin have also filed claims to water rights. Parties to the SRBA may file objections to water right claims that adversely affect or injure their claimed water rights and the Idaho District Court for the Fifth Judicial District, which has jurisdiction over SRBA matters, then adjudicates the claims and objections and enters a decree defining a party's water rights. IPC has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. One such claim involves a notice of claim of ownership filed on December 22, 2006, by the State of Idaho, for a portion of the water rights held by IPC that are subject to the Swan Falls Agreement.

On May 10, 2007, in order to protect its claims and the availability of water for power purposes at its facilities, and in response to the claim of ownership filed by the State of Idaho, IPC filed a complaint and petition for declaratory and injunctive relief regarding the status and nature of IPC's water rights and the respective rights and responsibilities of the parties under the Swan Falls Agreement. The complaint was filed in the Idaho District Court for the Fifth Judicial District, the court with jurisdiction over the SRBA, against the State of Idaho, the Governor, the Attorney General, the Idaho Department of Water Resources (IDWR) and the Director of the IDWR.

In conjunction with the filing of the complaint and petition, IPC filed motions with the court to stay all pending proceedings involving the water rights of IPC and to consolidate those proceedings into a single action where all issues relating to the Swan Falls Agreement can be determined.

IPC alleged in the complaint, among other things, that contrary to the parties' belief at the time the Swan Falls Agreement was entered into in 1984, the Snake River basin above Swan Falls was over-appropriated and as a consequence there was not in 1984, and there currently is not, water available for new upstream uses over and above the minimum flows established by the Swan Falls Agreement; that because of this mutual mistake of fact relating to the over-appropriation of the basin, the Swan Falls Agreement should be reformed; that the state's December 22, 2006, claim of ownership to IPC's water rights should be denied; and that the Swan Falls Agreement did not subordinate IPC's water rights to aquifer recharge.

Table of Contents

On April 18, 2008, the court issued a Memorandum Decision and Order on Cross-Motions for Summary Judgment upholding the Swan Falls Agreement. Under the Swan Falls Agreement, water rights in excess of the minimum flows established by the agreement are held in trust by the State of Idaho for the use and benefit of IPC and the people of the State of Idaho. Water above these minimum flows is available for subsequent consumptive beneficial uses that are approved in accordance with state law. The court further held that to the extent that the state is not meeting the minimum flows or it is anticipated that the minimum flows will not be met, IPC's water rights that are held in trust are not available for subsequent appropriations and that any appropriations already in place may be subject to curtailment in order to meet the minimum flows. The court found that it was not necessary to address the issue of mutual mistake of fact relating to the over-appropriation of the basin because it found that it was water rights that were the subject of the trust arrangement and not the water itself. The court also stated that issues relating to water availability relate to the administration of water rights and should be addressed, as necessary, in an administrative action before the IDWR.

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The State of Idaho and IPC are now in the process of completing discovery, and have submitted summary judgment motions on the recharge issue. The court has scheduled a hearing for December 4, 2008 for arguments on the summary judgment motions. IPC is unable to predict how the court will rule on the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. Based upon recent developments, however, resolution of that issue is not expected to have a significant effect on the availability of water to IPC's hydropower facilities. IPC is cooperating with the State of Idaho and other water users through an advisory committee in the development of a Comprehensive Aquifer Management Plan (CAMP) to protect and enhance water levels in the Eastern Snake Plain Aquifer (ESPA) and the connected Snake River. Many CAMP committee members had early expectations that groundwater recharge would be a significant component of the plan. However, further study and review has revealed that significant groundwater recharge is not feasible due to the complex hydrology of the ESPA, the lack of infrastructure, and the requirement of compliance with water quality and other environmental standards.

IPC has also filed two actions in federal court against the United States Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River. In 1923, IPC and the United States entered into a contract that facilitated the development of the American Falls Reservoir by the United States on the Snake River in southeast Idaho. This 1923 contract entitles IPC to 45,000 acre-feet of primary storage capacity in the reservoir and 255,000 acre-feet of secondary storage that was to be available to IPC between October 1 of any year and June 10 of the following year as necessary to maintain specified flows at IPC's Twin Falls power plant below Milner Dam. IPC believes that the United States has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, IPC filed an action in the U.S. District Court of Federal Claims in Washington, D.C. on October 15, 2007 to recover damages from the United States for the lost generation resulting from the reduced flows. On September 30, 2008, IPC filed an amended complaint in which IPC seeks, in addition to damages for breach of the 1923 contract, a prospective declaration of contractual rights so as to prevent the United States from continued failure to fulfill its contractual and fiduciary duties to IPC. On October 2, 2008, the court set a discovery schedule requiring that discovery be completed and pre-trial motions filed by October 1, 2009. The court will then set the matter for

trial. IPC is unable to predict the outcome of this action or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

The second action was filed by IPC on October 16, 2007, in the U.S. District Court for the District of Idaho in Boise, Idaho for a declaration of the parties' respective rights and obligations under the 1923 contract and to compel the United States to manage American Falls Reservoir and the Snake River federal reservoir system to ensure that IPC's contract right to secondary storage is fulfilled in the future. Subsequently, IPC and the United States agreed that the issues in this action could be addressed in the action filed in the U.S. District Court of Federal Claims. As a result, the complaint in the Federal Claims Court action was amended and on October 7, 2008, U.S. District Court in Idaho approved a Stipulation of Dismissal filed by IPC and the United States dismissing, without prejudice, the action filed in the District Court of Idaho.

Renfro Dairy: On September 28, 2007, the principals of Renfro Dairy near Wilder, Idaho filed a lawsuit in the District Court of the Third Judicial District of the State of Idaho (Canyon County) against IDACORP and IPC. On March 28, 2008, the plaintiffs filed a First Amended Complaint and Demand for Jury Trial. On July 23, 2008, the plaintiffs were permitted to file a Second Amended Complaint and Demand for Jury Trial. The plaintiffs assert claims for negligence, negligence per se, nuisance, breach of contract, and fraud. The claims are based on allegations that from 1972 until May 25, 2005, IPC discharged stray voltage from its electrical facilities that caused physical harm and injury to the plaintiffs' dairy herd. Plaintiffs seek compensatory damages in excess of \$10,000 to be proven at trial.

Table of Contents

On June 9, 2008, IDACORP and IPC filed a motion to dismiss the complaint, contending that the court lacks jurisdiction over the matter because plaintiffs have failed to exhaust administrative remedies before the IPUC. On October 30, 2008, the District Court issued a Decision on Motion to Dismiss, holding that because the plaintiffs failed to pursue an administrative claim before the IPUC the District Court lacks subject matter jurisdiction over the matter and that the case be dismissed. To date the plaintiffs have neither appealed the District Court's decision nor pursued an administrative claim before the IPUC. Should the plaintiffs pursue the matter, the companies intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

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 was accidental and caused by high winds.

IPC has received claims from a number of the homeowners and their insurers and is continuing its investigation of these claims. 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 and believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

7. 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		Deferred Compensation Plan		Postretirement Benefits	
	2008	2007	2008	2007	2008	2007
Service cost	\$ 3,730	\$ 3,803	\$ 320	\$ 352	\$ 314	\$ 268
Interest cost	6,599	6,114	667	593	946	844
Expected return on plan assets	(8,528)	(8,347)	-	-	(751)	(702)
Amortization of transition obligation	-	-	-	-	510	510
Amortization of prior service cost	162	163	48	43	(134)	(133)
Amortization of net loss	-	-	122	142	-	38
Net periodic benefit cost	1,963	1,733	1,157	1,130	885	825
Costs not recognized due to the effects of regulation	(1,963)	(1,064)	-	-	-	-

Net periodic benefit cost recognized for financial reporting	\$ -	\$ 669	\$ 1,157	\$ 1,130	\$ 885	\$ 825
---	------	--------	----------	----------	--------	--------

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

Table of Contents

	Pension Plan		Deferred Compensation Plan		Postretirement Benefits	
	2008	2007	2008	2007	2008	2007
Service cost	\$ 11,190	\$ 11,409	\$ 959	\$ 1,056	\$ 865	\$ 1,026
Interest cost	19,795	18,343	2,002	1,779	2,623	2,634
Expected return on plan assets	(25,584)	(25,040)	-	-	(2,174)	(2,082)
Amortization of transition obligation	-	-	-	-	1,530	1,530
Amortization of prior service cost	487	488	144	130	(401)	(401)
Amortization of net loss	-	-	366	425	-	302
Net periodic benefit cost	5,888	5,200	3,471	3,390	2,443	3,009
Costs not recognized due to the effects of regulation	(5,888)	(1,064)	-	-	-	-
Net periodic benefit cost recognized for financial reporting	\$ -	\$ 4,136	\$ 3,471	\$ 3,390	\$ 2,443	\$ 3,009

As discussed in Note 5 - Regulatory Matters, the IPUC issued an order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for pension expense as a regulatory asset.

IDACORP and IPC have not contributed and do not expect to contribute to their pension plan in 2008.

8. SEGMENT INFORMATION:

IDACORP's only reportable segment at September 30, 2008, is utility operations, for which the primary source of revenue is the regulated operations of IPC. IFS, which had previously been identified as a reportable segment, is now included in the All Other column. IDACOMM, which had previously been identified as a reportable segment, is now reported as discontinued operations.

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

other tax-advantaged investments, 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, 2008:				
Revenues	\$ 298,107	\$ 1,609	\$ -	\$ 299,716
Income from continuing operations	47,405	4,334	-	51,739
Three months ended September 30, 2007:				
Revenues	\$ 260,516	\$ 947	\$ -	\$ 261,463
Income from continuing operations	24,108	4,823	-	28,931
Total assets at September 30, 2008	\$ 3,684,087	\$ 219,180	\$ (52,004)	\$ 3,851,263
Nine months ended September 30, 2008:				
Revenues	\$ 739,848	\$ 3,534	\$ -	\$ 743,382
Income from continuing operations	86,404	4,565	-	90,969
Nine months ended September 30, 2007:				
Revenues	\$ 678,972	\$ 2,976	\$ -	\$ 681,948
Income from continuing operations	63,603	8,374	-	71,977

9. FAIR VALUE MEASUREMENTS:

IDACORP and IPC partially adopted the provisions of SFAS 157 *Fair Value Measurements* (SFAS 157) on January 1, 2008. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements.

FASB Staff Position FAS 157-2 (FSP FAS 157-2) delayed the implementation of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The delay is intended to allow additional time to consider the effect of implementation issues that have arisen, or that may arise, from the application of SFAS 157. In accordance with FSP FAS 157-2, IPC did not apply the provisions of SFAS 157 to asset retirement obligations.

Table of Contents

In accordance with SFAS 157, IDACORP and IPC have categorized their financial instruments, based on the priority of the inputs to the valuation technique, into a three-level fair value hierarchy. 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. Financial assets and liabilities recorded on the Condensed Consolidated Balance Sheets are categorized 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; or
- 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.

IDACORP's and IPC's Level 2 inputs are based on exchange traded products adjusted for location using corroborated, observable market data.

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, 2008 (in thousands of dollars). IDACORP's and IPC's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
IDACORP				
Assets:				
Derivatives	\$ 228	\$ -	\$ -	\$ 228
Money market funds	5,398	-	-	5,398
Trading securities	6,809	-	-	6,809
Available-for-sale securities	18,529	-	-	18,529
Liabilities:				
Derivatives	\$ -	\$ (404)	\$ -	\$ (404)
IPC				
Assets:				
Derivatives	\$ 228	\$ -	\$ -	\$ 228
Money market funds	5,045	-	-	5,045
Trading securities	5,458	-	-	5,458
Available-for-sale securities	18,529	-	-	18,529
Liabilities:				
Derivatives	\$ -	\$ (404)	\$ -	\$ (404)

Table of Contents

IDACORP and IPC adopted the provisions of SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement 115* (SFAS 159) on January 1, 2008. SFAS 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities*, applies to all entities with available-for-sale and trading securities. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. IDACORP and IPC did not elect the fair value option for any existing eligible items. However, IDACORP and IPC will continue to evaluate new items on a case-by-case basis for consideration of the fair value option.

Table of Contents

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, 2008, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2008 and 2007, and of cash flows for the nine-month periods ended September 30, 2008 and 2007. 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, 2007, and the related consolidated statements of income, comprehensive income, shareholders equity, and cash flows for the year then ended (not presented herein); and in our report dated February 27, 2008, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*, and Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and*

132(R). In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2007 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

DELOITTE & TOUCHE LLP

Boise, Idaho
November 5, 2008

Table of Contents

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, 2008, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2008 and 2007, and of cash flows for the nine-month periods ended September 30, 2008 and 2007. 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, 2007, 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 27, 2008, we expressed an unqualified opinion on those consolidated financial statements, which included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*, and Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* an

amendment of FASB Statements No. 87, 88, 106, and 132(R). In our opinion, the information set forth in the accompanying condensed consolidated balance sheet and statement of capitalization as of December 31, 2007 is fairly stated, in all material respects, in relation to the consolidated balance sheet and statement of capitalization from which it has been derived.

DELOITTE & TOUCHE LLP

Boise, Idaho
November 5, 2008

Table of Contents

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., 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.

On February 23, 2007, IDACORP sold all of the outstanding common stock of IDACOMM, Inc. to American Fiber Systems, Inc. The results of operations of and the sale of IDACOMM, Inc. are reported as discontinued operations.

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, 2007, and the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008, 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:

Table of Contents

Changes in and compliance with governmental policies, including new interpretations of existing policies, and regulatory actions and regulatory audits, including those of the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission, and the Oregon Public Utility Commission with respect to allowed rates of return, industry and rate structure, day-to-day business operations, acquisition and disposal of assets and facilities, operation and construction of plant facilities, provision of transmission services, including critical infrastructure protection and system reliability, relicensing of hydroelectric projects, recovery of power supply costs, recovery of capital investments, present or prospective wholesale and retail competition, including but not limited to retail wheeling and transmission costs, and other refund proceedings;

Changes arising from the Energy Policy Act of 2005;

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

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

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

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;

Impacts from the formation of a regional transmission organization or the development of another transmission group;

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.

Table of Contents

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 2008 Financial Results

A summary of IDACORP's net income and earnings per diluted share is as follows:

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2008	2007	2008	2007
Net income	\$ 51,739	\$ 28,931	\$ 90,969	\$ 72,044
Average outstanding shares - diluted (000s)	45,194	44,543	45,098	44,080
Earnings per diluted share	\$ 1.14	\$ 0.65	\$ 2.02	\$ 1.63

The key factors affecting the change in IDACORP's net income for the third quarter of 2008 include:

IPC's net income, the primary component of IDACORP's net income, was \$47.4 million for the quarter, an increase of \$23.3 million. The key factors causing the change in IPC's net income include:

General business revenue increased \$34.8 million due to a \$17.4 million increase in retail base rates and a \$17.4 million increase in power cost adjustment (PCA) rates.

Improved hydroelectric generating conditions decreased net power supply costs (fuel and purchased power less off-system sales) by \$27.2 million.

The PCA decreased \$23.6 million primarily due to higher amortization expense from prior year excess net power supply costs as well as improved hydroelectric generating conditions.

- o A change in the monthly allocation of base net power supply costs increased the PCA \$17.6 million.

O&M expense increased \$5.6 million due to an increase of \$6.4 million in payroll-related expenses, and \$2.2 million in water lease costs. Partially offsetting these increases was a decrease of \$3.3 million from the fixed cost adjustment mechanism.

Earnings from Bridger Coal increased \$3.2 million due to higher prices and volumes of coal sold.

Interest expense increased \$2.0 million due primarily to increased long-term debt balances.

Income tax expense increased \$10.3 million due principally to higher income before income taxes.

IFS net income decreased \$1.0 million due to lower tax benefits from aging investments.

The key factors affecting the change in IDACORP's net income for the nine months ended September 30, 2008 include:

IPC's net income, the primary component of IDACORP's net income, was \$86.4 million, an increase of \$22.8 million. The key factors causing the change in IPC's net income include:

General business revenue increased \$91.4 million due to an increase of \$21.2 million in retail base rates, an increase of \$65.7 million in PCA rates, and an increase of \$5.8 million due to customer growth.

Improved hydroelectric generating conditions decreased net power supply costs (fuel and purchased power less off-system sales) by \$19.6 million.

The PCA decreased \$68.8 million primarily due to higher amortization expense from prior year excess net power supply costs as well as improved hydroelectric generating conditions.

Interest expense increased \$7.0 million due primarily to increased long-term debt balances.

Table of Contents

Gain on sale of emission allowances decreased \$2.2 million due to fewer sales and lower prices in 2008.

Income tax expense increased \$9.5 million due primarily to higher income before income taxes.

IFS earnings decreased \$3.2 million due to lower tax benefits from aging investments.

2008 General Rate Case

On June 27, 2008, IPC filed an application with the IPUC requesting an average rate increase of approximately 9.9 percent. IPC's proposal would increase its revenues \$67 million annually. The application included a requested return on equity of 11.25 percent and an overall rate of return of 8.55 percent. IPC filed its case based upon a 2008 forecast test year and expects that the new rates will go into effect by February 1, 2009. The IPUC Staff and other intervening parties filed testimony in this case on October 24, 2008. The IPUC Staff recommends an increase of \$9.7 million, or 1.4 percent, a return on equity of 10.25 percent and an overall rate of return of 8.06 percent. IPC is still reviewing the testimony to develop its case for rebuttal. IPC, the IPUC Staff and other parties will file rebuttal testimony on December 3, 2008. IPC is unable to predict the outcome of the case.

2007 General Rate Case

On February 28, 2008, the IPUC approved a settlement of IPC's general rate case filed in 2007, increasing base rates for residential customers 4.7 percent and rates for the other classes of customers 5.65 percent. The rates became effective March 1, 2008, and will increase IPC's annual revenue by \$32.1 million.

Power Cost Adjustment

On May 30, 2008, the IPUC approved a \$73.3 million increase to revenues, effective June 1, 2008, which resulted in an average rate increase to IPC's customers of 10.7 percent. The increase is net of approximately \$16.5 million of gains on sales of excess emission allowances, including interest. In its order, the IPUC adopted the IPUC Staff's proposal to distribute base net power supply costs equally across all months rather than in a method that reflects moderate seasonal variation. While the distribution methodology utilized does not affect the total amount of base net power supply costs used to calculate the PCA deferral, it does affect the quarters in which they are allocated. The impacts of this distribution methodology are discussed in more detail in REGULATORY MATTERS - Deferred Net Power Supply Costs - Idaho - 2008-2009 PCA.

In its order, the IPUC also directed IPC to hold workshops to address PCA-related issues not resolved in the PCA filing. As a result of the workshops, a settlement stipulation was filed with the IPUC on October 14, 2008, that recommends changing the sharing ratio between customers and shareholders, adjusting the Load Growth Adjustment

Rate (LGAR), changing the source of the power supply cost forecast, and including third party transmission expense in the PCA formula. The stipulation is subject to approval by the IPUC. The stipulation is discussed in more detail in REGULATORY MATTERS - Deferred Net Power Supply Costs - Idaho - PCA Workshops.

Water Management Issues

Power generation at the IPC hydroelectric power plants on the Snake River is dependent upon the state water rights held by IPC and the long-term sustainability of the Snake River, tributary spring flows and the Eastern Snake Plain Aquifer that is connected to the Snake River. IPC continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal of preserving, to the fullest extent possible, the long-term availability of water for use at IPC's hydroelectric projects on the Snake River. IPC's involvement includes active participation in the Snake River Basin Adjudication, a judicial action initiated in 1987 to determine the nature and extent of water use in the Snake River basin, judicial and administrative proceedings relating to the conjunctive management of ground and surface water rights, and management and planning processes intended to reverse declining trends in river, spring, and aquifer levels and address the long-term water resource needs of the state. On occasion, resolution of these water management issues involves litigation. IPC is involved in legal actions regarding not only its water rights but also the water rights of others.

For a complete discussion of water management issues see LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Idaho Water Management Issues.

Table of Contents

Liquidity

The credit markets have recently experienced extreme volatility and disruption, which has reduced the amount of credit available to borrowers and increased the cost of capital. IDACORP and IPC have continued to issue commercial paper, but have also utilized their respective credit facilities. On October 7, 2008, IPC used the swingline loan feature of its credit facility to make a \$30 million loan to repay some of its commercial paper at maturity. The swingline loan was repaid on October 21, 2008, with the proceeds of commercial paper. On October 14, 2008, IDACORP made a \$35 million floating rate draw on its credit facility. This draw is not due until the expiration of the credit facility, although IDACORP may prepay this draw at any time. IDACORP and IPC expect that operating cash flow, together with the revolving credit facilities and other external financing, will be adequate to meet their operating and capital needs, although there can be no assurance that continued or increased volatility and disruption in the global capital and credit markets will not impair either company's ability to access these markets on commercially acceptable terms or at all.

2008 Operating and Financial Metrics and 2009 Outlook

The outlook for key operating and financial metrics for 2008 is:

Key Operating & Financial Metrics	2008 Estimates	
	Current	Previous
Idaho Power Operation & Maintenance Expense (Millions)	No change	\$285-\$295
Idaho Power Capital Expenditures (Millions) ⁽¹⁾	\$235-\$250	\$255-\$270
Idaho Power Hydroelectric Generation (Million MWh) (2)	6.7-7.2	6.5-7.5
Non-regulated Subsidiary Earnings (Millions) (3)	No change	\$2.3-\$4.6
Effective Tax Rates:		
Idaho Power	No change	32%-36%
Consolidated IDACORP	No change	22%-26%

(1) The decrease in capital expenditures is largely due to the decline in new customer connections

and the deferral of certain capital expenditures.

(2) The range of estimated hydroelectric generation has been revised to reflect refinements related to river flows.

(3) Estimates include contributions from Ida-West Energy and IDACORP Financial netted against holding company expenses.

As discussed above under Liquidity , the credit and financial markets have recently experienced volatility and disruption. IPC has experienced a slowdown in new customer connections and one of IPC 's largest industrial customers, has announced workforce reductions. As a result, IPC and IDACORP are reviewing their previously announced estimates for capital expenditures, which may result in the cancellation or deferral of projects relating to customer growth and other non-critical projects. Additionally, hiring restrictions have been implemented and are expected to slow the growth of O&M spending in 2009.

Storage levels in major reservoirs upstream of IPC 's Brownlee Reservoir are slightly above average, which is a significant improvement from levels in the fourth quarter of 2007.

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, 2008. In this analysis, the results for 2008 are compared to the same periods in 2007.

Table of Contents

The following table presents the earnings (losses) for IDACORP and its subsidiaries:

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2008	2007	2008	2007
IPC - Utility operations	\$ 47,405	\$ 24,108	\$ 86,404	\$ 63,603
IDACORP Financial Services	710	1,752	2,212	5,374
Ida-West Energy	1,208	993	2,171	2,034
IDACORP Energy	(55)	2	(78)	(75)
Holding company	2,471	2,076	260	1,041
Discontinued operations	-	-	-	67
Total earnings	\$ 51,739	\$ 28,931	\$ 90,969	\$ 72,044
Average common shares outstanding (diluted)	45,194	44,543	45,098	44,080
Diluted earnings per share	\$ 1.14	\$ 0.65	\$ 2.02	\$ 1.63

Utility Operations

Operating environment and hydroelectric conditions: IPC is one of the nation's few investor-owned utilities with a predominantly hydroelectric generating base. Because of its reliance on hydroelectric generation, IPC's generation operations can be significantly affected by weather conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of IPC's hydroelectric facilities, springtime snow pack run-off, 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 net 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 guide 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 the development of the operations 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.

Hydroelectric generation increased 22 percent for the quarter and 14 percent year-to-date as compared to the same periods in 2007. Compared to the 30-year average, hydroelectric generation was three percent higher for the quarter and 13 percent lower for the year-to-date.

Actual observed Brownlee Reservoir inflow for the April through July 2008 period was 4.4 million acre-feet (maf), or 70 percent of average, an improvement from the 2007 April through July inflow of 2.8 maf, or 44 percent of average. Storage in selected reservoirs upstream of Brownlee, as of October 20, 2008, was 106 percent of average. With current stream flow conditions, IPC expects to generate between 6.7 and 7.2 million MWh from its hydroelectric facilities in 2008, compared to 6.2 million MWh in 2007. IPC's modeled median annual hydroelectric generation is 8.5 million MWh, based on hydrologic conditions for the period 1928 through 2006 and adjusted to reflect the current level of water resource development.

Table of Contents

IPC is actively pursuing opportunities to lease water to enhance river flows to produce additional generation at its hydroelectric plants. Idaho is a semi-arid state and the annual availability of water to lease is highly dependent on weather conditions. Water leases are also subject to approval by the IDWR to ensure that other water rights are not impacted. IPC leased 41,620 acre-feet of water from the Idaho Water District #1 rental pool and 45,716 acre-feet of water from the Shoshone Bannock Tribe. Water from both leases flowed during the third quarter.

IPC's system load is dual peaking, with the larger peak demand occurring in the summer. IPC set a new record system peak demand of 3,214 MW on June 30, 2008. The previous system peak of 3,193 MW occurred on July 13, 2007. The all-time winter peak demand is 2,464 MW set on January 24, 2008.

The following table presents IPC's power supply for the three and nine months ended September 30:

	MWh		Total System Purchased		
	Hydroelectric Generation	Thermal Generation	Generation	Power	Total
Three months ended:					
September 30, 2008	1,827	2,183	4,010	1,200	5,210
September 30, 2007	1,499	2,133	3,632	1,693	5,325
Nine months ended:					
September 30, 2008	5,566	5,555	11,121	2,855	13,976
September 30, 2007	4,884	5,341	10,225	4,195	14,420

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

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
Revenue				
Residential	\$ 90,473	\$ 83,066	\$ 259,781	\$ 224,534
Commercial	59,615	50,481	151,624	126,671
Industrial	34,187	28,875	90,124	74,269
Irrigation	62,364	49,451	101,171	85,863
Total	\$ 246,639	\$ 211,873	\$ 602,700	\$ 511,337

Edgar Filing: IDACORP INC - Form 10-Q

MWh				
Residential	1,245	1,301	3,931	3,832
Commercial	1,068	1,077	2,993	2,959
Industrial	846	869	2,523	2,576
Irrigation	1,139	1,042	1,836	1,862
Total	4,298	4,289	11,283	11,229
Customers (average)				
Residential	403,015	398,322	402,035	396,357
Commercial	63,701	61,939	63,317	61,321
Industrial	121	127	121	127
Irrigation	18,533	18,128	18,353	18,014
Total	485,370	478,516	483,826	475,819
Heating degree-days	56	100	3,557	3,009
Cooling degree-days	841	1,001	1,054	1,286
Precipitation (inches)	1.22	0.71	5.36	4.72

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

Table of Contents

General business revenue increased \$34.8 million and \$91.4 million for the quarter and year-to-date, respectively, as compared to the same period in 2007. This increase is primarily attributable to three factors: 1) the effects of rate changes for the current year, 2) changes in customer usage, and 3) customer growth.

Rates: Rate changes positively impacted general business revenue \$34.8 million for the quarter and \$91.4 million year-to-date due to PCA rate increases of \$17.4 million for the quarter and \$65.7 million year-to-date. Increases in retail base rates, including a general rate increase of 5.2 percent effective March 1, 2008 and a 1.37 percent increase for the Danskin plant effective June 1, 2008, also increased revenues \$17.4 million for the quarter and \$21.2 million year-to-date.

Usage: Changes in usage decreased general business revenues \$2.3 million for the quarter and \$1.4 million year-to-date.

Customers: Moderate growth in customer count in IPC's service territory increased revenue \$2.1 million for the quarter and \$5.8 million year-to-date.

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 September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
Revenue	\$ 34,637	\$ 34,843	\$ 93,640	\$ 129,859
MWh sold	498	620	1,520	2,110
Revenue per MWh	\$ 69.55	\$ 56.20	\$ 61.61	\$ 61.54

Off-system sales volumes decreased due to changes made in the Risk Management Policy and forward sales in the third quarter of 2007 that did not occur in 2008.

Other revenues: The following table 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,
--	---	--

Edgar Filing: IDACORP INC - Form 10-Q

	2008	2007	2008	2007
Transmission services and property rental	\$ 11,572	\$ 9,215	\$ 32,634	\$ 29,499
DSM	5,956	4,307	13,249	8,970
Provision for rate refund	(697)	278	(2,375)	(693)
Total	\$ 16,831	\$ 13,800	\$ 43,508	\$ 37,776

An IPUC order allows IPC to record DSM program expenditures as an operating expense with an offsetting amount recorded in other revenues, resulting in no net effect on earnings. IPC recorded \$6.0 million for the quarter and \$13.2 million year-to-date related to DSM activities in other revenues, an increase of \$1.6 million and \$4.3 million for the quarter and year-to-date, respectively, which reflects increased program expenditures.

The provision for rate refund is related to the Open Access Transmission Tariff discussed in REGULATORY MATTERS - Open Access Transmission Tariff (OATT).

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		Nine months ended	
	September 30,		September 30,	
	2008	2007	2008	2007
Purchased power expense	\$ 79,513	\$ 110,108	\$ 174,900	\$ 241,393
MWh purchased	1,200	1,693	2,855	4,195
Cost per MWh purchased	\$ 66.26	\$ 65.04	\$ 61.26	\$ 57.54

Table of Contents

Purchased power expense decreased due to improved hydroelectric generation and the use of leased water which allowed IPC to better utilize its own generation resources and make fewer market purchases to serve load.

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,	
	2008	2007	2008	2007
Fuel expense	\$ 46,467	\$ 43,291	\$ 112,385	\$ 101,724
Thermal MWh generated	2,183	2,133	5,555	5,341
Cost per MWh	\$ 21.29	\$ 20.30	\$ 20.23	\$ 19.05

Higher coal prices and volumes generated at the Jim Bridger and Valmy plants increased fuel expense \$7.0 million for the quarter and \$13.6 million year-to-date. These increases were partially offset by decreases of \$3.6 million for the quarter and \$2.7 million year-to-date due to the reduced use of Bennett Mountain and Danskin plants resulting from cooler weather and increased hydroelectric generation.

PCA: The PCA represents the effects of IPC's power cost regulatory mechanisms in Idaho and Oregon, which are discussed in more detail below in REGULATORY MATTERS - Deferred Net Power Supply Costs. The following table presents the components of PCA expense for the three and nine months ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
Current year power supply cost deferral	\$ (55,469)	\$ (46,987)	\$ (80,638)	\$ (104,953)
Amortization of prior year authorized balances	35,364	3,238	41,960	(2,504)
Total power cost adjustment	\$ (20,105)	\$ (43,749)	\$ (38,678)	\$ (107,457)

The PCA decreased \$23.6 million for the quarter and \$68.8 million year-to-date due to higher amortization expense from prior year excess net power supply costs as well as improved hydroelectric generating conditions. The change

for the quarter was partially offset by a change in the monthly allocation of base net power supply costs, which increased the current year deferral \$17.6 million. This change is discussed in REGULATORY MATTERS - Deferred Net Power Supply Costs - Idaho - 2008-2009 PCA.

Other operations and maintenance expenses: For the quarter, other operations and maintenance expense increased \$5.6 million due to an increase of \$6.4 million in payroll-related expenses and \$2.2 million in water lease costs. Partially offsetting these increases was a decrease of \$3.3 million from the fixed cost adjustment mechanism. For the year-to-date, other operations and maintenance expense increased \$3.5 million. Increases are due to payroll-related expenses of \$9.4 million, water lease costs of \$2.2 million, and purchased services of \$2.7 million. The increases are partially offset by lower outage costs at the thermal plants of \$5.7 million and a decrease of \$4.1 million from the fixed cost adjustment mechanism.

Non-utility Operations

IFS: IFS earnings decreased \$1.0 million for the quarter and \$3.2 million year-to-date as compared to the same periods of 2007. The reduction is primarily due to lower tax benefits and higher investment amortization expense caused by a reduction in the amount of new investments combined with the continued aging of existing investments. IFS 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 \$8.5 million in new investments and generated tax credits of \$8.2 million for the nine months ended September 30, 2008.

Table of Contents

Discontinued operations: On February 23, 2007, IDACORP sold all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc. In the second quarter of 2006, IDACORP management designated the operations of IDACOMM as assets held for sale, as defined by SFAS 144. The operations of this entity are presented as discontinued operations in IDACORP's financial statements. Discontinued operations had no impact on earnings in 2008.

Interest Expense

Interest charges increased \$1.9 million for the quarter and \$5.9 million for the year-to-date. The increases were primarily due to increases in long-term debt balances during 2007 and 2008.

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 rate on continuing operations for the nine months ended September 30, 2008, was 23.8 percent, compared to 15.2 percent for the nine months ended September 30, 2007. IPC's effective tax rate for the nine months ended September 30, 2008, was 32.9 percent, compared to 34.1 percent for the nine months ended September 30, 2007. The differences in estimated annual effective tax rates are primarily due to the amount of pre-tax earnings at IDACORP and IPC, timing and amount of IPC's regulatory flow-through tax adjustments, and lower tax credits from IFS.

LIQUIDITY AND CAPITAL RESOURCES:

Operating Cash Flows

IDACORP's and IPC's operating cash inflows for the nine months ended September 30, 2008 were \$115 million and \$114 million, respectively. Compared to 2007, IDACORP's and IPC's operating cash inflows increased \$68 million and \$72 million, respectively. The increases in IDACORP's and IPC's operating cash inflows primarily result from IPC's PCA mechanism and increased net income. IPC has collected approximately \$44 million more through the PCA in 2008 than in 2007.

Investing Cash Flows

IDACORP's and IPC's investing cash outflows for the nine months ended September 30, 2008, were \$166 million and \$158 million, respectively, compared to \$179 million and \$230 million, respectively, for the nine months ended September 30, 2007. The largest component of investing cash outflows is IPC's utility construction program, which accounted for \$177 million and \$203 million of expenditures for the nine month periods ending September 30, 2008 and 2007, respectively. These cash outflows were partially offset by a \$20 million withdrawal from a \$45 million refundable income tax deposit made in 2006 by IDACORP (which was then funded by IPC in 2007). IPC also had a 2008 cash inflow of \$5.7 million from the sale of SWIP rights-of-way and made a net contribution of \$3 million to its joint venture, Bridger Coal Company. IDACORP made an \$8.5 million investment in affordable housing through its subsidiary, IFS.

Financing Cash Flows

IDACORP's and IPC's financing cash inflows for the nine months ended September 30, 2008 were \$100 million and \$75 million, respectively. These inflows result primarily from the issuance by IPC of \$120 million of its first mortgage bonds, partially offset by dividends paid of \$41 million.

Debt issuances: On April 1, 2008, IPC entered into a \$170 million Term Loan Credit Agreement, of which \$166.1 million was used to purchase pollution control revenue refunding bonds.

On July 10, 2008, IPC issued \$120 million of its 6.025% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due July 15, 2018. IPC used the net proceeds to pay down short-term debt.

Table of Contents

Equity issuances: In September 2008, IDACORP received \$6.2 million from the issuance of 203,000 shares of common stock under its Continuous Equity Program (CEP). The average price of the shares sold was \$30.53. An additional \$2 million was received in October 2008 from the issuance of 56,900 shares under the CEP. The average price of the shares sold was \$30.32. Under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings Plan, IDACORP issued 208,221 shares in 2008 and 250,020 shares in 2007, for proceeds of \$6.4 million and \$8.4 million, respectively.

Discontinued Operations

Cash flows from discontinued operations are included with the cash flows from continuing operations in IDACORP's Consolidated Statements of Cash Flows. The cash flows from discontinued operations have reduced net cash provided by operating activities and increased net cash used in investing activities, except for the cash received in February 2007 from the sale of IDACOMM. The absence of cash flows from these discontinued operations has positively impacted liquidity and capital resources in periods subsequent to the sale.

Financing Programs

Consolidated capitalization ratios were as follows:

	IPC		IDACORP	
	September 30, 2008	December 31, 2007	September 30, 2008	December 31, 2007
Common shareholders equity	45.3%	46.5%	46.1%	47.1%
Long-term debt*	49.4%	47.8%	46.5%	45.6%
Short-term debt	5.3%	5.7%	7.4%	7.3%

*Includes the current portion of long-term debt

Shelf registrations: IDACORP currently has \$621 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock. As of November 5, 2008, IDACORP has 822,245 shares of common stock available to be issued pursuant to its Sales Agency Agreement with BNY Capital Markets, Inc., dated December 15, 2005, as amended. The Sales Agency Agreement expires November 30, 2008.

On April 3, 2008, IPC entered into a Selling Agency Agreement with each of Banc of America Securities LLC, BNY Capital Markets, Inc., J.P. Morgan Securities Inc., KeyBanc Capital Markets Inc., Lazard Capital Markets LLC, Piper Jaffray & Co., RBC Capital Markets Corporation, SunTrust Robinson Humphrey, Inc., Wachovia Capital Markets, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC in connection with the issuance and sale by

IPC from time to time of up to \$350 million aggregate principal amount of First Mortgage Bonds, Secured Medium-Term Notes, Series H. As of November 5, 2008, IPC has \$230 million remaining on the shelf registration statement.

Credit facilities: IDACORP's credit facility is a \$100 million five-year credit agreement that terminates on April 25, 2012. This credit facility, which is used for general corporate purposes and commercial paper backup, 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 credit facility to \$150 million and to request one-year extensions of the then existing termination date. At September 30, 2008, no loans were outstanding on IDACORP's facility and \$69 million of commercial paper was outstanding. At November 5, 2008, \$35 million in loans and \$23 million of commercial paper was outstanding.

IPC's credit facility is a \$300 million five-year credit agreement that terminates on April 25, 2012. This credit facility, which is used for general corporate purposes and commercial paper backup, 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 credit facility to \$450 million and to request one-year extensions of the then existing termination date. At September 30, 2008, no loans were outstanding on IPC's facility and \$131 million of commercial paper was outstanding. At November 5, 2008, no loans and \$146 million of commercial paper were outstanding.

Table of Contents

IDACORP's and IPC's credit facilities both contain covenants requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization of no more than 65 percent as of the end of each fiscal quarter. At September 30, 2008, the leverage ratios for IDACORP and IPC were 54 percent and 55 percent, respectively. Based on these covenants, IDACORP and IPC had \$471 million and \$405 million, respectively, available to dividend at September 30, 2008. At September 30, 2008, IDACORP and IPC were each in compliance with all other covenants in their respective credit facilities.

Term Loan Credit Agreement: IPC entered into a \$170 million Term Loan Credit Agreement, dated as of April 1, 2008, with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A., and Wachovia Bank, National Association, as lenders. The Term Loan Credit Agreement provided for the issuance of term loans (Loans) by the lenders to IPC on April 1, 2008, in an aggregate principal amount of \$170 million. The Loans are due on March 31, 2009 and may be prepaid but may not be reborrowed. IPC used the proceeds to effect a mandatory purchase on April 3, 2008, of the pollution control bonds (as discussed below in "Pollution Control Revenue Refunding Bonds"), and to pay interest, fees and expenses incurred in connection with the Pollution Control Bonds and the Term Loan Credit Agreement.

IPC has regulatory authority to incur up to \$450 million of short-term indebtedness.

Pollution Control Revenue Refunding Bonds: On April 3, 2008, IPC made a mandatory purchase of the \$49.8 million Humboldt County, Nevada Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2003 and the \$116.3 million Sweetwater County, Wyoming Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2006 (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. IPC is the current holder of the bonds, but ultimately expects to remarket the bonds to investors.

Contractual Obligations

There have been no material changes in contractual obligations outside of the ordinary course of business since December 31, 2007 with the exception of the following:

- On April 1, 2008, IPC entered into a Term Loan Credit Agreement in the amount of \$170 million. The Loans are due March 31, 2009. Additional details relating to the Loans are discussed above under "Financing Programs - Term Loan Credit Agreement."

- On July 10, 2008, IPC issued \$120 million of its 6.025% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due July 15, 2018.
- On June 2, 2008, IPC entered into a purchased power contract with PPL EnergyPlus, LLC that is expected to total \$19.1 million during 2010-2011.
- IPC has entered into contracts with four companies in connection with the deployment of Advanced Metering Infrastructure (AMI). IPC estimates it will spend up to \$71 million from 2009 through 2011 for AMI. The AMI contracts are further discussed in REGULATORY MATTERS - Advanced Metering Infrastructure.
- On October 14, 2008, IDACORP made a \$35 million floating rate draw on its credit facility. The draw is due on April 25, 2012 when the credit facility expires.
- IPC entered into an agreement with Northwest Pipeline GP for transportation of gas supplies. The contract is expected to total \$46 million during 2012-2027.

In accordance with the Pension Protection Act of 2006, companies are required to be 94 percent funded for their outstanding qualified pension obligations as of January 1, 2009, in order to avoid a scheduled series of required annual contributions to reach 100 percent funding over seven years. As of December 31, 2007, qualified pension liabilities were nearly fully funded; however, recent market volatility and the decline in the value of pension assets in 2008 make it likely that IPC will need to make contributions to maintain the minimum required funding target. Partially offsetting this decline in the value of pension assets for 2008 is an expected increase in discount rates that will reduce measured liabilities and thus help mitigate the underfunded amount. Discount rates affect the amount of liability that will be effectively settled and for IDACORP and IPC are determined based on a hypothetical portfolio of high quality bonds. Because asset values and discount rates that will apply are not measured or determined until December 31, 2008, the amount of contributions that would be required to reach minimum targeted levels is not yet determinable. Based on the value of pension assets and interest rates as of September 30, 2008, the estimated contributions required to reach 100 percent funding over seven years would be approximately \$40 million in 2010 and \$20 million in each of 2011, 2012, and 2013. These amounts could change significantly depending upon the plan's funding status at December 31, 2008, and thereafter.

Table of Contents

Credit Ratings

S&P: On November 5, 2008, Standard & Poor's Ratings Services (S&P) announced that it had raised the senior unsecured debt ratings of IPC from BBB- to BBB after reevaluating its application of notching criteria to better reflect the recovery prospects of creditors in the investor-owned utility sector. IPC's senior unsecured debt is now rated the same as the corporate credit rating. This new approach did not affect the senior unsecured debt rating of IDACORP, which remains at BBB-.

Moody's: On June 3, 2008, Moody's Investors Service (Moody's) announced that it had revised its rating outlook to negative from stable for IDACORP and IPC, while affirming the existing ratings for both companies. Moody's affirmed its Baa2 Issuer Rating on IDACORP and Baa1 senior unsecured rating on IPC, and its P-2 commercial paper rating on both companies.

Moody's stated that the outlook revision primarily reflects its concern about weakness in IPC's credit metrics in recent periods, reflecting the effects of poor hydro conditions and the adverse impact of the load growth adjustment rate on IPC's earnings and cash flow. Moody's also stated that IPC faces a higher than historical average capital program over the next several years, which will require significant external financing to fund the expected negative free cash flow.

Fitch: On March 24, 2008, Fitch Ratings, Inc. (Fitch) announced that it revised its rating outlook to negative from stable for IDACORP and IPC, while affirming the existing ratings for both companies. Fitch affirmed its BBB Issuer Default Rating (IDR) on IDACORP and IPC, its F2 short-term IDR rating on IDACORP and IPC, its A- rating on IPC's senior secured debt, its BBB+ rating on IPC's senior unsecured debt and its F2 ratings on IDACORP's and IPC's commercial paper.

Fitch stated that the outlook revision primarily reflects weakening underlying credit metrics due to IPC's inability under its power cost adjustment mechanism to fully recover higher thermal generation production and purchased power costs in rates. Fitch also cited below normal water conditions in six of the last seven years and the appearance that 2008 could extend that trend. Fitch stated that this dynamic in concert with a relatively large capital investment program and timing differences between when those costs are incurred and reflected in rates appear likely to result in earnings, cash flow and credit metrics more consistent with low BBB creditworthiness.

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 of IDACORP's and IPC's securities:

S&P	Moody's	Fitch
----------------	----------------	--------------

Edgar Filing: IDACORP INC - Form 10-Q

	IPC	IDACORP	IPC	IDACORP	IPC	IDACORP
Corporate Credit Rating	BBB	BBB	Baa 1	Baa 2	None	None
Senior Secured Debt	A-	None	A3	None	A-	None
Senior Unsecured Debt	BBB (prelim)	BBB- (prelim)	Baa 1	Baa 2	BBB+	BBB
Short-Term Tax-Exempt Debt	BBB-/A-2	None	Baa 1/ VMIG-2	None	None	None
Commercial Paper	A-2	A-2	P-2	P-2	F2	F2
Credit Facility	None	None	Baa 1	Baa 2	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.

Table of Contents

Capital Requirements

IDACORP's internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2008 through 2010, where capital requirements are defined as utility construction expenditures, excluding Allowance for Funds Used During Construction, plus other regulated and non-regulated investments. This excludes mandatory or optional principal payments on debt obligations. As discussed in IDACORP's Annual Report on Form 10-K for the year ended December 31, 2007, IDACORP may fund capital requirements with a combination of internally generated funds, the use of revolving credit facilities and the issuance of long-term debt and equity.

The credit and financial markets have recently experienced volatility and disruption. IPC has experienced a slowdown in new customer connections and one of IPC's largest industrial customers has announced workforce reductions. As a result, IPC and IDACORP are reviewing their previously announced estimates for capital expenditures, which may result in the cancellation or deferral of projects related to customer growth and other non-critical projects.

REGULATORY MATTERS:

Idaho Rate Cases

2008 General Rate Case: On June 27, 2008, IPC filed an application with the IPUC requesting an average rate increase of approximately 9.9 percent. IPC's proposal would increase its revenues \$67 million annually. The application included a requested return on equity of 11.25 percent and an overall rate of return of 8.55 percent. IPC filed its case based upon a 2008 forecast test year. IPC has responded to data requests from IPUC Staff and intervenors. The IPUC Staff and other intervening parties filed testimony in this case on October 24, 2008. The IPUC Staff recommends an increase of \$9.7 million, or 1.4 percent, a return on equity of 10.25 percent and an overall rate of return on 8.06 percent. IPC is still reviewing the testimony to develop its case for rebuttal. IPC, the IPUC Staff and other parties will file rebuttal testimony on December 3, 2008. Technical hearings are scheduled to begin on December 16, 2008. IPC expects that the new rates will go into effect by February 1, 2009, but is unable to predict the outcome of the case.

2007 General Rate Case: On June 8, 2007, IPC filed an application with the IPUC requesting an average rate increase of 10.35 percent (\$63.9 million annually). On February 28, 2008, the IPUC approved a settlement stipulation that included an average increase in base rates of 5.2 percent (approximately \$32.1 million annually), effective March 1, 2008. The settlement did not specify an overall rate of return or a return on equity. The currently authorized rate of return remains at 8.1 percent.

The parties to the proceeding also agreed in the settlement to make a good faith effort to develop a mechanism to adjust or replace the current LGAR of \$29.41 per MWh. As an interim solution, the parties agreed to use the LGAR

of \$62.79 per MWh recommended by the IPUC Staff on December 10, 2007, but to apply it to only 50 percent of the load growth beginning in March 2008.

The parties also agreed to participate in a good faith discussion regarding a forecast test year methodology that balances the auditing concerns of the IPUC Staff and intervenors with IPC's need for timely rate relief.

On March 12, 2008, IPC, the IPUC Staff, and other parties to this general rate case conducted a workshop to discuss the appropriate approach to the development of a forecast test year. IPC described a method that would start with historical, regulatory-adjusted financial information that could be audited by the IPUC Staff and others. That information would be escalated under commonly accepted methods into the forecast test year for revenues, expenses and rate base. IPC would support the historical information, the adjustments, and the escalation methods as part of its general rate case filing. The parties to the workshop expressed general agreement to this approach and also agreed that no further workshops would be necessary. IPC developed the 2008 test year using this method in its 2008 general rate case filing made on June 27, 2008.

Danskin CT1 Power Plant Rate Case: On March 7, 2008, IPC filed an application with the IPUC requesting recovery of construction costs associated with the gas-fired Danskin CT1 plant located near Mountain Home, Idaho. Danskin CT1 began commercial operations on March 11, 2008. IPC requested adding to rate base approximately \$65 million attributable to the cost of constructing the generating facility and the related transmission and interconnection facilities, which would have resulted in a base rate increase of 1.39 percent, or approximately \$9 million in annual revenues.

On May 30, 2008, the IPUC authorized IPC to add to its rate base \$64.2 million for the Danskin CT1 plant and related facilities, effective June 1, 2008, resulting in a base rate increase of 1.37 percent, or \$8.9 million in annual revenues. Costs not approved in this order will be included in future filings.

Table of Contents**Deferred Net Power Supply Costs**

The following table presents the balances of deferred net power supply costs:

	September 30, 2008	December 31, 2007
Idaho PCA current year:		
Deferral for the 2008-2009 rate year \$	-	\$ 85,732
*		
Deferral for the 2009-2010 rate year	61,053	-
Idaho PCA true-up awaiting recovery:		
Authorized in May 2007	-	6,591
Authorized in May 2008	70,345	-
Oregon deferral:		
2001 Costs	2,170	2,993
2006 Costs	1,183	2,107
2008 Power cost adjustment mechanism	3,809	-
Total deferral	\$ 138,560	\$ 97,423

*The 2008-2009 PCA deferral balance is reduced by \$16.5 million of emission allowance sales in 2007.

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 and purchased power 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.

The PCA mechanism provides that 90 percent of deviations in power supply costs are to be reflected in IPC's rates for both the forecast and the true-up components.

2008-2009 PCA: On April 15, 2008, IPC filed its 2008-2009 PCA application with the IPUC with a requested effective date of June 1, 2008. The filing requested an increase to existing revenues of approximately \$87.2 million. Subsequently, the IPUC issued an order directing IPC to apply \$16.5 million of gains from the sale of excess SO₂ emission allowances, including interest, against the PCA. This order reduced IPC's request to approximately \$70.7 million.

IPC and the IPUC Staff each proposed deviations from standard IPUC-approved PCA methodology. IPC proposed to flow through to customers 100 percent of the deviation in net power supply costs and PURPA project expenses for the 2008-2009 PCA year instead of a 90/10 sharing between customers and shareholders. This was denied by the IPUC.

The IPUC Staff proposed to use a normal forecast for power supply costs and to change the distribution of base net power supply expenses. The IPUC adopted the IPUC Staff's proposals on May 30, 2008 and approved an increase to 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.

Table of Contents

The adopted distribution methodology spreads base net power supply costs equally across all months as compared to a more seasonal approach that would have allocated significantly more base net power supply costs to the third quarter and less to the first and second quarters. This change in allocation methodology is not expected to have a material impact on annual financial results. As a result of the 2007 general rate case, \$127.5 million of net power supply costs have been included in base rates beginning March 1, 2008. After adjusting for the Idaho jurisdictional split and recognizing the 90/10 sharing between customers and shareholders, base net power supply costs used in the PCA deferral calculation are approximately \$117.5 million.

The following table compares the quarterly estimated pre-tax impact of the two methodologies:

	Base Net Power Supply Costs					
	March 1, 2008 through February 28, 2009					
	(\$ amounts in millions)					
	2008	2008	2008	2008	2009	
	First	Second	Third	Fourth	First	
	Quarter	Quarter	Quarter	Quarter	Quarter	Total
PCA Base (seasonal distribution)	\$ 3.3	\$ 26.6	\$ 46.4	\$ 29.6	\$ 11.6	\$ 117.5
PCA Base (even distribution)	9.7	29.4	29.4	29.4	19.6	117.5
PCA Expense increase/(decrease)	\$ 6.4(1)	\$ 2.8	\$ (17.0)	\$ (0.2)	\$ 8.0	\$ 0.0

(1) Due to the IPUC's approval of the even monthly distribution of base net power supply costs on May 30, 2008 with an effective date of

March 1, 2008, IPC recognized an additional \$6.4 million of PCA expense related to the March 2008 time period in the second quarter 2008.

As a result of this change, the quarterly results have experienced significant shifts from one quarter to another as compared to historical results; however, the total impact from any distribution methodology should be zero within a twelve month period. The stipulation that IPC entered into on October 14, 2008, and discussed below, provides for a further change in the base net power supply cost distribution methodology.

PCA Workshops: In its May 30, 2008 order approving IPC's 2008-2009 PCA, the IPUC also directed IPC to set up workshops to address PCA-related issues not resolved in the PCA filing. Workshops were held on July 30, August 13 and September 3, 2008, with the IPUC Staff and several of IPC's largest customers (together, the Parties). Consensus

was reached on all items except allocation of the PCA among customer classes, which will be re-examined following the conclusion of the 2008 general rate case. A settlement stipulation was filed with the IPUC on October 14, 2008. The stipulation, if approved, would:

- Change the sharing ratio allocating the costs and benefits of net power supply costs from the current 90 percent customers and 10 percent shareholders to 95 percent customers and five percent shareholders. IPC would continue to recover 100 percent of the costs of energy purchased from PURPA qualifying facilities. When the 90/10 sharing methodology was first adopted, the 10 percent component represented approximately 50 basis points of IPC's earnings. It now represents more than 100 basis points. Changing the sharing methodology to 95/5 could restore IPC's risk to approximately 50 basis points of earnings. The historic rationale for the 90/10 sharing methodology was to assure that IPC and customer interests were aligned and that IPC made prudent decisions regarding its power supply costs. Since the adoption of the sharing methodology, there has been a substantial increase in the magnitude and volatility of power supply costs and IPC has developed a risk management policy which makes the process for energy purchases and sales far more prescriptive. This change in sharing methodology would become effective on the first day of the month following IPUC approval of the stipulation.

Table of Contents

- Adjust the Load Growth Adjustment Rate (LGAR). The LGAR is a rate used to estimate the fluctuation in revenues and power supply expenses associated with load growth resulting from changes in weather conditions, customer base, or customer use patterns. This estimate adjusts upward or downward the variance between actual net power supply costs and power supply costs in base rates. The IPUC-approved settlement of 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. In the stipulation, the Parties agreed on a formula that, based on filed data from the 2008 general rate case, would produce an LGAR of \$28.14 per MWh. The LGAR formula contained in the stipulation is expected to reduce the negative impact of the LGAR on IPC's future ability to recover its power supply costs. This new methodology would become effective when new rates are implemented as a result of the 2008 general rate case. In the 2008 general rate case, IPC filed normalized firm base load of 15.9 million MWh as compared with 15.6 million MWh in the 2007 general rate case.
- Change the source of the power supply cost forecast. The Parties agreed to use IPC's operation plan forecast of net power supply costs developed as a part of its risk management process as the starting point for the PCA calculation. This forecast would replace a regression formula that is based on projected April-July Brownlee Reservoir inflows provided by the National Weather Service's Northwest River Forecast Center (regression formula). The Parties agreed that the regression formula is no longer the best tool to forecast IPC's net power supply costs. 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. This new methodology would become effective commencing with IPC's next PCA filing in April 2009.
- Include third-party transmission expense. The Parties agreed that 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 and that deviation in these types of costs from levels included in base rates should be reflected in PCA computations. The current PCA formula does not include transmission charges. The parties agreed that these costs, including losses, would be included when the base is established as a result of the 2008 general rate case.
- Adjust the distribution of base net power supply costs. The Parties agreed that the base net power supply costs should be distributed based upon the monthly shape of normalized revenues. The methodology for distribution of these costs was changed in the 2008-2009 PCA, as discussed above, effective March 1, 2008. The stipulation would result in a further change in the methodology, which would become effective when base rates are changed as a result of the 2008 general rate case.

2007-2008 PCA: On May 31, 2007, the IPUC approved IPC's 2007-2008 PCA filing. The filing increased the PCA component of customers' rates from the then-existing level, which was \$46.8 million below base rates, to a level that is \$30.7 million above those base rates. This \$77.5 million increase was net of \$69.1 million of proceeds from sales of excess SO₂ emission allowances. The new rates became effective June 1, 2007.

Emission Allowances: During 2007, IPC sold 35,000 SO₂ emission allowances for a total of \$19.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately \$18.5 million. On April 14, 2008, the IPUC ordered that \$16.4 million of these proceeds, including interest, be used to help offset the PCA true-up balances from the 2007-2008 PCA. The order also provided that \$0.5 million may be used to fund an energy education program.

In 2005 and early 2006, IPC sold 78,000 SO₂ emission allowances for a total of \$81.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately \$76.8 million. On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit was used to partially offset the PCA true-up balance and was reflected in PCA rates in effect from June 1, 2007, to May 31, 2008.

The bulk of IPC's accumulated excess emission allowances were sold during the 2005-2007 period. IPC anticipates realizing approximately 14,500 excess SO₂ emission allowances annually for the near future. Tighter emission restrictions are expected in the long term which may cause IPC to use more emission allowances for its own requirements and reduce the annual amount of excess emission allowances.

Oregon: 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 estimated Oregon's jurisdictional share of excess power supply costs to be \$5.7 million. This amount is currently estimated to be \$7.7 million. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. IPC is awaiting an order from the OPUC.

Table of Contents

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007. IPC requested authorization to defer an estimated \$3.3 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. A settlement agreement was reached with the OPUC Staff and the Citizens' Utility Board in the amount of \$2 million. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. The settlement stipulation was approved by the OPUC on December 13, 2007.

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. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2000 and 2001, which is discussed further under LEGAL AND ENVIRONMENTAL ISSUES - Western Energy Proceeding at the FERC. Full recovery of the 2001 deferral is not expected until 2009. The 2006-2007 and the 2007-2008 deferrals would have to be amortized sequentially following the full recovery of the 2001 deferral.

Oregon Power Cost Recovery Mechanism: On August 17, 2007, IPC filed an application with the OPUC requesting the approval of a power cost recovery mechanism similar to the Idaho PCA. A joint stipulation was filed with the OPUC on March 14, 2008, and the OPUC approved the stipulation on April 28, 2008.

The new mechanism allows IPC to recover excess net power supply costs in a more timely fashion than through the existing deferral process. The mechanism differs from the Idaho PCA in that it reestablishes the base net power supply costs annually. In Idaho, the base net power supply costs are set by a general rate case.

The new regulatory mechanism has two parts: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU has two components: the October Update, where each October IPC will calculate its estimated normalized net power supply expenses for the following April through March test period, and the March Forecast, where each March IPC will file a forecast of its normalized 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 will be adjusted to reflect costs calculated in the APCU.

The PCAM is a true-up to be filed annually in February beginning in 2009. The filing will calculate 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 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, with new combined rates effective each June 1.

On October 6, 2008, the OPUC provided an order clarifying that the PCAM is a deferral under the Oregon statute. IPC expects that deferrals under the PCAM component will be subject to the six percent limitation on annual amortization discussed above. IPC had \$3.8 million deferred under the PCAM at September 30, 2008.

Table of Contents

On October 29, 2007, IPC filed the October Update portion of its 2008 APCU with the OPUC reflecting the estimated net power supply expenses for the April 2008 through March 2009 test period. On March 24, 2008, IPC submitted testimony to the OPUC revising its calculation of the October Update to conform to the methodology agreed to by the parties in the stipulation. IPC also submitted the March Forecast, reflecting expected hydroelectric generating conditions and forward prices for the April 2008 through March 2009 test period. The expected power supply costs of \$150 million represented an increase of approximately \$23 million over the October Update.

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 results in a \$4.8 million, or 15.69 percent, increase in Oregon revenues.

On October 23, 2008, IPC filed the October Update portion of its 2009 APCU with the OPUC. The filing reflects that revenues associated with IPC's base net power supply costs would be increased by \$0.8 million over the previous October Update, an average 2.4 percent increase. The October Update will be combined with the March Forecast portion of the 2009 APCU, with final rates expected to become effective on June 1, 2009.

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

On March 14, 2008, IPC filed an application requesting a \$2.4 million rate reduction under the FCA pilot program for the net over-recovery of fixed costs during 2007. On May 30, 2008, the IPUC approved the rate reduction of \$2.4 million to be distributed to residential and small general service customer classes equally on an energy used basis during the June 1, 2008, through May 31, 2009, FCA year. IPC deferred \$1.7 million of FCA net under-recovery of fixed costs during the nine months ended September 30, 2008.

On March 14, 2008, IPC filed an application with the IPUC requesting an increase to its Energy Efficiency Rider (Rider), which is the chief funding mechanism for IPC's investment in conservation, energy efficiency and demand response programs. IPC proposed an increase from 1.5 percent to 2.5 percent of base revenues, or to approximately \$17 million annually, effective June 1, 2008. The application also sought authorization to eliminate the current funding caps for residential and irrigation customers, which is expected to result in more equitable cost recovery between customer classes, and authorization to utilize Rider funding to support customer programs aimed at the installation of small-scale renewable energy projects.

On May 30, 2008, the IPUC approved IPC's application to increase the Rider from 1.5 percent to 2.5 percent of base revenues, effective June 1, 2008, and approved IPC's request to eliminate the caps on the Rider for residential and irrigation customers. The IPUC denied IPC's request to utilize Rider funding to support customer programs aimed at the installation of small-scale renewable energy projects, but directed IPC to work with the IPUC Staff and other interested parties to develop a renewable energy program and submit it to the IPUC for approval.

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. This request was filed in conjunction with the October 3, 2008 application discussed below in Advanced Metering Infrastructure (AMI).

Table of Contents

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 may be enhanced to allow for the collection of data in support of 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 has entered into a number of contracts for materials and resources to allow for the AMI implementation to commence in late 2008. IPC intends to install this technology for approximately 99 percent of all customers in its service territory by the end of 2011. The executed contracts do not obligate IPC for any level of purchases and specifically allow IPC to cancel the contracts in the event that appropriate regulatory treatment regarding cost recovery is not granted.

On August 5, 2008, IPC filed an application with the IPUC requesting a Certificate of Public Convenience and Necessity for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. In its application, IPC estimated the three year investment in AMI to be \$71 million. The 2009 revenue requirement impact of the AMI deployment is estimated to be \$12.2 million. The effect on rates will be addressed in subsequent proceedings after a deployment plan is approved by the IPUC. The application will be processed through modified procedure with comments due December 9, 2008.

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. IPC's AMI deployment schedule calls for the replacement of the Oregon service-territory meters around October 2010. Under the proposed method, the existing meters will be fully depreciated prior to their removal from service. The estimated balance of plant in service at December 31, 2008, attributable to the existing meters is \$1.4 million. The approval of this application would result in an increase of \$0.8 million for 2009 in both rates and depreciation expense. This increase would be partially offset by the request for revised depreciation rates filed in the same application and discussed above in Depreciation Filings.

Idaho Pension Expense Order

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 and account for pension expense under SFAS 87, *Employers' Accounting for Pensions*, 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. The deferral of pension expense did not begin until \$4.1 million of past contributions still recorded on the balance sheet at December 31, 2006, were expensed. For 2007, approximately \$2.8 million was deferred to a regulatory asset beginning in the third quarter. During the nine months ended September 30, 2008, \$5.9 million of pension expense was deferred. IPC did not request a carrying charge on the deferral balance.

Revised Statement of Policy and Code of Conduct

On April 21, 2008, the IPUC approved IPC's Revised Statement of Policy and Code of Conduct covering transactions between IPC and subsidiaries of IDACORP. The Code of Conduct is designed to prescribe conduct between IPC and an affiliate, avoid issues of self-dealing and provide a framework to determine if cost recovery for affiliate transactions should be included in rates.

Table of Contents

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, 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 was the WP-07 supplemental rate case. The BPA issued the Final Record of Decision (ROD) on September 22, 2008 in this case. The ROD continues to reflect no residential exchange benefits for IPC's residential and small farm customers in the foreseeable future. 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.

Open Access Transmission Tariff (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 FERC Form 1 data. The formula rate request included a rate of return on equity of 11.25 percent. Effective June 1, 2006, the FERC accepted rates for IPC amounting to an annual revenue increase of \$11 million based upon 2004 test year data. The rates were accepted 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 the estimated annual revenue increase to approximately \$8.2 million based on 2004 test year data. Approximately \$1.7 million collected in excess

of these new rates between June 1, 2006, and July 31, 2007, was refunded with interest to customers in August 2007.

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. IPC has appealed the Initial Decision to the FERC and is awaiting a final FERC order. If implemented, the Initial Decision would reduce the estimated annual revenue increase (based on 2004 test year data) to approximately \$6.8 million, and IPC would make additional refunds, including interest, of approximately \$5 million for the June 1, 2006, through September 30, 2008, period. IPC has reserved this entire amount. IPC expects to pursue recovery of amounts not received pursuant to a final order in this proceeding through additional proceedings at the FERC or through the state ratemaking process.

On August 28, 2008, IPC filed its informational filing with the FERC that contains the annual update of the formula rate based on the 2007 test year. The new rate included in the filing is \$18.88 per kW-year, a decrease of \$0.85 per kW-year, or 4.3 percent. The impact of this rate decrease on IPC's revenues will depend on transmission volume sold, which can be highly variable. In 2007, IPC had \$16 million of revenues from sales of transmission to others. New rates were effective October 1, 2008.

Regional Transmission Organization (RTO) costs: On April 30, 2008, the FERC issued an order amending the OATT formula rate to allow IPC to include RTO formation costs previously deferred. The new rates were effective May 1, 2008. The FERC-jurisdictional amount deferred was \$0.4 million and will be added to rate base and amortized over five years. The impact on the OATT rate was an increase from \$19.31 per kW-year to \$19.73 per kW-year, or 2.2 percent until October 1, 2008, when the new rates from the annual update discussed above became effective.

Table of Contents

Northern Tier Transmission Group

On July 17, 2008, the FERC issued an order accepting IPC's compliance filing, subject to modifications, regarding the Attachment K transmission planning requirements of Order No. 890. The FERC directed IPC to make further compliance filings within 90 days to address these modifications. IPC has made these additional filings with the FERC. The Attachment K planning processes incorporate local, subregional, and regional transmission planning into IPC's OATT, under which IPC has been operating since the December 7, 2007, initial filing date. The order and subsequent compliance filings do not constitute a material change in planning obligations and are not expected to have a significant impact on IPC's financial results.

Transmission Projects

The transmission projects discussed below will be used both by wholesale transmission customers and to serve native load consistent with IPC's OATT. These facilities will be subject to both the FERC and state public utility commission regulation and ratemaking policies.

Gateway West Project: IPC and PacifiCorp are jointly exploring the Gateway West Project to build two 500-kV lines between the Jim Bridger plant in Wyoming and Boise. The lines would increase electrical transmission capacity across southern Idaho in response to increasing customer demand and growth, along with other transmission service requests. The regional planning report has been submitted to the Western Electricity Coordinating Council (WECC) for review as part of the ratings process. A review team has been established from members of the WECC to analyze the impact of the project on the existing system. When the study is complete, necessary modifications will be made to the engineering design and the final rating will be obtained prior to the beginning of construction. Planning and project management personnel for both companies have begun the initial phases of this project. IPC and PacifiCorp have a cost sharing agreement for expenses associated with the analysis work of the initial phases. It is expected that the majority of the project would be completed between 2012 and 2014 depending on the timing of rights-of-way acquisition, siting and permitting, and construction sequencing. If the project is constructed, IPC estimates that its share of project costs would be between \$800 million and \$1.2 billion.

Boardman-Hemingway Line: Consistent with the 2006 IRP and requirements and requests of other transmission customers, IPC is exploring alternatives for the construction of a 500-kV line between southwestern Idaho and the Northwest. The Boardman-Hemingway Line is expected to relieve existing congestion, capacity and reliability constraints and to allow for the delivery of up to 1,500 MW of additional energy to target service areas, principally in Idaho and Oregon, along with other eastward and Pacific Northwest locations. If built, this line could be in service as early as 2012. The current project schedule indicates a likely in-service date of June 2013. The existing transmission station at the Boardman power plant in Oregon would serve as the northwest terminal of the project. The Idaho terminal would be the proposed Hemingway Station located in the vicinity of Melba and Murphy, Idaho on the south side of the Snake River near Boise. IPC and a number of other utilities with proposed regional transmission projects

in the Northwest have signed a letter agreeing to coordinate technical studies, which have begun. The regional planning report has been submitted to the WECC for review as part of the ratings process. On August 28, 2008, IPC filed a notice of intent (NOI) with the Oregon Department of Energy to apply for a site certificate for the proposed line. On October 3, 2008, IPC filed a project proposal with the NTTG Cost Allocation Committee requesting approval of the allocation of costs and benefits for the project. IPC does not expect any recommendation or approval by the NTTG until the second half of 2009. Other planning and project management activities are underway.

Table of Contents

IPC stated in its proposal that the line would be approximately 300 miles long, but it could be longer or shorter depending on the route selected. Current total cost estimates for the project (including rights-of-way, permit and substation interconnection costs) are approximately \$600 million. Final costs, routes, construction schedules, line miles and transmission capacity for the Boardman-Hemingway Line will be determined as the NOI and other processes are completed. IPC's share of the total line costs will also depend upon whether and to what extent ownership partners participate in the line and amounts contributed by third-party purchasers of capacity on the line. IPC has received inquiries about participating in this project from other parties, and continues to explore opportunities to partner with other entities for up to fifty percent of the project. On October 22, 2008, IPC and Portland General Electric (PGE) signed a memorandum of understanding (MOU) as the basis for cooperation on the Boardman-Hemingway Line and PGE's proposed Southern Crossing 500kV project. The MOU provides the two utilities an opportunity to integrate a portion of the proposed transmission lines if both projects move forward.

Integrated Resource Plan

IPC's 2006 IRP previewed IPC's load and resource situation for the next twenty years, analyzed potential supply-side and demand-side options and identified near-term and long-term actions. In June 2008, IPC provided an update on the status of the IRP to both the IPUC and OPUC. IPC has also begun preparing the 2009 IRP, which is expected to be filed with the IPUC and OPUC in June 2009. IPC continually evaluates the resource plan and adjusts it to reflect changes in technology, economic conditions, anticipated resource development and regulatory requirements. Several items from the 2006 IRP have been updated, including:

Geothermal Agreement: The Raft River Geothermal Power Plant Unit #1, which is owned and operated by U.S. Geothermal and located in southern Idaho, began delivering energy to IPC in October 2007 under a PURPA contract which was limited to 10 MW on a monthly basis. On January 9, 2008, the IPUC approved a power purchase agreement for 13 MW from the project, which was bid into IPC's 2006 Geothermal RFP. Concurrent with the approval of the new contract, the existing PURPA contract was terminated.

In response to IPC's 2006 RFP, U.S. Geothermal also proposed an additional 6.5 MW at the Raft River site and 26 MW from two units at the Neal Hot Springs site located in eastern Oregon. U.S. Geothermal is continuing development work on these additional sites; however, there have been delays in the development process and those resources are not expected to meet the 2009 on-line date identified in the 2006 IRP. Contract discussions between IPC and U.S. Geothermal are on-going and IPC is not able to predict the outcome of these discussions.

Geothermal RFP: On January 22, 2008, IPC released an RFP for 50 to 100 MW of geothermal energy. While additional geothermal resources were not included in the 2006 IRP for this time frame, the development of PURPA wind and combined heat and power projects has been slower than anticipated. If competitively priced geothermal resources are available, they may help to meet future resource needs. Proposals were received on March 14, 2008.

IPC expects to announce the results of this RFP in the fourth quarter of 2008.

Combined Heat and Power (CHP) RFP: The 2006 IRP included 50 MW of CHP coming on-line in 2010. CHP development at customers' facilities has not progressed as anticipated in the 2006 IRP. Since CHP development has been less than anticipated, IPC may release an RFP in late 2008.

2012 Baseload RFP: In light of the decision to no longer pursue a conventional coal resource in 2013 as identified in the 2006 IRP, on April 1, 2008, IPC issued an RFP for between approximately 250 and 600 MW of dispatchable, physically delivered firm or unit contingent energy to be acquired under power purchase or tolling agreements. A tolling agreement is an arrangement where one party owns, operates and maintains the generating facility and the other party provides fuel, pays capacity charges and receives the contracted output from the project including energy, capacity and ancillary services. The timing of this addition was also accelerated to 2012 to meet forecast deficits resulting from changes in the resource portfolio not anticipated in the 2006 IRP. In June 2008, IPC notified bidders that the RFP quantity had been revised to approximately 300 MW. IPC submitted a self-build proposal for a combined-cycle combustion turbine which will serve as a benchmark and will compete in the evaluation process. Proposals were received and are being evaluated.

Relicensing of Hydroelectric Projects

This section summarizes and updates the discussion of relicensing projects in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2007, and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008, and June 30, 2008.

IPC, like other utilities that operate non-federal 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.

Table of Contents

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 \$102 million and \$4 million for HCC and Swan Falls, respectively, were included in construction work in progress at September 30, 2008.

Hells Canyon Complex: The most significant ongoing relicensing effort is the HCC, which provides approximately two-thirds of IPC's hydroelectric generating capacity and 40 percent of its total generating 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 is reviewing the final EIS and expects to file comments with the FERC in late 2008 or early 2009.

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 (CWA), with the States of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. 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. On September 21, 2007, IPC submitted its draft license application to the FERC for public review and comment. The draft contains project-specific information and the results of environmental studies designed to determine project effects. Comments were received from the agencies and one Native American tribe and on February 19, 2008, a joint meeting was held to address the comments and attempt to resolve areas of disagreement over study results and proposed mitigation measures. On June 26, 2008, IPC filed a final license application with the FERC. On July 9, 2008, in conformance with applicable regulations, the FERC issued a Notice of Application Tendered for Filing with the Commission, Soliciting Additional Study Requests, and Establishing Procedural Schedule for Relicensing and a Deadline for Submission of Final Amendments. Pursuant to that notice, state and federal resource agencies, Native American tribes or other interested parties were to file additional study requests with the FERC by August 26, 2008. Additional study requests were filed by the Shoshone-Bannock Tribes and the U.S. Fish and Wildlife Service. IPC filed responses to these requests on September 26 and 29, 2008, respectively. The FERC is still considering the requests from the Shoshone-Bannock Tribes and the U.S. Fish and Wildlife Service. On October 7, 2008, IPC received a request from the FERC to provide clarification and additional information on the Swan Falls license application. IPC is in the process of responding to this request.

Table of Contents

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 the fourth quarter of 2008. In conjunction with the license amendment application, IPC has filed a water rights application which is currently being reviewed by the IDWR.

LEGAL AND ENVIRONMENTAL ISSUES:

Legal and Other 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, 2007 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008, 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, which resulted in energy shortages 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, the structure and content of the FERC's market-based rate regime, show cause orders with respect to contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in any one of 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 or estimate the impact they may have on their consolidated financial positions, results of operations or cash flows.

California Refund: 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. That plan included the potential for orders directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund the portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. On July 25, 2001, the FERC issued an order initiating the California Refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC. A number of other parties, representing substantially less than the majority of potential refund claims, chose to opt out of the settlement. After consideration of comments, the FERC approved the Offer of Settlement on May 22, 2006.

Table of Contents

On February 3, 2004, the FERC directed the California Independent System Operator (Cal ISO) to provide status reports with respect to its progress in calculating refunds, fuel and emissions allowance offsets to refunds and interest. The process of performing the calculations has engaged the Cal ISO for more than four years. On May 16, 2008, the Cal ISO published its Forty-First Status Report and on September 3, 2008, the Cal ISO published its Forty-Second Status Report. The Forty-First and Forty-Second Status Reports are essentially similar. In the Forty-Second Status Report, the Cal ISO stated its intention not to issue another status report until the FERC had provided guidance on a series of unresolved questions which the Cal ISO considered to be necessary before it completes its calculations. Included among these unresolved questions are three pending alternative dispute resolution matters, several allocation questions and several questions regarding FERC treatment of non-jurisdictional entities exempted from refund obligations, including questions about the relationship of FERC-approved settlements to the allocation to net refund recipients of refund shortfalls otherwise associated non-jurisdictional entities. The Cal ISO intends to complete work on its calculations after the FERC provides the requested guidance.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the IE and IPC/California Parties settlement. On October 5, 2006, the FERC denied the Port of Seattle's request for rehearing and on October 24, 2006, the Port of Seattle petitioned the Ninth Circuit for review of the FERC orders approving the settlement. On October 25, 2007, the Ninth Circuit lifted the stay as to the Port of Seattle's appeal along with two other cases with which the Port of Seattle's petition remains consolidated and severed the three cases from the remainder of the consolidated cases. Briefs by all participants have now been filed. Oral argument is scheduled for December 16, 2008. IE and IPC intend to vigorously defend their positions in this proceeding, but are unable to predict the outcome of this matter or estimate the impact it may have on their consolidated financial positions, results of operations or cash flows.

Market Manipulation: As part of the California and Pacific Northwest Refund proceedings 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 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior (partnership) in violation of the Cal ISO and CalPX Tariffs. On October 16, 2003, IE and IPC reached agreement with the FERC Staff on two orders commonly referred to as the gaming and partnership show cause orders. The FERC staff submitted a motion to the FERC to dismiss the partnership proceeding, which was approved by the FERC in an order issued on January 23, 2004. The gaming settlement was approved by the FERC on March 4, 2004.

Some parties have sought review of what they claim are the excessively narrow or excessively broad scope of the show cause orders, and the Ninth Circuit has consolidated those claims with the other matters and is holding them in abeyance. The Port of Seattle is the only party to appeal the orders of the FERC approving the gaming settlement. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial positions, results of operations or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing another 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. A FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001, concluding that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. On December 19, 2002, the FERC reopened the proceeding to allow the submission of additional evidence related to alleged manipulation of the power market by market participants. Parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. On June 25, 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit. On August 24, 2007, the Ninth Circuit issued an opinion in the appeal, 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 submitted by the petitioners for the period January 1, 2000 to June 21, 2001 would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources proceeding. A number of parties have sought rehearing of the Ninth Circuit's decision. Grays Harbor terminated its participation in the case when Grays Harbor and IPC reached a settlement. IE and IPC intend to vigorously defend their positions in this proceeding, but are unable to predict the outcome of this matter or estimate the impact it may have on their consolidated financial positions, results of operations or cash flows.

Table of Contents

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006, regarding the FERC's decision not to require repricing of certain long-term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. On June 26, 2008, the U.S. Supreme Court issued a decision in one of these cases, *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County* (No. 06-1457) (Snohomish), and 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 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.

This 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. IPC and IE have asserted the Mobile-Sierra doctrine as a defense to the claims asserted in the Pacific Northwest proceeding, involving spot market contracts in an allegedly dysfunctional market. IDACORP, IPC and IE are unable to predict how the FERC will rule on Snohomish on remand or how this decision will affect the outcome of the Pacific Northwest proceeding.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the U.S. District Court for the District of Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal-fired plant (Plant) in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured in the flue gas of a power plant. A formal answer to the complaint was filed by PacifiCorp on April 2, 2007, in which PacifiCorp denied almost all of the allegations and asserted a number of affirmative defenses. IPC is not a party to this proceeding but has a one-third ownership interest in the Plant. PacifiCorp owns a two-thirds interest and is the operator of the Plant. The complaint alleges thousands of opacity permit limit violations by PacifiCorp and seeks a declaration that PacifiCorp has violated opacity limits, a permanent injunction ordering PacifiCorp to comply with such limits, civil penalties of up to \$32,500 per day per violation and the plaintiff's costs of litigation, including reasonable attorney fees.

Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity compliance status of the Plant. The court has not yet ruled on these motions. On March 13, 2008, the District Court canceled the original trial date of April 21, 2008, but did not schedule a new trial date. On July 7, 2008, the plaintiffs filed a motion requesting the court to schedule a date for oral argument on the pending motions for summary judgment. On July 17, 2008, PacifiCorp filed an opposition to plaintiffs' motion based on the court's order on Initial Pretrial Conference, which stated that dispositive motions will be decided on the briefs without oral argument. The court has yet to rule on plaintiffs' motion. IPC continues to monitor the status of this matter but 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, Sierra Club 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 power 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. The complaint seeks a declaration that PGE has violated opacity limits, a permanent injunction ordering PGE to comply with such limits, injunctive relief requiring PGE to remediate alleged environmental damage and ongoing impacts, civil penalties of up to \$32,500 per day per violation and the plaintiffs' cost of litigation, including reasonable attorney fees. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant. PGE owns 65 percent and is the operator of the plant.

Table of Contents

PGE has not answered or otherwise responded to the complaint. IPC intends 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 was accidental and caused by high winds.

IPC has received claims from a number of the homeowners and their insurers and is continuing its investigation of these claims. 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 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 6 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, 2007 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008.

Idaho Water Management Issues: From 2000 through 2005, and throughout 2007 and the year-to-date 2008, below normal precipitation and stream flows 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 Idaho Department of Water Resources (IDWR), demanding that it manage ground water withdrawals pursuant to the prior

appropriation doctrine of first in time is first in right and curtail junior ground water rights that are depleting the aquifer and affecting flows to senior surface water rights. These delivery calls have resulted in several administrative actions before the IDWR 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.

Table of Contents

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). In 1990, IPC entered into a contract with the owners relating to the construction and operation of a power plant at Milner Dam. To facilitate the rehabilitation of the Milner dam, IPC and NSCC/TFCC jointly filed for, and were issued, a FERC license for a hydroelectric project at the dam. IPC constructed and operates the project, and participated in the financing of the dam rehabilitation. NSCC and TFCC filed an application for a water right for the project and were issued an approved water right permit by the IDWR in 1993. The permit contained a condition subordinating the water right to all consumptive beneficial uses of water, other than hydropower and groundwater recharge. Since the issuance of the permit, the NSCC and TFCC have delivered water to and IPC has operated the Milner project under the FERC license. On October 20, 2008, the IDWR issued a water right license for the project that changed the subordination condition in the permit by deleting the reference to groundwater recharge, thereby subordinating the water right to groundwater recharge. On November 4, 2008, NSCC and TFCC filed a petition for hearing with IDWR contesting the change in the subordination condition. IDWR has not taken any action on the petition. IPC is monitoring but is unable to predict the outcome of the administrative action.

IPC, together with other interested water users and state interests, also continues to explore and encourage the development of a long-term management plan that will protect the ESPA and the Snake River from further depletion. On February 14, 2007, the Idaho Water Resource Board (IWRB) presented the framework for an ESPA management plan to the Idaho Legislature recommending the development of a Comprehensive Aquifer Management Plan (CAMP). The proposed goal of the CAMP is to sustain the economic viability and social and environmental health of the ESPA by adaptively managing a balance between water use and supplies. Through House Concurrent Resolution 28 and House Bill 320, the 2007 Idaho Legislature appropriated funds and directed the IWRB to proceed with the development of the CAMP. Pursuant to the IWRB recommendation in the CAMP Framework, an advisory committee has been established to make recommendations to the IWRB on the development of the CAMP. IPC sits on the CAMP advisory committee and will be working with the IWRB on the development of the CAMP. The advisory committee expects to submit recommendations on the CAMP to the IWRB in the fourth quarter of 2008.

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. The initiation of the SRBA resulted from the Swan Falls Agreement, an agreement entered into by IPC and the Governor and Attorney General of Idaho in October 1984 to resolve litigation relating to IPC's water rights at its Swan Falls project. IPC has filed claims to its water rights for hydropower and other uses in the SRBA. Other water users in the basin have also filed claims to water rights. Parties to the SRBA may file objections to water right claims that adversely affect or injure their claimed water rights and the Idaho District Court for the Fifth Judicial District, which has jurisdiction over SRBA matters, then adjudicates the claims and objections and enters a decree defining a party's water rights. IPC has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. One such claim involves a notice of claim of ownership filed on December 22, 2006, by the State of Idaho, for a portion of the water rights held by IPC that are subject to the Swan Falls Agreement.

On May 10, 2007, in order to protect its claims and the availability of water for power purposes at its facilities, and in response to the claim of ownership filed by the State of Idaho, IPC filed a complaint and petition for declaratory and injunctive relief regarding the status and nature of IPC's water rights and the respective rights and responsibilities of the parties under the Swan Falls Agreement. The complaint was filed in the Idaho District Court for the Fifth Judicial District, the court with jurisdiction over the SRBA, against the State of Idaho, the Governor, the Attorney General, the IDWR and the Director of the IDWR.

In conjunction with the filing of the complaint and petition, IPC filed motions with the court to stay all pending proceedings involving the water rights of IPC and to consolidate those proceedings into a single action where all issues relating to the Swan Falls Agreement can be determined.

IPC alleged in the complaint, among other things, that contrary to the parties' belief at the time the Swan Falls Agreement was entered into in 1984, the Snake River basin above Swan Falls was over-appropriated and as a consequence there was not in 1984, and there currently is not, water available for new upstream uses over and above the minimum flows established by the Swan Falls Agreement; that because of this mutual mistake of fact relating to the over-appropriation of the basin, the Swan Falls Agreement should be reformed; that the state's December 22, 2006, claim of ownership to IPC's water rights should be denied; and that the Swan Falls Agreement did not subordinate IPC's water rights to aquifer recharge.

Table of Contents

On April 18, 2008, the court issued a Memorandum Decision and Order on Cross-Motions for Summary Judgment upholding the Swan Falls Agreement. Under the Swan Falls Agreement, water rights in excess of the minimum flows established by the agreement are held in trust by the State of Idaho for the use and benefit of IPC and the people of the State of Idaho. Water above these minimum flows is available for subsequent consumptive beneficial uses that are approved in accordance with state law. The court further held that to the extent that the state is not meeting the minimum flows or it is anticipated that the minimum flows will not be met, IPC's water rights that are held in trust are not available for subsequent appropriations and that any appropriations already in place may be subject to curtailment in order to meet the minimum flows. The court found that it was not necessary to address the issue of mutual mistake of fact relating to the over-appropriation of the basin because it found that it was water rights that were the subject of the trust arrangement and not the water itself. The court also stated that issues relating to water availability relate to the administration of water rights and should be addressed, as necessary, in an administrative action before the IDWR.

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The State of Idaho and IPC are now in the process of completing discovery, and have submitted summary judgment motions on the recharge issue. The court has scheduled a hearing for December 4, 2008, for arguments on the summary judgment motions. IPC is unable to predict how the court will rule on the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. Based upon recent developments, however, resolution of that issue is not expected to have a significant effect on the availability of water to IPC's hydropower facilities. IPC is cooperating with the State of Idaho and other water users through an advisory committee in the development of the CAMP to protect and enhance water levels in the Eastern Snake Plain Aquifer (ESPA) and the connected Snake River. Many CAMP committee members had early expectations that groundwater recharge would be a significant component of the plan. However, further study and review has revealed that significant groundwater recharge is not feasible due to the complex hydrology of the ESPA, the lack of infrastructure, and the requirement of compliance with water quality and other environmental standards.

IPC has also filed two actions in federal court against the United States Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River. In 1923, IPC and the United States entered into a contract that facilitated the development of the American Falls Reservoir by the United States on the Snake River in southeast Idaho. This 1923 contract entitles IPC to 45,000 acre-feet of primary storage capacity in the reservoir and 255,000 acre-feet of secondary storage that was to be available to IPC between October 1 of any year and June 10 of the following year as necessary to maintain specified flows at IPC's Twin Falls power plant below Milner Dam. IPC believes that the United States has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, IPC filed an action in the U.S. District Court of Federal Claims in Washington, D.C. on October 15, 2007 to recover damages from the United States for the lost generation resulting from the reduced flows. On September 30, 2008, IPC filed an amended complaint in which IPC seeks, in addition to damages for breach of the 1923 contract, a prospective declaration of contractual rights so as to prevent the United States from continued failure to fulfill its contractual and fiduciary duties to IPC. On October 2, 2008, the court set a discovery schedule requiring that discovery be completed and pre-trial motions filed by October 1, 2009. The court will then set the matter for trial. IPC is unable to predict the outcome of this action.

The second action was filed by IPC on October 16, 2007 in the U.S. District Court for the District of Idaho in Boise, Idaho for a declaration of parties' respective rights and obligations under the 1923 contract and to compel the United States to manage American Falls Reservoir and the Snake River federal reservoir system to ensure that IPC's contract right to secondary storage is fulfilled in the future. Subsequently, IPC and the United States agreed that the issues in this action could be addressed in the action filed in the U.S. District Court of Federal Claims. As a result, the complaint in the Federal Claims Court action was amended and on October 7, 2008, the U.S. District Court in Idaho approved a Stipulation of Dismissal filed by IPC and the United States dismissing, without prejudice, the action filed in the District Court of Idaho.

Table of Contents

Air Quality Issues

IPC owns two natural gas combustion turbine power plants and co-owns three coal-fired power plants that are subject to air quality regulation. The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. The coal-fired plants are: Jim Bridger (33 percent interest) located in Wyoming; Boardman (ten percent interest) located in Oregon; and North Valmy (50 percent interest) located in Nevada. The Clean Air Act establishes controls on the emissions from stationary sources like those owned by IPC. The Environmental Protection Agency (EPA) adopts many of the standards and regulations under the Clean Air Act, while states have the primary responsibility for implementation and administration of these air quality programs. IPC continues to actively monitor, evaluate and work on air quality issues pertaining to the Clean Air Mercury Rule (CAMR), possible legislative amendment of the Clean Air Act, emerging greenhouse gas and climate change programs at the federal, regional and state levels, New Source Review (NSR) permitting, National Ambient Air Quality Standards (NAAQS), and Regional Haze Best Available Retrofit Technology (RH BART). Low nitrogen oxide (NO_x) burner technology and mercury continuous emission monitoring systems (mercury CEMS) installations are progressing at all three coal-fired power plants.

National Ambient Air Quality Standards: In March 2008, the EPA promulgated a final regulation which revised the 8-hour ozone NAAQS. For the primary (health-based) standard, the EPA lowered the standard from 0.08 parts per million (ppm) to 0.075 ppm. Under the EPA's final rule, states must make recommendations to the EPA by March 2009 for areas to be designated attainment, nonattainment and unclassifiable. Several states, environmental organizations and private parties have challenged the EPA's regulations. The impact of the new standard will not be known until data is collected, analyzed, and released to the public, the judicial appeals are completed and the associated regulatory programs are promulgated and implemented. The EPA is expected to make final air quality designations by March 2010. On May 8, 2008, the EPA issued a final rule implementing the NSR program for emissions of particulate matter of less than 2.5 micrometers in diameter (PM_{2.5}). This rule establishes the framework for requiring preconstruction permit review of PM_{2.5} emissions from new or modified major stationary sources such as the power plants owned by IPC. The impacts of the PM_{2.5} NSR standards on IPC will not be known until individual states adopt revised plans and regulations to implement these federal requirements and they become applicable to IPC due to activities at its power plants.

Clean Air Interstate Rule (CAIR): The CAIR, issued by the EPA on March 10, 2005, establishes a permanent cap on emissions of NO_x and SO₂ primarily from power plants in 28 eastern states and the District of Columbia. While the CAIR does not apply to any of the power plants owned by IPC, it is an important rule for the electric utility industry because of its broad applicability and its close relation to the CAMR. The CAIR was subjected to legal challenges by a number of states, industry, and environmental groups. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAIR. On September 24, 2008, the EPA petitioned the U.S. Court of Appeals for the D.C. Circuit to reconsider its ruling to vacate the CAIR. The court has not yet ruled on the EPA's petition. On October 21, 2008, the court issued an order giving the parties who challenged the CAIR 15 days to address whether they want the court to stay its decision and allow the CAIR to remain in effect until such time as the EPA creates a

new rule in response to the court's decision. A possible legislative enactment of the CAIR was discussed in Congress. The potential impacts of this court ruling will not be fully understood until any future appeals are resolved or until such time as Congress, the EPA and/or individual states respond to the court's ruling.

Clean Air Mercury Rule: The CAMR, issued by the EPA on March 15, 2005, limits mercury emissions from new and existing coal-fired power plants and creates a market-based cap-and-trade program that will permanently cap utility mercury emissions. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAMR and remanded it back to the EPA for reconsideration consistent with the court's interpretation of the Clean Air Act. On March 24, 2008, the EPA petitioned the U.S. Court of Appeals for the D.C. Circuit to reconsider its decision to overturn the CAMR, which was rejected by the court on May 20, 2008. On September 17, 2008, the EPA filed a request with the U.S. Supreme Court to review the D.C. Circuit's decisions. The Supreme Court has not yet ruled on the EPA's request. The impact of the court's decision will not be known until the judicial appeals process has been completed or until such time as the EPA develops a new regulation in response. It is possible that the decision to remand the CAMR back to the EPA for reconsideration could result in the EPA developing maximum achievable control technology standards for mercury emissions from coal-fired power plants. It also is possible that the court's decision could result in changes to the mercury reductions required by the states in which IPC has partial ownership interests in coal-fired power plants. IPC is unable to predict at this time what actions the EPA or states may take in response to the court's decision or any resulting impacts to IPC.

Table of Contents

Regional Haze Best Available Retrofit Technology: In accordance with federal regional haze rules, 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. 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 North Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule. On August 20, 2008, the ODEQ issued a draft RH BART proposal for the Boardman plant that, if adopted, would require the installation of significant emission controls beginning in 2011. The ODEQ plans to finalize a RH BART determination for the Boardman plant in January 2009 with the intent of adopting a final rule in April 2009. The pollution control requirements proposed by the ODEQ are estimated to cost approximately \$59 million (IPC share). Under the proposal approximately \$40 million (IPC share) will need to be spent by 2014 with an additional \$19 million (IPC share) by 2017. In addition, IPC and Pacificorp have been meeting with the WDEQ to discuss potential RH BART requirements for the Jim Bridger plant. Discussions with the WDEQ are ongoing and IPC continues to monitor RH BART processes at both the Jim Bridger and Boardman plants.

Greenhouse Gases: IPC continues to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas (GHG) regulations and judicial decisions that would affect electric utilities. Such regulations could increase IPC's capital expenditures and operating costs and reduce earnings and cash flows. At the national level, numerous GHG bills were introduced in the U.S. Senate and House of Representatives during 2007 and 2008, including the Climate Security Act of 2008 (S. 3036), which was debated on the Senate floor in June 2008 but not voted on. In addition, the Chairman of the House Committee on Energy and Commerce, and the Chairman of the House Subcommittee on Energy and Air Quality, released a discussion draft of federal GHG cap-and-trade legislation on October 7, 2008. A change of administration in January 2009 also is widely expected to spur proposals that could lead to the adoption of a mandatory federal program to reduce GHG emissions through an economy-wide cap-and-trade program or carbon tax.

The states of Arizona, California, Montana, New Mexico, Oregon, Utah and Washington, along with the provinces of British Columbia, Manitoba, Ontario and Quebec, Canada, have formed the Western Regional Climate Action Initiative (WCI). On August 22, 2007, the WCI partners released their regional goal to collectively reduce GHGs 15 percent below 2005 levels by 2020. The WCI partners have agreed to design a regional market-based multi-sector mechanism to help achieve the goal. On September 23, 2008, the WCI issued its design recommendations to reduce GHG emissions from the electricity generating industry. The recommendations by the WCI include a cap-and-trade program for the electricity generating industry which would apply to in-state electricity generators and the first jurisdictional deliverer of electricity into a WCI partner state. The states of Idaho, Nevada and Wyoming have not joined the WCI. It is possible that these and other states in which IPC owns fossil fuel-fired electricity generation facilities or sells electricity into could join the WCI in the future.

In April 2007, the U.S. Supreme Court issued its decision in *Massachusetts v. Environmental Protection Agency*, a case involving the EPA's authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act.

The decision, combined with stimulus from state, regional and federal legislative and regulatory initiatives, judicial decisions and other factors may lead to a determination by the EPA to regulate carbon dioxide emissions from stationary sources, including electricity generators. On March 27, 2008, the EPA announced that it would issue an advanced notice of proposed rulemaking (ANPR) to solicit public input on whether GHG emissions should be regulated from stationary sources. On April 2, 2008, Attorneys General from 17 states filed suit in the U.S. Court of Appeals for the D.C. Circuit requesting the court to require the EPA to rule within 60 days on whether carbon dioxide is a danger to public health or welfare and, therefore, subject to regulation under the Clean Air Act. On June 26, 2008, the court denied the request. On July 11, 2008, the EPA released its ANPR inviting public comment on the benefits and ramifications of regulating GHGs under the Clean Air Act. While the majority of current national, regional and state initiatives regarding GHG emissions contemplate market-based compliance programs, a determination by the EPA to regulate GHG emissions under the Clean Air Act could result in GHG emission limits on stationary sources that do not provide market-based compliance options such as cap-and-trade programs or emission offsets. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because new technologies for reducing carbon dioxide emissions from coal, including carbon capture and storage, are not yet proven. IPC will continue to monitor developments with respect to the possible regulation of GHG emissions from stationary sources under the Clean Air Act.

Table of Contents

In 2007, IPC's carbon dioxide emissions from IPC's electric power generation facilities were approximately 7.8 million tons, or 1,153 lbs/MWh (adjusted to reflect IPC's partial ownership in the Jim Bridger, Boardman and North Valmy facilities). At this time, IPC is unable to estimate the costs of compliance with potential national, regional or state GHG emissions reductions legislation or initiatives because these proposals are in the early stages of development and any final regulation, if adopted, could vary from current proposals. The actual impact of future regulation of GHG emissions on IPC's financial performance will depend on a number of factors, including but not limited to: (1) the geographic scope of any legislation or regulation (e.g., federal, regional, state); (2) the enactment date of the legislation or regulation and the compliance deadlines; (3) the type of any legislation or regulation (e.g., cap-and-trade, carbon tax, GHG emission limits); (4) the level of GHG reductions required and the year selected as a baseline for determining the amount or percentage of mandated GHG reductions; (5) the extent to which market-based compliance options are available; (6) the extent to which a facility would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the price and availability of offsets in the secondary market and (7) the availability and cost of carbon control technology.

Climate Change: IPC intends to continue to add non-carbon-producing resources to its resource portfolio and will continue to monitor the climate change debate, current climate change research, and recently enacted as well as proposed legislation to identify the potential impacts of global climate change on all aspects of its business. Long-term climate change could significantly affect IPC's business in a variety of ways, including but not limited to the following: (a) extreme weather events and changes in temperature, precipitation and snow pack conditions could affect customer demand and the amount and timing of hydroelectric generation and increase service interruptions, outages and operations and maintenance costs; and (b) legislative and/or regulatory developments related to climate change could affect plans and operations in various ways including placing restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of current carbon emitting generation resources in general. IPC cannot, however, quantify the potential impact of global climate change on its business at this time.

Renewable Portfolio Standards: Legislation to adopt a national renewable portfolio standard (RPS) has been introduced but not yet adopted by Congress. IPC expects debate to continue on a national RPS. IPC is not currently subject to state RPS in Idaho, however, IPC's operations in Oregon will be required to comply with a ten percent RPS beginning in 2025. It is possible that Idaho and other states in which IPC operates or sells power into could adopt RPS initiatives that would impact IPC. IPC will continue to monitor RPS developments but cannot, at this time, predict the impacts of state and federal RPS legislation on its business.

OTHER MATTERS:

Southwest Intertie Project

IPC began developing the SWIP in 1988. IPC's investment consists predominantly of a federal permit for a specific transmission corridor in Nevada and Idaho and also private rights-of-way in Idaho. The SWIP rights-of-way extend from Midpoint substation in south-central Idaho through eastern Nevada to the Dry Lake area northeast of Las Vegas, Nevada. In 2004 the Bureau of Land Management granted a five-year extension to begin construction of a proposed 500kV transmission line within the rights-of-way before December 2009. On March 31, 2005, IPC entered into an agreement with White Pine Energy Associates, LLC (White Pine), an affiliate of LS Power Development, LLC, which gave White Pine a three-year exclusive option to purchase the SWIP rights-of-way from IPC. The option could be exercised in part or as a whole.

On March 28, 2008, Great Basin Transmission, LLC (Great Basin), as successor in interest to White Pine, exercised its option to purchase the southern portion of the SWIP rights-of-way from IPC. This sale closed during the second quarter of 2008, and resulted in a net pre-tax gain to IPC of approximately \$3 million. IPC and Great Basin also extended the term for exercise of the option on the northern portion of the SWIP rights-of-way from March 31, 2008, to December 31, 2008.

Table of Contents

Hoku Special Contract

On September 17, 2008, IPC entered into an Electric Service Agreement (ESA) with Hoku Materials, Inc. (Hoku) to provide electric service to Hoku's polysilicon production facility under construction in Pocatello, Idaho. The initial term of the ESA is four years beginning on June 1, 2009, with automatic renewal after June 1, 2013 unless either party gives 12 months prior written notice of termination. The amounts of power IPC will make available to Hoku are fixed and vary by season. IPC's maximum demand obligation during the initial term is 82 MW; however, Hoku may increase or decrease its total demand to between 25 MW and 175 MW after June 1, 2013. The purchase rates in the ESA are based on a combination of embedded cost tariff rates and marginal costs and are subject to change by action of the IPUC. IPC's revenues under the ESA will vary depending upon the level of demand from Hoku. If Hoku maximizes its demand during the initial four-year term of the ESA, IPC's revenues under the ESA would total approximately \$125 million for that period. The ESA is subject to prior review and approval by the IPUC. IPC filed an application to approve the ESA with the IPUC on October 24, 2008.

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, 2007, and have not changed materially from that discussion.

Adopted Accounting Pronouncements

SFAS 157: IDACORP and IPC partially adopted the provisions of SFAS 157, *Fair Value Measurements* (SFAS 157) on January 1, 2008. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair

value measurements. FASB Staff Position 157-2 (FSP FAS 157-2) delayed the implementation of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The delay is intended to allow the FASB and constituents additional time to consider the effect of various implementation issues that have arisen, or that may arise, from the application of SFAS 157. In accordance with FSP FAS 157-2, IPC did not apply the provisions of SFAS 157 to asset retirement obligations. On October 10, 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*, which clarifies the application of SFAS 157, in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP was effective upon issuance, including prior periods for which financial statements had not been issued. The adoption of SFAS 157 and its related pronouncements did not have a material effect on IDACORP's or IPC's consolidated financial statements.

SFAS 159: IDACORP and IPC adopted the provisions of SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement 115* (SFAS 159) on January 1, 2008. SFAS 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities*, applies to all entities with available-for-sale and trading securities. IDACORP and IPC did not elect the fair value option for any existing eligible items, thus the adoption of SFAS 159 did not have a material effect on IDACORP's or IPC's consolidated financial statements.

FSP FIN 39-1: IDACORP and IPC adopted FASB Staff Position FIN 39-1 (FSP FIN 39-1), *Amendment of FASB Interpretation No. 39* (FIN 39) on January 1, 2008. FSP FIN 39-1 modifies FIN 39, *Offsetting of Amounts Related to Certain Contracts*, and permits reporting entities to offset receivables or payables recognized upon payment or receipt of cash collateral against fair value amounts recognized for derivative instruments that have been offset under a master netting arrangement. IDACORP and IPC have elected to offset these positions, which resulted in an immaterial net decrease to total assets and liabilities at September 30, 2008.

Table of Contents

EITF Issue No. 06-11: IDACORP and IPC adopted Emerging Issues Task Force Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11) on January 1, 2008. EITF 06-11 requires income tax benefits from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity classified awards and outstanding equity share options to be recognized as an increase in additional paid-in capital and to be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. The adoption of EITF 06-11 did not have a material impact on IDACORP's or IPC's consolidated financial statements.

New Accounting Pronouncements

See Note 1 to IDACORP's and IPC's Condensed Consolidated Financial Statements for a discussion of recently issued 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, 2008.

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, 2008, IDACORP and IPC had \$389 million and \$321 million, respectively, in floating rate debt, net of temporary investments. Assuming no change in either company's financial structure, if variable interest rates were to average one percentage point higher than the average rate on September 30, 2008, interest expense for the year ending December 31, 2008, would increase and pre-tax earnings would decrease by approximately \$3.9 million for IDACORP and \$3.2 million for IPC.

IDACORP's and IPC's floating rate debt includes a \$170 million term loan credit agreement used to effect a mandatory purchase of \$166.1 million of IPC's pollution control bonds. Additional information concerning both the term loan credit agreement and the pollution control bonds can be found in MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - LIQUIDITY AND CAPITAL

RESOURCES - Financing Programs.

Fixed Rate Debt: As of September 30, 2008, IDACORP and IPC had outstanding fixed rate debt of \$1,094 million and \$1,075 million, respectively. The fair market value of this debt was \$1,007 million and \$987 million, respectively. These instruments are fixed rate, and therefore do not expose IDACORP or IPC to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately \$93 million for IDACORP and \$92 million for IPC if interest rates were to decline by one percentage point from their September 30, 2008 levels.

Commodity Price Risk

Utility: 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, 2007. In a limited manner, IPC also 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 under SFAS 133 and are therefore 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.

Credit Risk

Utility: IPC's credit risk has not changed materially from that reported in the Annual Report on Form 10-K for the year ended December 31, 2007.

Table of Contents

Equity Price Risk

IDACORP and IPC are exposed to price fluctuations in equity markets, in part through their pension plan assets. As a result of recent market declines, the fair value of the plans' assets has decreased. If these declines do not reverse by December 31, 2008, they will result in increased future amounts required to be contributed to the plans. Additional information concerning pension funding requirement can be found in MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - LIQUIDITY AND CAPITAL RESOURCES - Contractual Obligations.

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, 2008, 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, 2008, 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, 2008, 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

Reference is made to Note 6 to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

ITEM 1A. RISK FACTORS

Volatility and decreased lending capacity in the financial markets may negatively affect IDACORP, Inc. s and Idaho Power Company s ability to access capital and/or increase their cost of borrowing. IDACORP, Inc. and Idaho Power Company require liquidity to pay operating expenses and principal of and interest on debt and to finance capital expenditures. Financial markets have recently experienced extreme volatility and disruption causing the cost of borrowing to rise and the availability of liquidity and credit for borrowers to decrease; actions taken by the United States Government, the Federal Reserve and other governmental and regulatory bodies may be insufficient to stabilize these markets. As a result, IDACORP, Inc. and Idaho Power Company may experience higher interest costs and/or be unable to access capital, including the commercial paper markets. These conditions may adversely affect IDACORP, Inc. s and Idaho Power Company s results of operations, financial condition and cash flows.

IDACORP and Idaho Power Company may incur losses on their investments or be unable to sell their investments when they desire to do so, which could adversely affect their liquidity and financial condition. IDACORP and Idaho Power Company invest cash in short-term interest bearing accounts, including money market funds. Volatility in the financial markets has resulted in a lack of liquidity and declines in value of some money market funds. If the financial markets do not stabilize, the companies may realize losses on some or all of their invested funds or be unable to sell their investments when they desire to do so. This could adversely affect IDACORP s and Idaho Power Company s liquidity and financial condition.

Table of Contents

National and regional economic conditions may cause increased late payments and uncollectible accounts, which would reduce earnings and cash flows. Recent concerns over inflation, energy costs, the availability and cost of credit, declining business and increased unemployment have contributed to an economic slowdown and fears of recession. These factors have resulted, and may continue to result, in an increase in late payments and uncollectible accounts and reduce IDACORP Inc.'s and Idaho Power Company's earnings and cash flows.

Adverse financial market conditions may increase Idaho Power Company's pension plan costs and reduce cash flows. Idaho Power Company's required contributions to pension plans and the reported costs of providing pension and other postretirement benefits are affected by fair value of plan assets, assumed rates of return on plan assets, changes in interest rates used to measure minimum funding levels under the plans and governmental regulations. As conditions within the financial markets have deteriorated, the fair value of the plans' assets has declined. In addition, the Pension Protection Act of 2006, which became effective in 2008, alters the manner in which pension plan assets and liabilities are valued for purposes of calculating required contributions and changes the timing of required contributions to underfunded plans. These changes may result in increased volatility in the amount and timing of Idaho Power Company's future contributions to the plans. Any increases in cash funding obligations may reduce Idaho Power Company's cash flows.

Federal regulation of greenhouse gas emissions from power plants could reduce Idaho Power Company's ability to meet the electricity needs of its customers and adversely affect IDACORP Inc.'s and Idaho Power Company's results of operations, financial condition and cash flows. Debate continues in Congress and within the United States Environmental Protection Agency on the direction and scope of a federal program to regulate greenhouse gas emissions. There is, however, a growing consensus that a federal program to reduce greenhouse gas emissions will be adopted. In July 2008, the Environmental Protection Agency issued an advanced notice of proposed rulemaking requesting comments on a wide variety of issues regarding the regulation of carbon dioxide, the most common greenhouse gas, under the federal Clean Air Act. A change of administration in January 2009 also is widely expected to spur the development of new federal proposals in Congress and the Environmental Protection Agency that could lead to the adoption of a mandatory federal program to reduce greenhouse gas emissions through, for example, an economy-wide cap-and-trade program or a carbon tax. A federal program to reduce greenhouse gas emissions could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because new technologies for reducing carbon dioxide emissions from coal, including carbon capture and storage, are not yet proven. A federal program to reduce greenhouse gas emissions which fails to include flexible compliance measures could make it uneconomical to continue to use coal for the generation of electricity, reduce Idaho Power Company's ability to meet the electricity needs of its customers and adversely affect IDACORP Inc.'s and Idaho Power Company's results of operations, financial condition and cash flows.

These additional Risk Factors should be read in conjunction with the Risk Factors included in IDACORP's and IPC's Annual Report on Form 10-K for the year ended December 31, 2007.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS**Restrictions on Dividends:**

Covenants under IDACORP's credit facility, IPC's credit facility and IPC's term loan credit agreement require IDACORP and IPC to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization of no more than 65 percent at the end of each fiscal quarter. 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 make 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 cause their leverage ratios to exceed 65 percent or violate IPC's Code of Conduct. At September 30, 2008, the leverage ratios for IDACORP and IPC were 54 percent and 55 percent, respectively and IPC's common equity capital was 45 percent of its total adjusted capital. As a result of the credit facility covenants, IDACORP and IPC had \$471 million and \$405 million, respectively, available to dividend at September 30, 2008.

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.

Issuer Purchases of Equity Securities:**IDACORP, Inc. Common Stock**

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(d) Maximum Number	
			(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
July 1 - July 31, 2008	-	\$ -	-	-
August 1 - August 31, 2008	-	-	-	-
	976	29.25	-	-

September 1 September 30,
2008

Total	976	\$	29.25	-	-
-------	-----	----	-------	---	---

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

Table of Contents

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

Edgar Filing: IDACORP INC - Form 10-Q

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 5/10/05, as Exhibit 4, Fortieth, May 1, 2005.
File number 1-3198, Form 8-K filed 10/10/06, as Exhibit 4, Forty-first, October 1, 2006.
File number 1-3198, Form 8-K filed 6/4/07, as Exhibit 4, Forty-second, May 1, 2007.
File number 1-3198, Form 8-K filed 9/26/07, as Exhibit 4, Forty-third, September 1, 2007.

Edgar Filing: IDACORP INC - Form 10-Q

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

Edgar Filing: IDACORP INC - Form 10-Q

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).
- *10.151 Idaho Power Company Security Plan for Senior Management Employees I - a non-qualified, deferred compensation plan, amended

Edgar Filing: IDACORP INC - Form 10-Q

and restated effective December 31, 2004, and as further amended March 14, 2007. File number 1-14465, 1-3198, Form 10-K for the year-ended December 31, 2007, filed on February 28, 2008, as Exhibit 10.15.

- *10.161 Idaho Power Company Security Plan for Senior Management Employees II, a non-qualified, deferred compensation plan, effective January 1, 2005, 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)(xxxv).
- *10.171 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).
- *10.181 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).
- *10.191 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 November 2, 2006, as Exhibit 10(h)(vii).
- *10.201 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).
- *10.211 IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended and restated on November 15, 2007. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on February 28, 2008, as Exhibit 10.21.
- *10.221 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).
- *10.231 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).
- *10.241 Form of Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (senior vice president and higher), as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q

Edgar Filing: IDACORP INC - Form 10-Q

for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(x).

- *10.251 Form of Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and IPC (below senior vice president), 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)(xi).
- *10.261 IDACORP, Inc. 2000 Long-Term Incentive and Compensation 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)(xii).
- *10.271 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).
- *10.281 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).
- *10.291 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).
- *10.301 IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (March 20, 2008). File number 1-14465, 1-3198, Form 8-K, filed on 3/26/08, as Exhibit 10.1.
- *10.311 IDACORP, Inc. Executive Incentive Plan. File Number 1-14465, 1-3198, Form 8-K/A, filed on 2/27/08, as Exhibit 10.1.
- *10.321 Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, 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)(xxxvi).
- *10.331 IDACORP, Inc. and IPC 2008 Compensation for Non-Employee Directors of the Board of Directors. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on February 28, 2008, 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

Edgar Filing: IDACORP INC - Form 10-Q

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 April 1, 2008, among Idaho Power Company and JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America,

Edgar Filing: IDACORP INC - Form 10-Q

N.A., Union Bank of California, N.A. and Wachovia Bank, National Association, as lenders. File number 1-14465, 1-3198, Form 10-Q for the quarter ended March 31, 2008, filed on 5/8/08, 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.
- *10.441 IDACORP, Inc. Executive Incentive Plan NEO 2008 Award Opportunity Chart. File number 1-14465, 1-3198, Form 8-K/A, filed on 2/27/08, as Exhibit 10.2.
- *10.451 IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan Performance Share Award Agreement (performance with two goals) NEO 2008 Award Opportunity Chart. File number 1-14465, 1-3198, Form 8-K, filed on 3/26/08, as Exhibit 10.2.
- *10.46 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.
- 10.47 Electric Service Agreement, dated September 17, 2008, between IPC and Hoku Materials, Inc.
- 10.481 Form of Deferred Compensation Agreement between IDACORP, Inc. or Idaho Power Company and Directors of IDACORP, Inc. and Idaho Power Company.
- 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 Combined Fixed Charges and Preferred Dividend Requirements. (IDACORP, Inc.)
- 12.4 Statement Re: Computation of Supplemental Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements. (IDACORP, Inc.)
- 12.5 Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)
- 12.6 Statement Re: Computation of Supplemental Ratio of Earnings to Fixed Charges. (IPC)
- 15 Letter Re: Unaudited Interim Financial Information.
- *21

Edgar Filing: IDACORP INC - Form 10-Q

Subsidiaries of IDACORP, Inc. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on February 28, 2008, 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 third quarter 2008.

1 Management contract or compensatory plan or arrangement

72-78

Table of Contents

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 November 6, 2008

By: /s/ J. LaMont Keen
J. LaMont Keen
President and Chief Executive Officer

Date November 6, 2008

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

IDAHO POWER COMPANY
(Registrant)

Date November 6, 2008

By: /s/ J. LaMont Keen
J. LaMont Keen
President and Chief Executive Officer

Date November 6, 2008

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

Table of Contents

EXHIBIT INDEX

Exhibit Number

10.47	Electric Service Agreement, dated September 17, 2008, between IPC and Hoku Materials, Inc.
10.481	Form of Deferred Compensation Agreement between IDACORP, Inc. or Idaho Power Company and Directors of IDACORP, Inc. and Idaho Power Company.
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 Combined Fixed Charges and Preferred Dividend Requirements. (IDACORP, Inc.)
12.4	Statement Re: Computation of Supplemental Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements. (IDACORP, Inc.)
12.5	Statement Re: Computation of Ratio of Earnings to Fixed Charges. (IPC)
12.6	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) certification.
31.2	IDACORP, Inc. Rule 13a-14(a) certification.

Edgar Filing: IDACORP INC - Form 10-Q

31.3	IPC Rule 13a-14(a) certification.
31.4	IPC Rule 13a-14(a) certification.
32.1	IDACORP, Inc. Section 1350 certification.
32.2	IDACORP, Inc. Section 1350 certification.
32.3	IPC Section 1350 certification.
32.4	IPC Section 1350 certification.
99	Earnings press release for third quarter 2008.

1 Management contract or compensatory plan or arrangement

80
