Management's Discussion and Analysis – 3rd Quarter

Net Revenues

Through the nine months ended June 30, 2001, BPA incurred net expenses of $95 million, compared with $243 million net revenues for the same period a year ago. The primary factor causing the decrease of $338 million, was increased purchased power partially offset by the treatment of "bookouts" under Financial Accounting Standards Board Statement of Financial Accounting Standards No. 133. "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133).

Operating Revenues

Operating revenues of $3.2 billion from the sales of electricity and transmission were up $1.1 billion compared to the same period of fiscal 2000. This represents an increase of 54 percent. Revenues were up because market prices for discretionary power sales increased to an average of 86 mills from the previous year average of 26 mills.

Mark–to–market losses on derivative instruments were $168 million at the transition on Oct. 1, 2000. Mark–to–market gains were $269 million during the first three-quarters of fiscal 2001. Bookouts are common in the electric utility industry as a power scheduling convenience when two utilities happen to have offsetting transactions for the same delivery period – a sale and a purchase – at the same delivery location. SFAS 138 amends certain sections of SFAS 133 and specifically defines instruments subject to bookout as not qualifying for the normal purchase and normal sales exemption contained in SFAS 133. As a result, the instruments subject to bookout are accounted for using mark-to-market accounting through the income statement. While authoritative accounting guidance in this area continued to emerge during the first three quarters of this fiscal year, BPA management elected to apply the most current guidance available related to SFAS 133 and SFAS 138. During the three months ended June 30, 2001 Bonneville recalculated its mark-to-market position and adjusted its mark-to-market gain for the nine months ended June 30, 2001. The gain of $269 million for the nine months ended June 30, 2001 incorporates the adjusted mark-to-market calculation.

Miscellaneous revenues increased from $36 million to $70 million due to increased energy service business revenues, offsetting revenues from aluminum hedging activities, and some miscellaneous power sales.

U.S. Treasury credits soared from $63 million to $210 million. The federal dams are multi-purpose facilities, including generation of power, irrigation, recreation, transportation, and flood control. The Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Regional Act) directs BPA to pay for fish and wildlife costs on behalf of the entire hydro system. In other parts of the country taxpayers pay for such programs directly through appropriations, whereas in the northwest a sizable portion of taxpayers' obligation for fish recovery is funded directly by BPA. Section 4(h)(10)(C) of the Regional Act implements the requirement that power ratepayers pay only the power share of costs. Poor hydro conditions and high market prices drove purchased power costs up, meaning the cost of biological opinion and program implementation were higher. Consequently 4(h)(10)(C) fish credits also increased significantly.

Operating Expenses

Operations and maintenance costs through the third quarter of fiscal 2001 were down $3 million from the previous year.

BPA's cost for short-term purchased power was $1.6 billion or eight times higher than the prior year. During the first three-quarters of fiscal 2001, BPA spent about 2.5 times more than the amount paid for purchased power in the entire fiscal year ended Sept. 30, 2000. Federal generation declined by 24 million megawatt-hours or 35 percent from the same period in the prior year, due to low streamflows. The forecast January through July volume runoff is the second lowest since 1928. The average cost of power purchased increased from about $34 per megawatt-hour during the first 9 months of fiscal 2000 to about $93 per megawatt-hour for the corresponding period in fiscal 2001. The combination of higher market prices and reduced hydro generation is the cause of the increased purchased power expense.

In total, operating expenses through June 30th increased $1.3 billion or 80 percent over the comparable period a year earlier.

Interest Expense

Net interest expense decreased $6 million, or 2 percent, compared to the same period in 2000. Interest income earned on BPA's cash account with the U.S. Treasury is netted against interest expense. As BPA's cash balance has increased over the past year, interest income has increased and is reflected in the decreased net interest expense.

Forecast Financial Condition

The current forecast for fiscal 2001 year-end financial reserves – cash and deferred borrowing authority – is that year-end reserves will be $400 to $800 million, compared to $811 million, at Sept. 30, 2000.

Looking Forward

BPA had entered into Subscription power sales contracts to serve load, which at Oct. 1, 2001 was approximately 3,700 average megawatts more than the federal system produces on a firm-planning basis. BPA secured about 1,300 average megawatts of additional power at reasonable prices, mostly prior to market prices rising dramatically last year. That left BPA with the need to buy another 2,400 average megawatts in a volatile and potentially exorbitantly high-priced market. To deal with this increased load that BPA will serve in the coming rate period, BPA has submitted to FERC its Final Supplemental Proposal for the 2002 to 2006 rate period, which begins Oct. 1.

The Supplemental Proposal includes three Cost Recovery Adjustment Clauses (CRACs) that will collect additional revenues to insure that BPA has sufficient funds to meet its obligations, including repayment to Treasury during the upcoming rate period. The three CRACs include a Load-Based (LB) CRAC, a Financial Based (FB) CRAC, and a Safety Net (SN) CRAC. The LB CRAC is a percentage adjustment to the base May rates and is based on BPA's costs to purchase power to meet load obligations. Because BPA will be acquiring this additional power in a highly volatile market, it is not possible to accurately forecast the cost of purchasing this power over the entire five-year rate period. Accordingly, the LB CRAC has been designed to be responsive to changes in the market price of power and will be calculated every six months to recover the anticipated augmentation costs to meet load that cannot be recovered with the base rates.

BPA engaged in a significant load reduction effort that resulted in lower rates than would otherwise have been necessary to recover the costs of high-priced power purchases. In response to BPA's request to reduce demand for power, the region committed to reduce loads by 2,277 average megawatts for the first six months of our five-year rate period, starting Oct.1. The first LB CRAC of 46% was set in June 2001 for the period October 2001 through March 2002.

The FB CRAC triggers when a forecast of Accumulated Net Revenues falls below a threshold value for a particular year. The SN CRAC is designed to raise rates if a payment to Treasury or other creditor has been missed, or there is a 50 percent probability that such a payment may be missed in the then-current year. BPA believes it is unlikely that the FB CRAC will be triggered in fiscal 2002.

Federal Columbia River Power System

Comparative Balance Sheets (Unaudited)
(Thousands of Dollars)

	June 30	
	2001	2000
ASSETS		
UTILITY PLANT:		
Completed plant	**$11,122,061**	$11,077,310
Accumulated depreciation	**(3,762,053)**	(3,647,261)
	7,360,008	7,430,049
Construction work in progress	**754,977**	613,267
Net utility plant	**8,114,985**	8,043,316
NON-FEDERAL PROJECTS	**6,434,014**	6,688,337
TROJAN DECOMMISSIONING COST	**72,258**	82,240
CONSERVATION, net of accumulated amortization	**459,104**	522,563
FISH AND WILDLIFE, net of accumulated amortizatio	**136,474**	143,886
CURRENT ASSETS	**1,515,819**	1,415,085
OTHER ASSETS	**462,912**	193,735
	$17,195,566	$17,089,162
CAPITALIZATION AND LIABILITIES		
ACCUMULATED NET REVENUES (EXPENSES)	**$38,142**	$134,617
FEDERAL APPROPRIATIONS	**4,530,523**	4,513,243
CAPITALIZATION ADJUSTMENT	**2,276,952**	2,345,408
LONG-TERM DEBT	**2,723,200**	2,355,900
NON-FEDERAL PROJECTS DEBT	**6,077,970**	6,376,903
TROJAN DECOMMISSIONING RESERVE	**59,658**	59,640
CURRENT LIABILITIES	**933,083**	840,659
DEFERRED CREDITS	**556,038**	462,792
	$17,195,566	$17,089,162

Comparative Statements of Revenues and Expenses (Unaudited)
(Thousands of Dollars)

	Nine months ended June 30		Twelve months ended June 30	
	2001	2000	**2001**	2000
Operating Revenues:				
Revenues	**$2,962,846**	$2,104,908	**$3,898,107**	$2,818,839
SFAS 133 mark-to-market gain	**268,585**	0	**268,585**	0
Operating Revenues	**3,231,431**	2,104,908	**4,166,692**	2,818,839
Operating Expenses:				
Operations and maintenance	**670,903**	673,784	**919,462**	933,527
Purchased power	**1,566,490**	195,586	**1,995,786**	288,027
Tenaska	**0**	0	**(26,817)**	0
Non-Federal projects	**383,419**	462,021	**481,997**	621,887
Residential exchange	**51,018**	47,514	**67,097**	63,524
Federal projects depreciation	**239,071**	230,384	**328,629**	324,407
Operating Expenses	**2,910,901**	1,609,289	**3,766,154**	2,231,372
Net operating revenues	**320,530**	495,619	**400,538**	587,467
Interest Expense	**246,645**	252,773	**328,522**	333,193
Net Income from Continuing Operations	**$73,885**	$242,846	**$72,016**	$254,274
Cumulative Effect of SFAS 133	**(168,491)**	0	**(168,491)**	0
NET REVENUES (EXPENSES)	**($94,606)**	$242,846	**($96,475)**	$254,274

Derivative Instruments and Hedging Activities

On the date of adoption (Oct. 1, 2000), BPA recorded a $168 million loss primarily attributable to the requirement to account for bookout transactions under SFAS 133. Going forward from the date of adoption, BPA estimates the impact of SFAS 133 to be immaterial on a long-term basis, as the effects of marking derivatives, including bookout transactions, to market will reverse and eliminate over the terms of the related contracts. However, SFAS 133 is expected to have significant effect in increasing volatility of earnings (losses) on a period to period basis. While authoritative accounting guidance in this area continued to emerge during the first 3 quarters of this fiscal year, BPA management elected to apply the most current guidance available related to SFAS 133 and SFAS 138. During the three months ended June 30, 2001 Bonneville recalculated its mark-to-market position and adjusted its mark-to-market gain for the nine months ended June 30, 2001. The above gain of $269 million for the nine months ended June 30, 2001 incorporates the adjusted mark-to-market calculation.

Operating Segments

The FCRP's major operating segments are defined by the utility functions of generation and transmission. The Power Business Line identifies the operations of the generation function, while the Transmission Business Line identifies the operations of the transmission function.

The business lines are not separate legal entities. Where applicable, "Corporate" represents items that are necessary to reconcile to the financial statements which generally include shared activity and eliminations. Each FCRPS segment operates predominantly in one industry and geographic region: the generation and transmission of electric power in the Pacific Northwest.

The FCRPS centrally manages all interest expense activity. Since the Bonneville Power Administration has one fund with the United States Department of Treasury, all cash and cash transactions are also centrally managed. Unaffiliated revenues represent sales to external customers for each segment. Intersegment revenues are eliminated as shown.

FCRPS management evaluates the performance of the business lines based on Net Operating Margin (NOM) and does not track the separate balance sheets or net revenues on a business line level. NOM represents revenues generated from operations less operating and maintenance expenses of the segment's revenue generating assets.

Major Customers

During fiscal 2001, and 2000, no single customer represented 10% or more of the FCRPS's revenues.

SFAS 131 SEGMENT REPORTING

(Thousands of Dollars)

Nine months ended June 30

2001	**Power**	**Transmission**	**Corporate**	**Total**
Unaffiliated Revenues	**$2,891,802**	**$339,629**	**$0**	**$3,231,431**
Intersegment Revenues	**45,313**	**142,303**	**(187,616)**	**-**
Operating Revenues	**$2,937,115**	**$481,932**	**($187,616)**	**$3,231,431**
Net Operating Margin	**$343,379**	**$285,178**	**($98,902)**	**$529,655**

2000	Power	Transmission	Corporate	Total
Unaffiliated Revenues	$1,841,813	$263,095	$0	$2,104,908
Intersegment Revenues	35,095	161,539	(196,634)	-
Operating Revenues	$1,876,908	$424,634	($196,634)	$2,104,908
Net Operating Margin	$1,049,844	$238,941	($53,247)	$1,235,538

Twelve Months Ended June 30

2001	**Power**	**Transmission**	**Corporate**	**Total**
Unaffiliated Revenues	**$3,724,545**	**$442,147**	**$0**	**$4,166,692**
Intersegment Revenues	**56,603**	**193,491**	**(250,094)**	**-**
Operating Revenues	**$3,781,148**	**$635,638**	**($250,094)**	**$4,166,692**
Net Operating Margin	**$601,515**	**$354,425**	**($179,199)**	**$776,741**

2000	Power	Transmission	Corporate	Total
Unaffiliated Revenues	$2,485,090	$333,749	$0	$2,818,839
Intersegment Revenues	51,176	218,747	(269,923)	-
Operating Revenues	$2,536,266	$552,496	($269,923)	$2,818,839
Net Operating Margin	$1,446,630	$295,533	($144,878)	$1,597,285