DOE/CF-029
Volume 6

Department of Energy

FY 2009 Congressional Budget Request

Power Marketing Administrations

Southeastern Power Administration
Southwestern Power Administration
Western Area Power Administration
Bonneville Power Administration

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Volume 6

Table of Contents

The Department of Energy's Congressional Budget justification is available on the Office of Chief Financial Officer, Office of Budget homepage at http://www.cfo.doe.gov/crorg/cf30.htm.

Department of Energy
Appropriation Account Summary

(dollars in thousands - OMB Scoring)

	FY 2007 Current Op. Plan	FY 2008 Current Approp.	FY 2009 Congressional Request	FY 2009 vs. FY 2008 $	FY 2009 vs. FY 2008 %
Discretionary Summary By Appropriation					
Energy And Water Development, And Related Agencies					
Appropriation Summary:					
Energy Programs					
Energy efficiency and renewable energy	——	1,722,407	1,255,393	-467,014	-27.1%
Electricity delivery and energy reliability	——	138,556	134,000	-4,556	-3.3%
Nuclear energy	——	961,665	853,644	-108,021	-11.2%
Legacy management	——	33,872	——	-33,872	-100.0%
Energy supply and Conservation	2,145,149	——	——	——	——
Fossil energy programs					
Clean coal technology	——	-58,000	——	+58,000	+100.0%
Fossil energy research and development	580,946	742,838	754,030	+11,192	+1.5%
Naval petroleum and oil shale reserves	21,316	20,272	19,099	-1,173	-5.8%
Strategic petroleum reserve	164,441	186,757	344,000	+157,243	+84.2%
Northeast home heating oil reserve	7,966	12,335	9,800	-2,535	-20.6%
Total, Fossil energy programs	774,669	904,202	1,126,929	+222,727	+24.6%
Uranium enrichment D&D fund	556,606	622,162	480,333	-141,829	-22.8%
Energy information administration	90,653	95,460	110,595	+15,135	+15.9%
Non-Defense environmental cleanup	349,687	182,263	213,411	+31,148	+17.1%
Science	3,836,613	3,973,142	4,721,969	+748,827	+18.8%
Nuclear waste disposal	99,206	187,269	247,371	+60,102	+32.1%
Departmental administration	147,943	148,415	154,827	+6,412	+4.3%
Inspector general	41,819	46,057	51,927	+5,870	+12.7%
Innovative technology loan guarantee program	——	4,459	——	-4,459	-100.0%
Total, Energy Programs	8,042,345	9,019,929	9,350,399	+330,470	+3.7%
Atomic Energy Defense Activities					
National nuclear security administration:					
Weapons activities	6,258,583	6,297,466	6,618,079	+320,613	+5.1%
Defense nuclear nonproliferation	1,824,202	1,335,996	1,247,048	-88,948	-6.7%
Naval reactors	781,800	774,686	828,054	+53,368	+6.9%
Office of the administrator	358,291	402,137	404,081	+1,944	+0.5%
Total, National nuclear security administration	9,222,876	8,810,285	9,097,262	+286,977	+3.3%
Environmental and other defense activities:					
Defense environmental cleanup	5,731,240	5,349,325	5,297,256	-52,069	-1.0%
Other defense activities	636,271	754,359	1,313,461	+559,102	+74.1%
Defense nuclear waste disposal	346,500	199,171	247,371	+48,200	+24.2%
Total, Environmental & other defense activities	6,714,011	6,302,855	6,858,088	+555,233	+8.8%
Total, Atomic Energy Defense Activities	15,936,887	15,113,140	15,955,350	+842,210	+5.6%
Power marketing administrations:					
Southeastern power administration	5,602	6,404	7,420	+1,016	+15.9%
Southwestern power administration	29,998	30,165	28,414	-1,751	-5.8%
Western area power administration	232,326	228,907	193,346	-35,561	-15.5%
Falcon & Amistad operating & maintenance fund	2,665	2,477	2,959	+482	+19.5%
Colorado River Basins	——	-23,000	-23,000	——	——
Total, Power marketing administrations	270,591	244,953	209,139	-35,814	-14.6%
Federal energy regulatory commission	——	——	——	——	——
Subtotal, Energy And Water Development and Related Agencies	24,249,823	24,378,022	25,514,888	+1,136,866	+4.7%
Uranium enrichment D&D fund discretionary payments	-452,000	-458,787	-463,000	-4,213	-0.9%
Excess fees and recoveries, FERC	-43,595	-34,411	-36,932	-2,521	-7.3%
Total, Discretionary Funding	**23,754,228**	**23,884,824**	**25,014,956**	**+1,130,132**	**+4.7%**

Southeastern Power Administration

Southeastern Power Administration

Southeastern Power Administration

Proposed Appropriation Language

For necessary expenses of operation and maintenance of power transmission facilities and of marketing electric power and energy, including transmission wheeling and ancillary services, pursuant to section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), as applied to the southeastern power area, $[6,463,000] *7,420,000* to remain available until expended: Provided, that [notwithstanding the provisions of 31 U.S.C. 3302, beginning in fiscal year 2008 and thereafter, such funds as are received by the Southeastern Power Administration from any State, municipality, corporation, association, firm, district, or individual as advance payment for work that is associated with Southeastern's Operation and Maintenance, consistent with that authorized in section 5 of the Flood Control Act of 1944, shall be credited to this account and be available until expended. Provided further, That,] notwithstanding 31 U.S.C. 3302, up to $[48,413,000] *49,520,000* collected by the Southeastern Power Administration pursuant to the Flood Control Act of 1944 to recover purchase power and wheeling expenses shall be credited to this account as offsetting collections, to remain available until expended for the sole purpose of making purchase power and wheeling expenditures.

Explanation of Change

Authority to fund from other sources as advanced payments for work associated with Operation and Maintenance was authorized with the passage of the FY 2008 Congressional Budget and is deleted from the FY 2009 Congressional Budget Appropriation Language.

Southeastern Power Administration

Overview

Appropriation Summary by Program

(dollars in thousands)

	FY 2007 Current Appropriation	FY 2008 Original Appropriation	FY 2008 Adjustments	FY 2008 Current Appropriation	FY 2009 Request
Southeastern Power Administration					
Program Direction (PD)	5,602	6,463	-59	6,404	7,420
Purchase Power and Wheeling (PPW)	47,198	62,215	0	62,215	63,522
Subtotal, Southeastern Program Level	52,800	68,678	0	68,619	70,942
Offsetting collections PPW	-32,713	-48,413	0	-48,413	-49,520
Alternative financing PPW	-14,485	-13,802	0	-13,802	-14,002
Total, Southeastern Power Administration	5,602	6,463	-59	6,404	7,420

Preface

As the Nation moves forward to strengthen its national and economic security, the Department of Energy (DOE or the Department) leads a critical effort promoting a diverse supply and delivery of reliable, affordable, and environmentally sound energy. Southeastern Power Administration (Southeastern or SEPA) supports this effort by marketing and delivering hydroelectric power in the southeast. Southeastern's FY 2009 budget supports DOE's Strategic Theme 1, Energy Security by implementing Goal 1.3, Energy Infrastructure. Southeastern implements Goal 1.3 by promoting energy efficiency improvements and renewable resources among its customers, and scheduling power deliveries in compliance with standards established by the Federal Energy Regulatory Commission's (FERC) Electric Reliability Organization (ERO).

Within the Southeastern appropriation, there is one program: Operation and Maintenance, which includes two subprograms: Program Direction and Purchase Power and Wheeling. Program Direction supports day-to-day agency operation and Purchase Power and Wheeling supports acquisition of contractually-required transmission services and power purchases.

Mission

The mission of Southeastern is to market and deliver Federal hydroelectric power at the lowest possible cost consistent with sound business principles to public bodies and cooperative utilities in the southeastern United States in a professional, innovative, customer-oriented manner, while continuing to meet the challenges of an ever-changing electric utility environment through continuous improvements.

Benefits

Southeastern supports the Department's Energy Security Goal by promoting energy efficiency and renewable energy and managing the dispatch and distribution of Federal hydroelectric power resources in the southeastern United States in a safe, affordable, and environmentally sound manner, while meeting national utility performance standards and balancing the diverse interests of other water resource users. This budget submission ensures effective management of Federal hydroelectric power resources and provides for: a diverse supply of generating resources that enhance regional power system reliability; power revenues that repay taxpayers' investment in the Federal power system; and regional economic benefits from delivery of Federal power to rural electric cooperatives, municipal utilities, and other public entities. Southeastern has implemented rates that repay emergency power purchases within the fiscal year that they are incurred and is on track to repay the Federal investment in hydroelectric resources within required time periods.

This budget submission enables Southeastern to support the Energy Security Goal by promoting strategies that enhance energy efficiency and renewable energy technologies. Effective management of hydroelectric resources, combined with promotion of energy efficiency and renewable technologies, contributes to the long-term solution of economic and environmental challenges associated with electricity demand.

Southeastern contributes program benefits in support of Climate Change activities by reducing carbon emissions through generation of hydroelectric power which has zero carbon emissions. Southeastern's stream-flow generation of 4,555 GWH in FY 2007 offset fossil fuel resources and reduced overall CO2 emissions by 2.8 million metric tons. Southeastern supports the Climate Change and Technology Program by promoting residential, commercial and industrial energy efficiency as well as development of wind, solar, and biomass technologies when they are economically feasible. Southeastern works closely with DOE's Wind Powering America Program to ensure that customers in areas with category 3 winds or higher have the information necessary to benefit from implementing advanced wind technology.

Strategic Themes and Goals and GPRA Unit Program Goals

The Department's Strategic Plan identifies five Strategic Themes (one each for nuclear, energy, science, management, and environmental aspects of the mission) plus 16 Strategic Goals that tie to the Strategic Themes. Southeastern Power Administration supports the following goals:

Strategic Theme 1, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

Strategic Goal 1.3, Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

The programs funded within the Southeastern Power Administration appropriation have one GPRA Unit Program Goal that contributes to the Strategic Goals in the "goal cascade." This goal is Market and Deliver Federal Power.

GPRA Unit Program Goal 1.3.23.00: Market and Deliver Federal Power: Customers receive the benefits of Federal power that produce adequate revenue to repay the American taxpayers' investments allocated to power.

Contribution to Strategic Goal

Southeastern contributes to the Energy Security Goal by performing its power marketing mission through two subprogram activities: Program Direction and Purchase Power and Wheeling.

Southeastern contributes to Strategic Goal 1.3, Energy Infrastructure by: promoting energy efficiency and marketing and delivering all available hydroelectric power from U.S. Army Corps of Engineers (Corps) dams, while balancing power needs with the diverse interests of other water resource users; and marketing and delivering Federal power in a cost-efficient manner to assure reliability of the power system and maximize the use of Federal assets to repay the investment (principal and interest), while supporting the President's Management Agenda.

Funding by Strategic and GPRA Unit Program Goal

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Strategic Goal 1.3, Energy Infrastructure			
GPRA Unit Program Goal 1.3.23.00, Market and Deliver Federal Power	52,800	68,619	70,942
Use of offsetting collections PPW	-32,713	-48,413	-49,520
Use of alternative financing PPW	-14,485	-13,802	-14,002
Total, Strategic Goal 1.3, Southeastern Power Administration	5,602	6,404	7,420

Annual Performance Results and Targets[a]

FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Results	FY 2008 Targets	FY 2009 Targets
Strategic Goal 1.3, Energy Infrastructure					
GPRA Unit Program Goal 1.3.23.00: Southeastern Power Administration, Operation and Maintenance					
Attained average monthly NERC compliance ratings of 100 or higher for Control Performance Standard (CPS) 1 and a rating of 90 or above for CPS2. Goal Met. (ER9-2) CPS1:174 CPS2: 99	Attained average monthly NERC compliance ratings of 100 or higher for Control Performance Standard (CPS) 1 and a rating of 90 or above for CPS2. Goal Met. (ER9-2) CPS1:208 CPS2: 100	Meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. Goal Met (ER4-51) CPS1:201 CPS2: 100	Meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. Goal Met (GG 1.3.23) CPS1: 186 CPS2: 100	Meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. (GG 1.3.23) CPS1: TBD CPS2: TBD	Meet North American Electric Reliability Council (NERC) Control Performance Standards (CPS) of CPS1>100 and CPS2>90 and meet or exceed industry averages. CPS1 measures a generating system's performance at matching supply to changing demand requirements and supporting desired system frequency in one minute increments. CPS2 measures a generating system's performance at limiting the magnitude of generation and demand imbalances in ten minute increments. (GG 1.3.23) CPS1: CPS2:
Meet planned annual repayment of principal on Federal power investment. Goal met (ER9-1) Actual: $45 million	Meet planned annual repayment of principal on Federal power investment. Goal met (ER9-1) Actual: $51 million	Assure Annual Required Repayment of the Federal Investment. FY 06 required repayment is $1.0 million. Goal Met (ER4-51) Repaid $4.4 million	Assure Annual Required Repayment of the Federal Investment. FY 07 required repayment is $1.0 million. Goal Met. Repaid $2.1 million (GG 1.3.23)	Assure Annual Required Repayment of the Federal Investment. FY 08 required repayment is $22.2 million. (GG 1.3.23)	Repayment of Federal Power Investment Performance: Repay the Federal Investment within the required repayment period. FY 09 required repayment is $0 million. (GG 1.3.23)

[a] Annual effectiveness and efficiency performance targets will not be reported in the Department's annual Performance and Accountability Report (PAR)

Annual Performance Results and Targets, continued

FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Results	FY 2008 Targets	FY 2009 Targets
GPRA Unit Program Goal 1.3.23.00: Southeastern Power Administration, Operation and Maintenance					
Meet required repayment of Federal power investment within the required repayment period. Goal met. (ER9-2) Actual: $45 million	Meet required repayment of Federal power investment within the required repayment period. Goal met. (ER9-2) Actual: $51.6 million	Provide $635 million in economic benefits to the region from the sale of hydroelectric power. Goal not met (ER4-51) . Actual benefits were $453 million.			
Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3, or the latest published Bureau of Labor Statistics' industry rate, whichever is lower. Goal met. (ER9-2) Actual: Zero Accidents	Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3, or the latest published Bureau of Labor Statistics' industry rate, whichever is lower. Goal met. (ER9-2) Actual: Zero Accidents				

Significant Policy or Program Shift

The Administration supports reclassification of receipts from mandatory to discretionary (net zero appropriations) for the annual operating expenses of Southeastern, Southwestern, and Western Area Power Administrations (PMAs). Reclassification of receipts in this manner would allow the PMA programs to benefit from the alignment of PMA receipts with their annual (non-capital) expenditures provided by appropriations. This alignment would foster increased planning certainty for the PMA programs, which would ultimately improve the reliability and operating efficiency of the Federal power system. The Administration will continue to pursue reclassification of receipts through changes to the existing authorizing statute or by other means.

Means and Strategies

Southeastern will use various means and strategies to achieve its GPRA Unit Program goals. However, various external factors may impact the ability to achieve these goals. The program also performs collaborative activities to help meet its goals.

Southeastern will implement the following means:

- Operate the Federal power system effectively and efficiently by providing training and certification to update workforce skills and updating power system operation technologies to maintain required industry standard compliance.
- Assure power rates are adequate to repay the Federal investment by conducting annual power repayment studies.
- Conduct business process reviews to maximize efficiency and eliminate redundancy.
- Provide economic benefits to the region by marketing and delivering all available hydropower.

Southeastern will implement the following strategies:

- Market and deliver power using appropriations, net billing, bill crediting, and offsetting collections.
- Maintain a diverse and knowledgeable workforce by providing employee training, leadership development, retention programs, and recruitment activities.
- Market all available hydropower by working with the Corps, other Federal entities, States, cooperative and municipal utilities to meet the expectations of our customers, while balancing the interest of other water users.
- Maintain the security of the Federal power system, facilities, and information technology (IT) systems.
- Address industry restructuring changes when needed by reclassifying positions as opportunities arise.
- Maximize the capabilities of business systems to improve processes and provide greater efficiency.
- Promote adoption of energy efficiency and renewable energy among Federal power customers.

These strategies will result in a well-maintained Federal power system that is in compliance with ERO operating regulations and an expert workforce to operate the system in the most effective and cost-efficient manner possible.

The following external factors could affect Southeastern's ability to achieve its program goals:

- Achieving and maintaining system reliability can be affected by weather, natural disasters, changes in the North American Electric Reliability Corporation (NERC) operating standards, new load patterns, deregulation of the electricity market, changing electric industry organizational structures, and additions to other transmission systems interconnected to the Federal system.

- Achieving full repayment of the Federal power investment and enhancing economic growth to the region can be affected by weather, power markets, natural disasters, and other external costs and revenue factors.
- Statutory or administrative reallocation of water storage from hydropower to water supply.

In carrying out its mission to market and deliver hydroelectric power, Southeastern performs the following collaborative activities:

- Southeastern coordinates operational activities with NERC, other regional electric reliability councils, the Corps, customers and other stakeholders to provide the most efficient use of Federal assets.

Validation and Verification

To validate and verify program performance, Southeastern conducts internal and external reviews and audits as directed by the Program Assessment Rating Tool. Southeastern's programmatic activities are subject to continuing review by internal and external entities such as Congress, the Government Accountability Office (GAO, formerly General Accounting Office), the Department of Energy, the Department of Energy's Inspector General, FERC, the U.S. Environmental Protection Agency, the Office of Personnel Management, Southeastern, and National and Regional Reliability Corporations. Southeastern's annual financial audit is conducted and prepared by an independent accounting firm.

Southeastern also complies with Cyber Security requirements as directed by the Department of Energy and NERC. Southeastern is audited by DOE and NERC, as well as internal audits and reviews by the other Power Marketing Administrations and independent auditors every three years for recertification. Compliance with the NERC standards is filed each year through regional reliability organizations. The Department of Energy also requires Southeastern to follow the National Institute of Standards (NIST) and the Federal Information Processing Standards (FIPS).

Program Assessment Rating Tool (PART)

The Department implemented a tool to evaluate selected programs. PART was developed by the Office of Management and Budget (OMB) to provide a standardized way to assess the effectiveness of the Federal Government's portfolio of programs. The structured framework of the PART provides a means through which programs can assess their activities differently than through traditional reviews.

The current focus is to establish outcome-and output-oriented goals, the successful completion of which will lead to benefits to the public, such as increased national security and energy security, and improved environmental conditions. DOE has incorporated feedback from OMB into the FY 2009 Budget Request, and the Department will take the necessary steps to continue to improve performance.

During the FY 2004 budget cycle, Southeastern participated in a program assessment with OMB using the PART. The resulting scores and findings were provided to Congress with the FY 2004 budget request. In the PART review, OMB rated Southeastern "Moderately Effective" with relatively high scores in Planning (72%), Management (86%), and Accountability (73%). In Program Purpose and Design, Southeastern received 60 % due to perceived duplication of power generation resources. Southeastern's power marketing functions conform to requirements of the Flood Control Act of 1944 and other mandates and statutory requirements. To address OMB's concerns, a change in the legislation would be required. Annual Financial Audit and rate reviews by FERC verify that Southeastern is meeting its financial obligations; however, various past GAO reports identified some areas that may be improved under existing authorizations. Southeastern and other Power Marketing Administrations (PMAs) have addressed most of these concerns to the satisfaction of OMB and implemented modifications to improve OMB's ratings. Southeastern continues to work with OMB to improve performance goals and targets.

Southeastern Power Administration

Funding by Site by Program

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Total, Southeastern Power Administration	38,315	54,817	56,940

Major Changes or Shifts

Southeastern Power Administration
Purchase Power and Wheeling

- Lake Cumberland, impounded by the Wolf Creek Dam on the Cumberland River, is the largest storage project in the eastern United States. Leakage in an earthen embankment created a significant safety issue that is being repaired. In the interim, the project is being operated as a run-of-river project with minimum storage. This interim operating plan fundamentally alters the operation of the entire Cumberland system and directly impacts a majority of the Cumberland projects and indirectly forces change in the operation of others. Repairs will continue for the next seven years.

Site Description

Southeastern Power Administration

Southeastern is one of four Power Marketing Administrations within the Department of Energy. Southeastern was created in 1950 to market power and energy produced at Corps hydroelectric power projects. Southeastern markets power at wholesale rates to 293 publicly owned utilities, 199 rural electric cooperatives, and one investor-owned utility in the 11 States of Florida, Georgia, South Carolina, North Carolina, Tennessee, Alabama, Mississippi, Virginia, West Virginia, Kentucky, and Illinois. Southeastern is located in Elberton, Georgia, and has no field offices.

Southeastern Power Administration

Funding Profile by Subprogram

	(dollars in thousands)				
	FY 2007 Current Appropriation	FY 2008 Original Appropriation	FY 2008 Adjustments	FY 2008 Current Appropriation	FY 2009 Request
Southeastern Power Administration					
Program Direction (PD)	5,602	6,463	-59	6,404	7,420
Purchase Power and Wheeling (PPW)[a]	47,198	62,215	0	62,215	63,522
Subtotal, Southeastern Program Level	52,800	68,678	0	68,619	70,942
Offsetting collections PPW	-32,713	-48,413	0	-48,413	-49,520
Alternative financing PPW	-14,485	-13,802	0	-13,802	-14,002
Total, Southeastern Power Administration	5,602	6,463	-59	6,404	7,420

Public Law 78-534, Flood Control Act of 1944
Public Law 95-91, DOE Organization Act of 1977, Section 302
Public Law 101-1-1, Title III, Continuing Fund (amended 1989)
Public Law 102-486, Energy Policy Act of 1992

Mission

Southeastern's power marketing and wheeling activities fulfill the requirements of Section 5 of the Flood Control Act of 1944 and reflect Southeastern's goals and objectives to market and deliver cost-based power in a safe and reliable manner, and repay the Federal investment with interest, while providing environmental and economic benefits to the region. Southeastern focuses on its PART repayment goal which assures timely repayment of the Federal hydropower investment.

Strategic and GPRA Unit Program Goals

The Department's Strategic Plan identifies five Strategic Themes (one each for nuclear, energy, science, management, and environmental aspects of the mission) plus 16 Strategic Goals that tie to the Strategic Themes. The Southeastern Power Administration supports the following goals:

Strategic Theme 1, Energy Security
Strategic Goal 1.3, Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

[a] The total purchase power and wheeling requirements are $47.2 million, $62.2 million, and $63.5 million for FY 2007, FY 2008, and FY 2009, respectively. The total requirements are financed through receipts and alternative financing methods, which include offsetting collections, offsetting receipts (net billing), and bill crediting. For additional detail on funding, refer to the Funding Schedule in the Purchase Power and Wheeling section.

The Southeastern Power Administration program has one GPRA Unit Program Goal which contributes to Strategic Goal 1.3 in the "goal cascade."

Program Goal 1.3.23.00, Market and Deliver Federal Power: Customers receive the benefits of Federal power that produce adequate revenue to repay the American taxpayers' investments allocated to power.

Contribution to Program Goal 1.3.23.00, Energy Infrastructure

Southeastern contributes to the Energy Infrastructure Goal by performing its power marketing mission through two subprogram activities: Program Direction and Purchase Power and Wheeling. Southeastern contributes to General Goal 4, Energy Security, by marketing and delivering all available hydroelectric power from U.S. Army Corps of Engineers (Corps) dams, while balancing power needs with the diverse interests of other water resource users; and markets and delivers Federal power in a cost- efficient manner to assure reliability of the power system and maximize the use of Federal assets to repay the investment (principal and interest), while supporting the President's Management Agenda.

Purchase Power and Wheeling

Funding Schedule by Activity

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Purchase Power and Wheeling			
Purchase Power	12,895	26,370	28,349
Wheeling	34,303	35,845	35,173
Subtotal, Purchase Power and Wheeling	47,198	62,215	63,522
Alternative Financing			
Net Billing	-14,485	-13,802	-14,002
Subtotal, Purchase Power and Wheeling	32,713	48,413	49,520
Offsetting Collections Realized	-32,713	-48,413	-49,520
Total, Purchase Power and Wheeling Budget Authority	0	0	0

Description

The mission of Purchase Power and Wheeling is to provide funding for acquisition of transmission services, ancillary services for the system, and pumping energy for the Richard B. Russell and Carters Pumped Storage units and support of the Jim Woodruff Project. Purchase power and transmission expenses are based on contracts Southeastern maintains with area transmission providers that agree to deliver specified amounts of Federal power from the hydropower projects to Federal power customers. Southeastern has access to a continuing fund for emergency power purchases. Following recommendations made in the PART review, Southeastern implemented a plan to repay Purchase Power and Wheeling expenditures made through the Continuing Fund within one year.

The FY 2009 request uses customer receipts and net billing to pay for purchase power and wheeling expenses. Southeastern's Federal appropriation allows customers to fund purchase power and wheeling expenses in FY 2009 and subsequent years at no cost to the Federal Treasury. Some customers, acting independently or in partnerships, acquire replacement power and transmission services directly from suppliers. Southeastern will continue to assist its customers by arranging funding for these activities through alternative financing instruments, as needed.

The Purchase Power and Wheeling (PPW) subprogram supports Southeastern's mission to market and deliver reliable, cost-based hydroelectric power and related services. Southeastern's PART Goal to maintain acceptable power system operation for control area performance as measured using NERC CPS 1 & 2 provides assurance that projects within Southeastern's control area operate as reliable and efficient grid resources. PPW enables southeastern to wheel Federal power to preference customers, purchase replacement power, and acquire pumping energy to maximize the efficiency and benefits of Southeastern's hydropower resources. Power and services are marketed at rates designed to provide recovery of expenses and Federal investment, as established by law. The recovery of the Federal investment, or repayment, is a key performance goal for Southeastern. The Department of Energy's Strategic Plan reinforces the importance of domestic, renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past and future energy supply and Southeastern's role as a power resource by supplying hydroelectric power to its customers.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Purchase Power	**12,895**	**26,370**	**28,349**
▪ Pumping: Russell Project	8,000	13,500	15,228
Purchase off-peak energy to pump water into the Richard B. Russell Project for on peak generation			
▪ Pumping: Carters Project	4,000	11,970	12,221
Purchase off-peak energy to pump water into the Carters Project for on peak generation			
▪ Support Jim Woodruff Project	895	900	900
Purchase of energy during periods of adverse water conditions including floods (loss of head) and drought			
Wheeling	**34,303**	**35,845**	**35,173**
▪ Wheeling service charges	29,539	31,081	30,469
Wheeling service charges for delivery of power over non-Federal systems			
▪ Ancillary Services	4,764	4,764	4,704
Payment for ancillary services			
Total, Purchase Power and Wheeling	**47,198**	**62,215**	**63,522**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Purchase Power and Wheeling	
Expected pumping energy costs are the result of increased fuel and fuel transportation expenses incurred by utilities that provide pumping energy. Transmission cost increases also added to higher PPW expenses.	+1,307
Total, Purchase Power and Wheeling	+1,307

Program Direction

Funding Profile by Category

	(dollars in thousands/whole FTEs)		
	FY 2007	FY 2008	FY 2009
Southeastern Power Administration			
Salaries and Benefits	4,051	4,599	4,976
Travel	126	346	467
Support Services	37	41	60
Other Related Expenses	1,388	1,418	1,917
Total, Program Direction	5,602	6,404	7,420
Total, Full Time Equivalents	42	44	44

Mission

Program direction makes available the Federal staffing resources and associated funding necessary to provide overall direction and execution of Southeastern's program. Southeastern coordinates and cooperates with its partners to operate projects in a manner that enhances the value and reliability of hydropower. Priority is given to integrating environmental concerns and determinations into program actions. Emerging energy efficiency technologies are integrated with marketing strategies and programs.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Salaries and Benefits	**4,051**	**4,599**	**4,976**

Funding supports salaries and benefits for 44 Federal employees who market Federal hydropower, promote energy efficiency and renewable energy, and provide administrative support. The salary estimate is derived from the current year budgeted salaries, plus cost-of-living adjustments, promotions, within-grade increases, DOE-cascading performance awards, retirement payouts for unused leave (annual retirements of five FTEs are anticipated over the planning horizon), and overtime. Benefits are calculated as a percentage of prior year actual. The funding provides for negotiation, preparation, execution, and administration of all contracts for the disposition of electric power, and ensures continuity of electric service to customers. Funding also covers operators who coordinate and schedule pumping energy among providers of pumping energy and the projects and account for all transactions relative to pumping operations of the Carters and Richard B. Russell Projects. Personnel perform Balancing Authority services for Hartwell, Russell, and Thurmond Projects. Southeastern coordinates power operations of projects with all parties, making determinations of capacity and energy availability weekly. Efficiency Performance is measured by two Efficiency Performance Indicators that provide Balancing Area compliance ratings. Funding provides for accounts receivable and payable functions for approximately 300 contracts that benefit more than 500 preference customers. Southeastern executes budget, accounting, and financial management activities, prepares repayment analyses of each system to

(dollars in thousands)

	FY 2007	FY 2008	FY 2009

determine rates, and organizes rate forums, as needed. Repayment performance is measured by comparing required to actual repayment of principal on power investment. In support of the Energy Policy Act of 2005 and the Department's Strategic Goal 1.3, Southeastern vigorously promotes energy efficiency and development of renewable energy among its customers. Funding also covers continuing engineering studies, review of project operations, and evaluation of impacts of proposed or actual changes to project operations. Funding also supports IM and Homeland Security initiatives.

Travel	**126**	**346**	**467**

Travel supports transportation and per diem expenses incurred for participation in and development of regional transmission organizations; training expenses for power operator certification; relocation expenses for new FTEs; contract negotiations; preference customer meetings; rate forums; hearings and meetings; Congressional hearings; site visits of existing and new projects; promotion of energy efficiency and renewable energy via Competitive Resource Strategy workshops and meetings; operations meetings with industry self-regulating groups. Self-regulating groups include: SERC Reliability Corporation (SERC), Virginia Carolina Electric Reliability Group (VACAR), Florida Reliability Coordinating Council (FRCC); NERC; the ERO; hydropower task force and project rehabilitation meetings with the Corps, Customer, and SEPA Working Group (C^2SWG); National Environmental Policy Act (NEPA) activities; training; Power Marketing Policy Forums; national and state customer meetings with the National Rural Electric Cooperative Association (NRECA), the American Public Power Association (APPA); Southeastern Federal Power Customers O&M Subcommittee meetings; Interagency Task Force on Finance; Technical Advisory Group meetings; FERC pre-filings and hearings; PJM RTO; and headquarters responsibilities.

Support Services	**37**	**41**	**60**

The Competitive Resource Strategies Program supports preference customer efforts to address energy efficiency issues, and promote development of renewable resources in support of the Department's Strategic Plan Goal 1.3 and the President's National Energy Policy and the Energy Policy Act of 2005. Develop specifications for training programs, prepare program plans, conduct training, and review and evaluate contractors.

Other Related Expenses	**1,388**	**1,418**	**1,917**

Provide administrative support for the office, rent, communications, maintenance, contract services (library services, support for DOE Power Marketing Liaison Office, independent audit of the Southeastern Federal Power Program financial statements), E-GOV, supplies, materials, and equipment and support for cyber and physical security initiatives associated with Homeland Security[a]. Support installation of electronic hardware and software for the operations center and provide maintenance to integrate real-time data from the control area and provide the data to other transmission operators in the Regional Transmission Organization (RTO), and NERC. This equipment supports additional NERC compliance requirements and system reliability. This system is

[a] Southeastern is required to meet the Common Identification Standard for Federal Employees and Contractors, as required by HSPD-12, FIPS Publication 201, Personal Identification Verification for Federal Employees and Contractors, NIST 800-73, Integrated Circuit Card for Personal Identity and Verification for Federal Employees and Contractors, NIST 800-76, Biometric Data Specification for Personal Identity Verification and all other DOE requirements.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
a resource-intensive application that requires maintenance of interconnected fiber optic communication lines for the Supervisory Control and Data Acquisition (SCADA) system. Also reflects expenses associated with infrastructure support: telecommunications equipment; accounting system maintenance; building and computer security equipment; computer hardware and software; and office equipment and financial management system (Oracle). This funding allows the agency to fulfill its obligations under Strategic Theme 1, Energy Security and Goal 1.3, Energy Infrastructure.			
Total, Program Direction	**5,602**	**6,404**	**7,420**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Salaries and Benefits	
Fiscal Year 2009 salaries are derived from budgeted FY 2008 salaries and benefits, plus cost-of-living adjustments, promotions, within-grade increases, DOE-cascading performance awards, retirement payouts for unused leave, and overtime.	+377
Travel	
Derived from PCS expenses and increased travel and training for Operators, IT and security purposes.	+121
Support Services	
Increase in funding for co-sponsored energy efficiency and renewable energy support programs for municipal and cooperative utilities	+19
Other Related Expenses	
▪ Rent increase due to inflation	+8
▪ Audit increase due to incurring additional expense associated with generating agency	+87
▪ Communications expenses associated with upgraded Operations (ops) center communication with projects	+44
▪ Decrease in tuition due to operator and security object class inclusion under travel/training category	-14
▪ Maintenance expenses increased due to financial management and ops center maintenance agreements	+25
▪ Supplies and materials expense decrease due to major software acquisition in FY 2008	-15
▪ Contract services expenses increased due to Oracle financial system upgrade	+175
▪ Equipment expenses increase associated with IT Hardware, Oracle hardware, and replacement generator	+188
▪ Working Capital Fund increased to reflect headquarters operating expenses	+1
Subtotal, Other Related Expenses	+499
Total Funding Change, Program Direction	**+1,016**

Support Services by Category

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Management and Professional Support Services			
Co-sponsored energy efficiency services and renewable energy acquisition support for municipal and cooperative utilities	37	41	60
Total, Management and Professional Support Services	37	41	60

Other Related Expenses by Category

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Other Related Expenses			
Rent to GSA	340	347	355
Rent to Others	8	9	9
Audit of Financial Statements	160	163	250
Communications, Utilities, Misc.	264	262	306
Printing and Reproduction	7	4	4
Tuition	25	30	16
Maintenance Agreements	106	102	127
Supplies and Materials	58	129	114
Contract Services	236	241	416
Equipment	154	100	288
Working Capital Fund	30	31	32
Total, Other Related Expenses	1,388	1,418	1,917

Service Area Map

Revenue and Receipts

	(in thousands)						
	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Southeastern Power Administration							
Gross Revenues	206,862	239,736	240,268	241,696	242,802	243,964	257,332
Net Billing (Credited as an Offsetting Receipt)	-14,485	-13,802	-14,002	-14,282	-14,567	-14,859	-15,156
Total Cash Receipts	192,377	225,934	226,266	227,414	228,235	229,105	242,176
Continuing Fund	-36,000	0	0	0	0	0	0
Use of Offsetting Collections to fund PPW	-32,713	-48,413	-49,520	-50,510	-51,521	-52,551	-53,602
Total Offsetting Collections	123,664	177,521	176,746	176,904	176,714	176,554	188,574
Cumberland Rehabilitation	-8,000	-8,000	-9,000	-6,000	-3,000	-9,000	0
GA-AL-SC Rehabilitation	-3,000	-3,000	-1,000	-1,000	-1,000	-1,000	-1,000
Kerr-Philpott Rehabilitation	0	-400	-600	-600	-600	-600	-700
Total Proprietary Receipts	112,664	166,121	166,146	169,304	172,114	165,954	186,874
Percent of Sales to Preference Customers	99%	99%	99%	99%	99%	99%	99%
Energy Sales and Power Marketed (megawatt hours)	5,232,000	7,886,000	7,886,000	7,886,000	7,886,000	7,886,000	7,886,000

System Statistics

	FY 2007 Actual	FY 2008 Estimate	FY 2009 Estimate
Generating Capacity:			
Nameplate Capacity (KW)	3,392,375	3,392,375	3,392,375
Peak Capacity (KW) [a]	3,710,000	3,710,000	3,710,000
Generating Stations			
Generating Projects (Number)	22	22	22
Available Energy			
Energy from Streamflow (MWH)	4,554,857	7,459,272	7,459,272
Energy generated from Pumping (MWH)	678,132	427,128	427,128
Energy Purchased for Replacement (MWH)	150,110	75,000	75,000
Total, Energy available for marketing [b] (MWH)	5,383,099	7,961,400	7,961,400

[a] Southeastern markets capacity based on nameplate plus an overload factor. NERC requires that Southeastern keep a portion of the capacity in reserve for emergency purposes and to cover losses.
[b] Gross amount. Transmission losses are deducted from this amount to estimate the amount of energy marketed.

Power Marketed, Wheeled, or Exchanged by Project

Project	State	Plants	Installed Capacity (KW)	FY 2007 Estimated Power (GWH)	FY 2008 Estimated Power (GWH)	FY 2009 Estimated Power (GWH)
Kerr-Philpott System				430 *	463 *	463 *
John H. Kerr	VA-NC	1	204,000			
Philpott	VA	1	14,000			
Georgia-Alabama-South Carolina System				2,656 *	4,059 *	4,059 *
Allatoona	GA	1	74,000			
Buford	GA	1	86,000			
Carters	GA	1	500,000			
J. Strom Thurmond	GA-SC	1	280,000			
Walter F. George	GA-AL	1	130,000			
Hartwell	GA-SC	1	344,000			
R. F. Henry	AL	1	68,000			
Millers Ferry	AL	1	75,000			
West Point	GA-AL	1	73,375			
Richard B. Russell	GA-SC	1	600,000			
Jim Woodruff Project	FL-GA	1	30,000	181	237	237
Cumberland System				1,965 *	3,127 *	3,127 *
Barkley	KY	1	130,000			
Center Hill	TN	1	135,000			
Cheatham	TN	1	36,000			
Cordell Hull	TN	1	100,000			
Dale Hollow	TN	1	54,000			
Old Hickory	TN	1	100,000			
J. Percy Priest	TN	1	28,000			
Wolf Creek	TN	1	270,000			
Laurel	TN	1	61,000			
Total Power Marketed		22	3,392,375	5,232	7,886	7,886

Pending Litigation

Although Southeastern is not a party to the case listed below, we are monitoring it in order to assess any impacts the outcomes may have on Southeastern's operations.

Southeastern Federal Power Customers, Inc., (SeFPC) Lawsuit Against the Corps: In late 2000, SeFPC sued the Corps in U.S. District Court for the District of Columbia regarding the management of water withdrawal contracts and collection of revenues from certain water users in Georgia. The parties agreed to settlement discussions aided by a Court-sanctioned mediator and on January 9, 2003, a mediated settlement was reached by SeFPC, the Corps, the State of Georgia, and various Georgia water users holding Corps water withdrawal contracts at Lake Lanier (Buford Project). The settlement has been contested by the States of Alabama, Florida, and other intervening parties as being in conflict with prior pending litigation in Alabama and efforts by the three States to negotiate water compacts for the Alabama-Coosa-Tallapoosa (ACT) and Apalachicola-Chattahoochee-Flint (ACF) River Basins in Georgia, Florida, and Alabama. Also, it is argued that implementation of the settlement would adversely affect other litigation pending in Alabama and Georgia involving these parties.

On February 10, 2004, the Court overruled the objections of the States of Alabama and Florida to the Settlement Agreement and declared it valid and approved. The Court also held that the Settlement Agreement may be executed, filed, and thereafter performed in accordance with its terms, provided the preliminary injunction entered on October 15, 2003, in the Northern District of Alabama is first vacated. The order for injunction was appealed to the 11th Circuit of Appeals and the Court, after oral arguments, returned the Alabama order to the District Court for further consideration. Briefs and oral arguments were presented in late September, and no action has been taken by the Alabama District Court. Appeals from the February order were filed in April by Florida and Alabama and are currently pending for oral argument or other disposition by The District of Columbia Circuit Court of Appeals.

Alternative Financing

2007	Transmission	Purchase Power	Offsetting Collections	Net Billing	Appropriated Funds
Jim Woodruff System	0	895	-695	-200	0
Kerr-Philpott System	5,130	0	-5,130	0	0
GA-AL-SC System	19,423	12,000	-26,725	-4,698	0
Cumberland System	9,750	0	-163	-9,587	0
	34,303	12,895	-32,713	-14,485	0

2008	Transmission	Purchase Power	Offsetting Collections	Net Billing	Appropriated Funds
Jim Woodruff System	0	900	-700	-200	0
Kerr-Philpott System	4,913	0	-4,913	0	0
GA-AL-SC System	21,175	25,470	-42,630	-4,015	0
Cumberland System	9,757	0	-170	-9,587	0
	35,845	26,370	-48,413	-13,802	0

2009	Transmission	Purchase Power	Offsetting Collections	Net Billing	Appropriated Funds
Jim Woodruff System	0	900	-700	-200	0
Kerr-Philpott System	4,704	0	-4,704		0
GA-AL-SC System	20,707	27,449	-43,941	-4,215	0
Cumberland System	9,762	0	-175	-9,587	0
	35,173	28,349	-49,520	-14,002	0

Southwestern Power Administration

Southwestern Power Administration

Southwestern Power Administration

Proposed Appropriation Language

For necessary expenses of operation and maintenance of power transmission facilities and of marketing electric power and energy, for construction and acquisition of transmission lines, substations and appurtenant facilities, and for administrative expenses, including official reception and representation expenses in an amount not to exceed $1,500 in carrying out section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), as applied to the southwestern power area, [$30,442,000] *$28,414,000*, to remain available until expended: Provided, That, notwithstanding 31 U.S.C. 3302 up to $35,000,000 collected by the Southwestern Power Administration Pursuant to the Flood Control Act to recover purchase power and wheeling expenses shall be credited to this account as offsetting collections, to remain available until expended for the sole purpose of making purchase power and wheeling expenditures.

Southwestern Power Administration

Overview

Appropriation Summary by Program

(dollars in thousands)

	FY 2007 Current Appropriation	FY 2008 Original Appropriation	FY 2008 Adjustments	FY 2008 Current Appropriation [a]	FY 2009 Request
Southwestern Power Administration					
Operation and Maintenance	42,398	83,492	-277	83,215	89,186
Subtotal, Southwestern Power Administration	42,398	83,492	-277	83,215	89,186
Offsetting Collections, Purchase Power and Wheeling (PPW) [b]	-3,000	-35,000	--	-35,000	-35,000
Alternative Financing	-9,400	-18,050	--	-18,050	-25,772
Total, Southwestern Power Administration	29,998	30,442	-277	30,165	28,414

Preface

The Department of Energy (DOE) is leading the Nation forward to strengthen its national energy and economic security by promoting a diverse supply and delivery of reliable, affordable, and environmentally sound energy. Southwestern Power Administration (Southwestern) exists to meet its public responsibilities, consistent with the Flood Control Act of 1944, to market and reliably deliver Federal power, recover power costs, and repay the Federal investment consistent with sound business principles, giving preference to public bodies and cooperatives while encouraging the most widespread use of power, and implementing public policy.

Within the Southwestern appropriation, there is one program: Operation and Maintenance (four subprograms: Operation and Maintenance, Construction, Purchase Power and Wheeling, and Program Direction).

Mission

The mission of Southwestern is to market and reliably deliver Federal hydroelectric power with preference to public bodies and cooperatives. This is accomplished by maximizing the use of Federal assets to repay the Federal investment and participating with other water resource users in an effort to balance their diverse interests with power needs within broad parameters set by the U. S. Army Corps of Engineers (Corps), and implementing public policy.

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[a] Southwestern Power Administration's FY 2008 Current Appropriation reflects a 0.91% rescission in accordance with Public Law No. 110-161, Consolidated Appropriations Act, 2008, in the amount of $277,022 (Operations and Maintenance $86,204; Construction $30,947; and Program Direction $159,871).

[b] Southwestern's budget request for the Purchase Power and Wheeling subprogram reflects anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions.

Benefits

Southwestern's appropriation supports DOE's Energy Strategic Theme 1 by enabling the delivery of reliable, affordable and environmentally sound energy, and operating a reliable transmission system which is an integral part of the Nation's transmission grid. Southwestern, in conjunction with the Corps, participates in this effort by managing the multipurpose operation of the Federal hydropower system. This enables effective marketing, generation, and delivery of clean, reliable, cost-based electric power.

Southwestern's program provides the Nation numerous benefits, which include:

- Operating a reliable Federal power system in an effective, cost efficient, and environmentally sound manner while meeting National utility performance standards and balancing the diverse interests of other water resource users.
- Producing power at the lowest cost-based rates possible, consistent with sound business practices.
- Repaying the American taxpayers' investments in the Federal power system.
- Delivering reliable power to its customers.
- Providing approximately $480 million in economic benefits under average water conditions.
- Providing regional power restoration assistance to other non-hydropower generation sources during outage emergencies.
- Repaying the costs of operation of the Federal hydropower system with revenues from power customers.
- Supporting North American Electric Reliability Corporation (NERC) requirements.
- Supporting Federal Energy Regulatory Commission (FERC) requirements consistent with Federal statute.

Southwestern contributes program benefits in support of Climate Change activities by, reducing greenhouse gas emissions and fossil fuel usage. Annually, Southwestern produces on average 5,570 gigawatt-hours of clean renewable hydroelectric energy. That energy production reduces emissions of carbon dioxide by 4.6 million tons per year, sulfur dioxide by 13,900 tons per year, and nitrogen oxides by 11,100 tons per year. Additionally, Southwestern's annual energy production replaces that which could be produced by burning 9.2 million barrels of fuel oil, or 2.7 million tons of coal, or 56.5 billion cubic feet of natural gas.

Strategic Themes and Goals and GPRA Unit Program Goal

The DOE Strategic Plan identifies five Strategic Themes (one each for nuclear, energy, science, management, and environmental aspects of the mission) plus 16 Strategic Goals that tie to the Strategic Themes. Southwestern's appropriation supports the following theme and goal:

Strategic Theme 1, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

Strategic Goal 1.3, Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

The program funded within Southwestern's appropriation has one GPRA Unit Program Goal that contributes to the Strategic Goals in the "goal cascade." This goal is:

GPRA Unit Program Goal 1.3.24.00: Southwestern Power Administration: Market and Deliver Federal Power: Provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

Contribution to Strategic Goal

Southwestern contributes to DOE's Strategic Goal through four subprograms (Program Direction, Operations and Maintenance, Construction, and Purchase Power and Wheeling) supported by appropriations, Federal power receipts, and alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances). This is accomplished by marketing and delivering all available hydroelectric power from the Corps' dams while working with other water resource users to balance their diverse interests with power needs within broad parameters set by the Corps; operating and maintaining a Federal power system, which is an integral part of the Nation's electrical grid, in an effective and cost efficient manner to assure reliability; and maximizing the use of Federal assets to repay the investment (principal and interest) as well as operation and maintenance costs of the Southwestern Federal power system while supporting the President's Management Agenda initiatives.

Funding by Strategic and GPRA Unit Program Goal

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Strategic Goal 1.3, Energy Infrastructure			
GPRA Unit Program Goal 1.3.24.00, Operation and Maintenance	42,398	83,215	89,186
Total, Strategic Goal 1.3 (Southwestern Power Administration)	42,398	83,215	89,186

Annual Performance Results and Targets

FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Results	FY 2008 Targets	FY 2009 Targets
Strategic Goal 1.3, Energy Infrastructure GPRA Unit Program Goal 1.3.24.00: Southwestern Power Administration, Operation and Maintenance					
Attain average NERC compliance ratings of 100 or higher for Control Performance Standard 1, and 90 or above for Control Performance Standard 2. (ER9-3) GREEN Actual: CPS 1: 183.8 CPS 2: 99.6	Meet industry averages (CPS1: 162.0 and CPS2: 96.7) and at a minimum, meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. GREEN Actual: CPS 1: 186.74 CPS 2: 99.40	Meet industry averages (CPS1: 161.8 and CPS2: 97.2) and at a minimum, meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. GREEN Actual: CPS 1: 180.23 CPS 2: 99.18	Meet industry averages and at a minimum, meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. GREEN Actual: CPS 1: 199.26 CPS 2: 99.61	Meet industry averages and at a minimum, meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances.	Meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90 and meet or exceed industry averages. CPS1 measures a generating system's performance at matching supply to changing demand requirements and supporting desired system frequency in one minute increments. CPS2 measures a generating system's performance at limiting the magnitude of generation and demand imbalances in ten minute increments.
Meet planned annual repayment of principal on Federal power investment. (ER9-3) GREEN Actual: $29.2 million	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower.[a] GREEN Actual: Southwestern: $0.0109 National industry average: $0.0126 Therefore, Southwestern less than National industry average.	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower. GREEN Actual: Southwestern: $0.0116 National industry average: $0.0136 Therefore, Southwestern is less than National industry average.	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower. GREEN Actual: Southwestern: $0.0126 National industry average: $0.0137 Therefore, Southwestern is less than National industry average.	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower.	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower.

[a] National average for hydropower O&M cost per kilowatt-hour is derived from a sampling of hydropower utilities' annual reports, the Federal Energy Regulatory Commission's Form 1, and the Energy Information Administration's Form 412.

FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Results	FY 2008 Targets	FY 2009 Targets
Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 5.3, or the Bureau of Labor Statistics' industry rate (3.7), whichever is lower. (ER9-3) GREEN Actual: 2.6 recordable injuries per 200,000 hours worked.	Provide $457 million in economic benefits to the region from the sale of hydroelectric power (under average water conditions). GREEN Actual: $488 million	Provide $462 million in economic benefits to the region from the sale of hydroelectric power (under average water conditions). YELLOW Actual: $322 million	Provide $468 million in economic benefits to the region from the sale of hydroelectric power (under average water conditions). GREEN Actual: $471.6 million	Provide $474 million in economic benefits to the region from the sale of hydroelectric power (under average water conditions).	
Repay the Federal investment[a] within the required repayment period. (ER9-3) GREEN Target: $2,552,184 Actual: $4,500,495	Repay the Federal investment within the required repayment period. GREEN Target: $1,121,315 Actual: $27,206,471	Repay the Federal investment within the required repayment period. GREEN Target: $699,855 Actual: $20,435,196	Repay the Federal investment within the required repayment period. GREEN Target: $586,991 Actual: $28,018,029	Repay the Federal investment within the required repayment period. Target: $920,712	Repay the Federal investment within the required repayment period. Target: $2,263,733
System Reliability Performance: Achieve a System Average Interruption Duration Index (SAIDI) of not more than 150 minutes of total preventable outages per year. (ER9-3) GREEN Actual: < 150 minutes of total preventable outages.	Provide reliable service to customers annually under normal operations, by not allowing system voltage to fall below 95% of nominal (e.g. 161kV) for more than 30 minutes during any preventable condition. GREEN Actual: Southwestern did not incur any violations where system voltage fell below 95% if nominal for more than 30 minutes of preventable condition.	Operate the transmission system so there are no more than 3 preventable outages annually. GREEN Actual: Southwestern incurred one preventable outage.	Operate the transmission system so there are no more than 3 preventable outages annually. GREEN Actual: Southwestern incurred no preventable outages.	Operate the transmission system so there are no more than 3 preventable outages annually.	Operate the transmission system so there are no more than 3 preventable outages annually.

[a] Estimates are being used because actual audited numbers related to the U.S. Army Corps of Engineers are not available.

Means and Strategies

Southwestern will use various means and strategies to achieve its GPRA Unit Program goal. However, various external factors may impact the ability to achieve this goal. Southwestern also collaborates with others to meet its goal.

Southwestern will implement the following means:

- Achieve and maintain financial integrity.
- Maintain power system reliability.
- Operate the Federal power system effectively and efficiently.
- Provide power at the lowest possible cost.
- Provide economic benefits to the region.

Southwestern will implement the following strategies:

- Market all available hydropower generated at the Corps multipurpose projects and work with the Corps, states, cooperatives, and municipalities to meet statutory requirements while balancing the interests of other water users.
- Assure power rates are sufficient to repay all annual operating costs and the Federal investment with interest by conducting annual power repayment studies and submitting rate adjustments to the Department of Energy (DOE) and the FERC for approval.
- Meet Southwestern's limited 1200-hour peaking power contractual obligations with necessary purchase power and wheeling through the use of Federal power receipts; alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances); and Continuing Fund Authority, as necessary in years of below average hydropower generation.
- Utilize the following funding mechanisms: appropriations, use of Federal power receipts, and alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances).
- Maintain a diverse and knowledgeable workforce through employee training, skills gap analysis, leadership development, retention programs, and aggressive recruitment activities.
- Meet NERC requirements by documenting Southwestern's compliance with the latest NERC standards and performing certification and annual emergency operations training for power system dispatchers.
- Maintain the security of the Federal power system, facilities, and information technology (IT) systems.
- Address changes in the electric utility industry, technology, and workload by moving administrative and indirect positions to direct ("front line") positions as opportunities arise.
- Maximize the capabilities of business systems to improve processes and provide greater efficiency.

These strategies will result in a well-maintained, reliable Federal power system, and an exemplary workforce to operate and maintain the system in the most effective and cost efficient manner possible.

The following external factors could impact Southwestern's ability to achieve its program goal:

- Southwestern's program goal could be impacted by weather, natural disasters, transmission line constraints, new load patterns, deregulation of the electricity market, changing electric industry organizational structures, equipment failure, Congressional requirements, power markets, revenue factors, additions to other utilities' transmission systems interconnected with the Federal system, and other unforeseen requirements.

Successful collaboration of the Federal hydropower partners is necessary for Southwestern to achieve its program goal. Southwestern coordinates its operational activities with the Corps, customers, competing resources interests, the Southwest Power Pool Regional Transmission Organization, and Congress to provide the most efficient and effective use of Federal assets and to ensure NERC and regional reliability council standards are met.

Validation and Verification

Southwestern routinely conducts various internal reviews, studies, and audits to validate and verify program performance. Southwestern's program also is subject to continuing review by external entities such as Congress, the Government Accountability Office (GAO), the DOE's Inspector General, FERC, the U.S. Environmental Protection Agency, the Office of Personnel Management, the Office of Management and Budget (OMB), DOE, NERC, the regional electric reliability council, and Southwestern's Federal power customers.

Achievement of Southwestern's objectives is evaluated in the context of mission responsibilities and the continued impacts of external factors. Each objective has performance targets that are reported quarterly to DOE. Southwestern establishes a corrective plan of action to improve any performance below established quarterly standards. Measuring performance against these targets indicates whether Southwestern is achieving its objectives.

Program Assessment Rating Tool (PART)

DOE implemented a tool to evaluate selected programs. PART was developed by OMB to provide a standardized way to assess the effectiveness of the Federal Government's portfolio of programs. The structured framework of the PART provides a means through which programs can assess their activities differently than through traditional reviews.

The current focus is to establish outcome- and output-oriented goals, the successful completion of which will lead to benefits to the public, such as operational efficiency, increased national security and energy security, and improved environmental conditions. DOE has incorporated feedback from OMB in the FY 2009 Budget Request, and DOE will take the necessary steps to continue improving performance.

Southwestern received a "Moderately Effective" PART rating from OMB for both the FY 2004 and FY 2005 budget cycles. This rating indicated that Southwestern needed to make improvements to long- and short-term goals. In February 2004, Southwestern took the lead to improve its goals by working with its OMB Examiner. Southwestern and OMB agreed that the new long- and short-term performance goals satisfied the PART criteria. These mutually agreed to performance goals and targets, initially reflected in the FY 2006 budget and carried forward every budget year since, provide a strong link to Southwestern's funding request.

In addition, Southwestern continues to work with OMB to update PART goals and resolve any significant findings and recommendations. This collaboration has improved Southwestern's ability to utilize the PART in decision-making and budget prioritization processes.

Significant Policy or Program Shifts

- The Administration supports reclassification of receipts from mandatory to discretionary (net zero appropriations) for the annual operating expenses of Southeastern, Southwestern, and Western Area Power Administrations (PMAs). Reclassification of receipts in this manner would allow the PMA programs to benefit from the alignment of PMA receipts with their annual (non-capital) expenditures provided by appropriations. This alignment would foster increased planning certainty for the PMA programs, which would ultimately improve the reliability and operating efficiency of the Federal power system. The Administration will continue to pursue reclassification of receipts through changes to the existing authorizing statute or by other means.

Southwestern Power Administration

Funding by Site by Program

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Southwestern Power Administration	42,398	83,215	89,186
Total, Southwestern Power Administration	42,398	83,215	89,186

Site Description

An Agency of the Department of Energy, Southwestern Power Administration (Southwestern) was created in 1943 to market and deliver power and energy produced at U.S. Army Corps of Engineers (Corps) hydroelectric power projects. Southwestern markets and delivers power at wholesale rates to 78 municipal utilities, 22 rural electric cooperatives, and three government entities in the six States of Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas. In order to integrate the operation of the Federal hydroelectric generating plants and to transmit power from 24 multi-purpose Corps' dams to customers, Southwestern operates and maintains 1,380 miles of high-voltage transmission line, 24[a] substations, and 47 microwave and very high frequency radio sites. Southwestern operates from its Headquarters in Tulsa, Oklahoma, a Dispatch Center in Springfield, Missouri, and maintenance facilities in Jonesboro, Arkansas; Gore, Oklahoma; and Springfield, Missouri.

[a] This number will increase upon the transfer of generation substations to Southwestern.

Operation and Maintenance

Funding Profile by Subprogram

(dollars in thousands)

	FY 2007 Current Appropriation	FY 2008 Original Appropriation	FY 2008 Adjustments	FY 2008 Current Appropriation [a]	FY 2009 Request
Operation and Maintenance					
Program Direction (PD)	20,782	22,214	-160	22,054	24,330
Operations and Maintenance (O&M)	5,604	11,978	-86	11,892	12,865
Construction (CN)	3,612	4,300	-31	4,269	5,991
Purchase Power and Wheeling (PPW) [b]	12,400	45,000	--	45,000	46,000
Subtotal, Operation and Maintenance	42,398	83,492	-277	83,215	89,186
Offsetting Collections, PPW	-3,000	-35,000	--	-35,000	-35,000
Alternative Financing, PD	n/a	-877	--	-877	-2,200
Alternative Financing, O&M	n/a	-6,304	--	-6,304	-9,381
Alternative Financing, CN	n/a	-869	--	-869	-3,191
Alternative Financing, PPW	-9,400	-10,000	--	-10,000	-11,000
Total, Operation and Maintenance	29,998	30,442	-277	30,165	28,414

Public Law Authorizations:

Public Law No. 78-534, Section 5, Flood Control Act of 1944
Public Law No. 95-91, Section 302, DOE Organization Act of 1977
Public Law No. 100-71, Supplemental Appropriations Act, 1987
Public Law No. 101-101, Title III, Continuing Fund (amended 1989)
Public Law No. 102-486, Section 721, Energy Policy Act of 1992
Public Law No. 108-137, Appropriations Act, FY 2004

Mission

The mission of the Operation and Maintenance program is to market and reliably deliver Federal hydroelectric power with preference to public bodies and cooperatives. This is accomplished by maximizing the use of Federal assets to repay the Federal investment and participating with other water resource users in an effort to balance their diverse interests with power needs within broad parameters set by the U.S. Army Corps of Engineers (Corps), and implementing public policy.

[a] Southwestern Power Administration's FY 2008 Current Appropriation reflects a 0.91% rescission in accordance with Public Law No. 110-161, Consolidated Appropriations Act, 2008, in the amount of $277,022 (Operations and Maintenance $86,204; Construction $30,947; and Program Direction $159,871).
[b] Southwestern's budget request for the Purchase Power and Wheeling subprogram reflects anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions.

Operations and Maintenance

Funding Schedule by Activity

	(dollars in thousands)		
	FY 2007	FY 2008 [a]	FY 2009
Operations and Maintenance (O&M)			
Power Marketing	200	1,028	1,773
Operations	2,834	4,321	3,575
Maintenance	2,270	6,118	6,194
Capitalized Movable Equipment	300	425	1,323
Subtotal, Operations and Maintenance	5,604	11,892	12,865
Alternative Financing	n/a	-6,304	-9,381
Total, Operations and Maintenance	5,604	5,588	3,484

Description

The mission of the Operations and Maintenance subprogram is to assure continued reliability of the Federal power system by replacing aging infrastructure and removing constraints that would impede power flows, thus meeting the expectations of the 2005 Energy Policy Act (EPACT), National Energy Policy (NEP), and the Department of Energy's (DOE) Strategic Plan. This subprogram fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects the Southwestern Power Administration's (Southwestern) program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

The activities of the Operations and Maintenance subprogram are critical components in maintaining the reliability of the Federal power system facilities, which are part of the Nation's interconnected generation and transmission system. Through the use of renewable hydroelectric energy, Southwestern provides clean, safe, reliable, cost-based electric power to its customers while limiting environmental impacts. EPACT, NEP, and DOE's Strategic Plan reinforce the importance of renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past, current, and future energy supply and Southwestern's "important role in meeting demand" by supplying hydroelectric power to its customers. All emphasize the need to repair, maintain, and improve the transmission and generation infrastructure to avoid loss of reliability. Southwestern also has the capability to provide reliable off-site power to help restore other power generation sources during outage emergencies.

Southwestern's compliance with North American Electric Reliability Corporation (NERC) standards and participation in the regional electric reliability council and the Regional Transmission Organization (RTO) in Southwestern's marketing area, consistent with EPACT, reinforces Southwestern's role as part of the Nation's interconnected electric grid. DOE identified the Supervisory Control and Data

[a] Southwestern Power Administration's FY 2008 Current Appropriation reflects a 0.91% rescission in accordance with Public Law No. 110-161, Consolidated Appropriations Act, 2008, in the amount of $277,022 (Operations and Maintenance $86,204; Construction $30,947; and Program Direction $159,871).

Acquisition/Energy Management System (SCADA/EMS), transmission lines, substations, and communication facilities as critical infrastructure. As the demand for the transmission of power increases on the Nation's power systems, the need to maintain, repair, and provide for improvements on the Federal power system is critical in assuring reliable delivery.

Southwestern will use appropriations and will continue to use alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances) with customers and others who provide services or funds to assure a dependable and reliable Federal power system. Southwestern's authority to use net billing and bill crediting is inherent in the authority provided by the Flood Control Act of 1944, and has been affirmed by the Comptroller General.[a]

Southwestern's planned Operations and Maintenance projects are subject to change based on unanticipated equipment failure, customer needs, and weather conditions. The realities of maintaining a complex interconnected power system means unforeseen priority projects will arise periodically causing a reprioritization of planned projects. All projects share the commonality of maintaining, repairing, and improving the aging and deteriorating infrastructure to ensure the reliability of the Federal power system.

Detailed Justification

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Power Marketing	**200**	**1,028**	**1,773**

The Power Marketing activity funds technical and economic studies to support Southwestern's transmission planning, water resources, communications, and maintenance activities. Technical and economic studies provide data to analyze and evaluate the impacts of proposed operational changes and decision-making based on cost/benefit analyses. Funding is also required for Southwestern's participation in the RTO and to provide regional power restoration assistance to other non-hydropower generation sources during outage emergencies. The NEP identified bottlenecks in the Nation's interconnected electrical grid, which could impede power flows. Studies to identify any constraints on Southwestern's system will continue to be conducted. These studies show how the marketing and delivery of power is operationally impacted.

Southwestern's transmission line sag profiles have not been updated since the lines were originally installed. Southwestern plans to conduct a transmission line sag surveys in FY 2009; these new surveys will provide the necessary information for updating transmission line plan and profile drawings. These surveys will allow further decisions to be made on whether Southwestern needs to reconductor or resag the transmission line in compliance with the National Electrical Safety Code. Southwestern estimates 150 to 200 miles of transmission line will benefit from this survey.

Southwestern currently has transmission assets that are within other utilities' control areas. This arrangement requires Southwestern to provide power losses to those other utilities, and increases the complexity of operating Southwestern's transmission system during both normal and emergency conditions, as well as the complexity of performing proper settlement accounting and regional tariff administration under the RTO.

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[a] Honorable Secretary of the Interior B-125, 127 (February 14, 1956) available at WL 3064 (Comp. Gen.).

	(dollars in thousands)	
FY 2007	FY 2008	FY 2009

The funding level for this activity is derived from Southwestern's engineering plan, negotiated architect/engineering contracts, and the number of studies required per year. The increase in funding for this activity reflects a change in Southwestern's control area boundary to reduce power losses provided, thereby saving annual costs, and enabling easier reconciliation of power billing and operations with the regional reliability council and the RTO.

	FY 2007	FY 2008	FY 2009
Operations	**2,834**	**4,321**	**3,575**

The Operations activity funds communication activities associated with the dispatch and delivery of power; environmental, safety and health activities; and other transmission activity costs such as physical security, cyber security, and day-to-day power dispatch functions.

	FY 2007	FY 2008	FY 2009
▪ **Communications**	**1,849**	**2,884**	**2,349**

This subactivity funds telemetering improvements, technical support to protect cyber infrastructure, SCADA/EMS maintenance agreements, a communication alarm system replacement, an e-tagging system that electronically schedules power for customers, load forecasting, digital test equipment, fee for spectrum, and supplies and materials. The telemetering improvements include replacement of obsolete power and energy accounting equipment and modification of existing remote terminal units that improve the reliability of the power system, specifically in the areas of monitoring and control. Funding is required for upgrades that enable Southwestern to meet the goals of the EPACT, NEP, and DOE's Strategic Plan by replacing deteriorating infrastructure while assuring reliability and continuing to actively participate in the RTO. The funding level for communications maintenance is derived from maintenance history, the age of equipment, expected life span, annual diagnostic maintenance testing, and historical pricing information. The decrease in funding of this subactivity reflects completion of the communication alarm system replacement.

	FY 2007	FY 2008	FY 2009
▪ **Environmental, Safety and Health**	**525**	**1,176**	**995**

This subactivity funds environmental activities including waste disposal/clean-up of oil and polychlorinated biphenyl contaminates from old circuit breakers and transformers; environmental assessments for threatened and endangered species; property transfers; wetland assessments; environmental library access; Toxic Substance Control Act and Resource Conservation Recovery Act compliance; contractor services; and requirements of the Environmental Protection Program as identified in DOE Order 450.1. The Safety and Health Program activities require funding for Occupational Safety and Health Administration compliance, substation grounding and drainage, aviation safety, industrial hygiene, medical examinations, medical officer, wellness program, safety equipment, and first aid supplies. The decrease in funding reflects completion of the Spill Prevention, Control, and Countermeasure plans and completion of environmental reviews.

	FY 2007	FY 2008	FY 2009
(dollars in thousands)			
▪ **Other Transmission**	**460**	**261**	**231**

This subactivity funds physical security, field utility costs for substations and microwave sites, and the day-to-day expenses of the dispatch center. Southwestern completed vulnerability and risk assessments and its graded approach in applying risk mitigation strategies to determine security improvements of its critical assets; these improvements have been implemented. The decrease in funding for this subactivity is due to reduced physical security requirements.

Maintenance	**2,270**	**6,118**	**6,194**

The Maintenance activity funds routine repair, maintenance, and improvement of Southwestern's 24[a] substations and 1,380 miles of high-voltage transmission lines, and assures power is reliably and safely delivered to customers. Southwestern's initial facilities, which were built approximately 60 years ago, are constantly evaluated through the maintenance management information system (MMIS). The funding level for this activity is derived from the MMIS (age, risk of failure, life cycle of equipment) and field crew evaluation. Internal and external factors include obsolescence of technology and lack of replacement parts. These variables are used in determining the level of funding required for a fiscal year. This budget request reflects Southwestern's assessment of the funding required to assure continued reliability of the Federal power system by replacing aging equipment and removing constraints that impede power flows, thus meeting the expectations of the NEP and DOE's Strategic Plan.

▪ **Substation Maintenance**	**1,419**	**4,663**	**4,838**

This subactivity funds a transformer, power circuit breakers, disconnect switches, protective relays and related equipment, computer aided drafting and design, revenue meters, vehicle maintenance, fuel, and other equipment to reliably perform general maintenance projects while maintaining the Federal power system as required by Southwestern's participation in a regional electric reliability council. The funding level for this subactivity is derived from MMIS data, which provides the age and condition of the existing equipment facilitating projection of maintenance intervals. The increase in funding for this subactivity reflects Southwestern's planned replacements in order to maintain reliability of the power system while accommodating increased loads on the Federal power facilities resulting from interconnection and open access requests from other utilities.

▪ **Transmission Line Maintenance**	**851**	**1,455**	**1,356**

This subactivity funds the purchase and maintenance of wood and steel structures, crossarms and braces, right-of-way (ROW) clearing, herbicide application, aerial patrol of the transmission system to identify maintenance needs, routine vehicle repair and maintenance, tractor-trailers, heavy equipment, and fuel. The quantity of steel and wood poles and crossarms and high voltage insulators is derived from MMIS data. Emphasis continues to be placed on ROW clearing since NERC identified improper/insufficient ROW clearing as a major factor in potential blackouts. The funding level is appropriate for the number of structures and components to be replaced and the

[a] This number will increase upon the transfer of generation substations to Southwestern.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

miles of ROW to be cleared as set forth by Southwestern's maintenance plans in meeting the goals of the EPACT and NEP to maintain a reliable transmission system. The decrease in funding reflects shifting tractors, hydroaxes, forklifts, and cranes from transmission line maintenance to capitalized movable equipment offset by an increase in funding for sonic testing of poles.

Capitalized Movable Equipment	**300**	**425**	**1,323**

The Capitalized Movable Equipment activity funds the replacement of vehicles, tractor-trailers, and heavy equipment used for maintenance and repair of the transmission system and facilities. The replacement criteria Southwestern utilizes for specialized equipment needed to maintain 1,380 miles of transmission line is derived from the General Services Administration (GSA) and DOE guidelines based on operation duration and age. These vehicles exceed their useful lives and require high levels of maintenance. The vehicle cost estimates are derived from GSA pricing schedules. The increase in funding for this activity reflects shifting tractors, hydroaxes, forklifts, and cranes from transmission line maintenance to capitalized movable equipment.

Total, Operations and Maintenance	**5,604**	**11,892**	**12,865**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Power Marketing	
▪ Increase reflects funding for the control area boundary project and a transmission line sag survey.	+745
Operations	
▪ Decrease reflects completion of an alarm system replacement project and environmental contract support and safety equipment.	-746
Maintenance	
▪ Increase reflects substation supplies and materials offset by a decrease from shifting tractors, hydroaxes, forklifts, and cranes from transmission line maintenance to capitalized movable equipment offset by an increase in funding for sonic testing of poles.	+76
Capitalized Movable Equipment	
▪ Increase reflects shifting tractors, hydroaxes, forklifts, and cranes from transmission line maintenance to capitalized movable equipment.	+898
Total Funding Change, Operations and Maintenance	**+973**

Construction

Funding Schedule by Activity

	(dollars in thousands)		
	FY 2007	FY 2008 [a]	FY 2009
Construction			
Transmission System	3,612	4,269	5,991
Subtotal, Construction	3,612	4,269	5,991
Alternative Financing	n/a	-869	-3,191
Total, Construction	3,612	3,400	2,800

Description

The mission of the Construction subprogram is to assure continued reliability of the Federal power system by providing for additions, modifications, replacements, and interconnections to the transmission, substation, and communication facilities, thus meeting the expectations of the 2005 Energy Policy Act (EPACT), National Energy Policy (NEP), and the Department of Energy's (DOE) Strategic Plan. This subprogram fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects Southwestern Power Administration's (Southwestern) program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

The activities of the Construction subprogram enable Southwestern to market and deliver Federal hydropower in the most reliable, safe, efficient, cost effective manner to meet the operational criteria required as a participant in the National electrical grid while avoiding transmission infrastructure deterioration. EPACT, NEP, and DOE's Strategic Plan reinforce the importance of renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past, current, and future energy supply and Southwestern's "important role in meeting demand" by supplying hydroelectric power to its customers. Southwestern's participation in the regional electric reliability council and the Regional Transmission Organization (RTO), encouraged by DOE's National Transmission Grid Study, reinforces Southwestern's role as an integral part of the Nation's interconnected generation and transmission system. As the demand for the transmission of power on the Nation's power systems increases, the need to provide improvements, replacements, and interconnections on the Federal power system, which require expansion of or additions to existing facilities, is critical in assuring reliable delivery.

Southwestern will continue to use appropriations and alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances) with customers and others who provide services or funds to assure a dependable and reliable Federal power system. Southwestern's

[a] Southwestern Power Administration's FY 2008 Current Appropriation reflects a 0.91% rescission in accordance with Public Law No. 110-161, Consolidated Appropriations Act, 2008, in the amount of $277,022 (Operations and Maintenance $86,204; Construction $30,947; and Program Direction $159,871).

authority to use net billing and bill crediting is inherent in the authority provided by the Flood Control Act of 1944, and has been affirmed by the Comptroller General.[a]

Southwestern's planned Construction projects are subject to change based on unanticipated equipment failure, customer needs, and weather conditions. The realities of maintaining a complex interconnected power system means unforeseen priority projects will arise periodically causing a reprioritization of planned projects. All projects share the commonality of replacing aging and deteriorating infrastructure necessary to maintain the reliability of the Federal power system.

Detailed Justification

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Transmission System	**3,612**	**4,269**	**5,991**

This activity funds all construction projects that require expansion of or additions to existing facilities. System reliability is assured by replacing aging and deteriorating equipment, thereby removing constraints that limit power flows. The projects reflect Southwestern's efforts to reduce the risk of extended service outages, avoid more costly replacements in the future, and support the increased transmission system usage. The funding level for this activity is derived from internal and external management decisions and maintenance crew observations regarding system age, risk of equipment failure, life cycles, obsolescence of technology, unavailable replacement parts, budget constraints, cost, and demand for more capacity. These variables are assessed and incorporated into Southwestern's 10-year construction plan.

	FY 2007	FY 2008	FY 2009
▪ **Substation Upgrades**	**0**	**0**	**2,200**

This subactivity funds a high priority upgrade of the station bus and associated equipment at the Bull Shoals Dam switchyard that has been identified by the Southwest Power Pool RTO as necessary to relieve a transmission constraint.

	FY 2007	FY 2008	FY 2009
▪ **Communication Equipment**	**3,612**	**2,969**	**3,791**

This subactivity funds all communication equipment and microwave radio and tower replacements that are planned to provide improved system reliability and reduce future maintenance and equipment costs. This subactivity also provides funding for microwave radios and microwave tower additions, replacements, and modifications that will allow Southwestern to complete an important communication ring within its network that will increase the reliability of communications with the generating plants and substations in the Oklahoma region. The communication system provides for the transfer of voice and data traffic to allow monitoring and control of power system generation and transmission assets. The increase in funding for FY 2009 reflects the number of planned microwave radio and tower replacements.

In December 2004, the Congress passed and the President signed the Commercial Spectrum Enhancement Act (CSEA, Title II of P.L. 108-494), creating the Spectrum Relocation Fund (SRF) to streamline the relocation of Federal systems from certain spectrum bands to accommodate

[a] Honorable Secretary of the Interior B-125, 127 (February 14, 1956) available at WL 3064 (Comp. Gen.).

	(dollars in thousands)	
FY 2007	FY 2008	FY 2009

commercial use by facilitating reimbursement to affected agencies of relocation costs. In FY 2007, Southwestern received $8.1 million in spectrum relocation funds, as approved by the Office of Management and Budget, and as reported to the Congress by the Department of Commerce in December 2005. These funds are mandatory and will remain available until expended, and agencies will return to the SRF any amounts received in excess of actual relocation costs. Frequency spectrum activities were funded from spectrum auction proceeds, thus no funding is provided in this subactivity.

	FY 2007	FY 2008	FY 2009
▪ **Transmission Upgrades**	**0**	**1,300**	**0**

This subactivity funds transmission system upgrades as mandated by the RTO. The RTO in Southwestern's marketing area performed a system impact study that resulted in the requirement to re-conductor the Idalia-Asherville line. This project improves the transmission infrastructure by alleviating power flow constraints and eliminating line overloading as required under DOE's National Transmission Grid Study and the NEP. No additional funding is required for this subactivity in FY 2009.

	FY 2007	FY 2008	FY 2009
Total, Construction	**3,612**	**4,269**	**5,991**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Transmission System	
▪ The net increase in funding reflects an upgrade at the Bull Shoals switchyard offset by a reduction in transmission upgrades.	+1,722
Total Funding Change, Construction	**+1,722**

Purchase Power and Wheeling

Funding Schedule by Activity

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Purchase Power and Wheeling (PPW) [a]			
System Support	9,100	41,500	42,500
Other Contractual Services	3,300	3,500	3,500
Total, PPW	12,400	45,000	46,000
Use of Alternative Financing – Reimbursable Authority (customer advances), Net Billing, Bill Crediting:			
Purchase Power	-2,825	-3,425	-4,425
Power Losses	-3,300	-3,300	-3,300
Wheeling	-3,275	-3,275	-3,275
Total, Alternative Financing	-9,400	-10,000	-11,000
Subtotal, PPW	3,000	35,000	35,000
Offsetting Collections	-3,000	-35,000	-35,000
Total, Purchase Power and Wheeling	0	0	0

Description

The mission of the Purchase Power and Wheeling (PPW) subprogram is to provide for the purchase of energy to meet limited peaking power contractual obligations and the delivery of Federal power. Such purchases are blended with the available Federal hydroelectric power and energy to provide a more beneficial and reliable product while assuring repayment of the Federal investment plus interest, thus meeting the expectations of the 2005 Energy Policy Act (EPACT), National Energy Policy (NEP), and the Department of Energy's (DOE) Strategic Plan. This subprogram fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects Southwestern Power Administration's (Southwestern) program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

The activities of the PPW subprogram provide for the purchase of energy to meet limited peaking power contractual obligations to assure the marketability of the Federal resource and repayment of the Federal investment. Southwestern's power sales contracts provide for only 1200 hours of peaking power per year, representing a portion of its customers' firm load requirements. The customers provide their own resources and/or purchases for the remainder of their firm loads. This subprogram also provides for wheeling services that deliver Federal power to optimize the operation of the hydroelectric facilities marketed by Southwestern. EPACT, NEP, and DOE's Strategic Plan reinforce the importance of

[a] Southwestern's budget request for the Purchase Power and Wheeling subprogram reflects anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions.

domestic, renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past, current, and future energy supply and Southwestern's "important role in meeting demand" by supplying hydroelectric power to its customers.

The reduced level of energy banking available from other electric utilities requires Southwestern to use alternative financing to fund power deliveries. Southwestern will continue to use Federal power receipts and alternative financing methods, including net billing, bill crediting, and/or reimbursable authority (customer advances) to fund this subprogram. When hydro generation is significantly below-normal due to severe drought conditions, Southwestern will utilize the Continuing Fund for emergency PPW expenses.

Detailed Justification

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
System Support	**9,100**	**41,500**	**42,500**

This activity funds purchased power requirements that fulfill all 1200-hour contractual peaking power obligations with customers. In addition, energy purchases must be provided for replacement of transmission line losses associated with the delivery of non-Federal power over the Federal transmission system as required under Federal Energy Regulatory Commission (FERC) Order 888. Southwestern will continue to deliver limited peaking power and provide for power losses through power purchases. Southwestern will continue to use Federal power receipts and alternative financing methods, including net billing, bill crediting, and/or reimbursable authority (customer advances) to meet purchased power requirements.

System support requirements are affected by weather, volatile market prices, and limited availability of energy banks. For the past 20 years, Southwestern's purchased power requirements have been based on average water conditions, which were established in an effort to reduce unused appropriations during numerous good water years. Beginning in FY 2001, Southwestern received authority from Congress to use offsetting collections to fund power purchases, again based on average water conditions. However, during the FY 2005 and FY 2006 drought, funding problems developed resulting from the limited amount of offsetting collections authorized to fund PPW. Inadequate funding for PPW required constant requests to access the Continuing Fund in order to ensure sufficient funding was available to fulfill Southwestern's 1200-hour peaking power contractual obligations. Southwestern requested, and Congress approved, an increase in authority to use Federal power receipts (offsetting collections) in FY 2008. The use of this increased authority will be dependent upon the hydrological conditions of that fiscal year which, under average conditions, will be approximately half of the authority requested. Since the rates charged to its customers are based on costs, Southwestern has a built-in incentive to minimize its expenditures for purchased power. This increase in authority will ensure greater flexibility in times of below average generation and volatile market prices, and will decrease dependence on the Continuing Fund under all but the most severe hydrological conditions.

	FY 2007	FY 2008	FY 2009
Other Contractual Services	**3,300**	**3,500**	**3,500**

This activity funds other contractual services that provide for wheeling associated with the purchase of transmission service to meet limited peaking power obligations and for the integration of projects for the delivery of Federal power. The funding level for this activity is derived from contractual wheeling

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

requirements. Southwestern will continue to use Federal power receipts and alternative financing methods, including net billing, bill crediting, and/or reimbursable authority (customer advances) to meet wheeling requirements. The FY 2009 funding request reflects the projected cost for wheeling services based on contractual pricing and delivery terms.

Total, Purchase Power and Wheeling	**12,400**	**45,000**	**46,000**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
System Support	
▪ Increase in system support reflects anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions. The use of this increased authority will be dependent upon the hydrological conditions of that fiscal year which, under average conditions, will be approximately half of the authority requested.	+1,000
Total Funding Change, Purchase Power and Wheeling	**+1,000**

Program Direction

Funding Profile by Category

	(dollars in thousands/whole FTEs)		
	FY 2007	FY 2008 [a]	FY 2009
Program Direction (PD)			
Salaries and Benefits	17,150	18,140	19,659
Travel	665	700	847
Support Services	1,422	1,469	1,718
Other Related Expenses	1,545	1,745	2,106
Subtotal, Program Direction	20,782	22,054	24,330
Alternative Financing	n/a	-877	-2,200
Total, Program Direction	20,782	21,177	22,130
Full time Equivalents	169	179	179

Mission

The mission of the Program Direction subprogram is to assure continued reliability of the Federal power system by utilizing Federal staffing resources and associated funds required to provide overall direction and execution of Southwestern Power Administration's (Southwestern) Operation and Maintenance Program. This subprogram supports the 2005 Energy Policy Act (EPACT), the National Energy Policy (NEP), and the Department of Energy's (DOE) Strategic Plan by providing delivery of reliable, affordable, and environmentally sound energy to the Nation. This subprogram fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects Southwestern's program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

The Departmental Strategic Plan emphasized that DOE's Strategic Goals will be accomplished not only through the efforts of the major program offices in DOE, but also with additional effort from offices which support the programs in carrying out the mission. The Program Direction subprogram provides compensation and all related expenses for 179 Federal personnel, who market, deliver, operate, maintain and administer Southwestern's high-voltage interconnected power system and associated facilities. Southwestern will use appropriations and continue to use alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances) with customers and others who provide services or funds to assure a dependable and reliable Federal power system. Southwestern's authority to use net billing and bill crediting is inherent in the authority provided by the Flood Control Act of 1944, and has been affirmed by the Comptroller General.[b]

[a] Southwestern Power Administration's FY 2008 Current Appropriation reflects a 0.91% rescission in accordance with Public Law No. 110-161, Consolidated Appropriations Act, 2008, in the amount of $277,022 (Operations and Maintenance $86,204; Construction $30,947; and Program Direction $159,871).
[a] Honorable Secretary of the Interior B-125, 127 (February 14, 1956) available at WL 3064 (Comp. Gen.).

Southwestern performs critical functions in meeting the challenges of operating and maintaining the Federal power system to assure reliability, while meeting the growing demand for power and avoiding deterioration of the infrastructure. The functions include managing information technology, ensuring sound legal advice and fiscal stewardship, developing and implementing uniform program policy and procedures, maintaining and supporting our workforce, safeguarding our facilities, and providing Congressional and public liaison.

Southwestern is committed to performing its mission while supporting the initiatives of the President's Management Agenda. Southwestern assessed its performance in all five initiatives of the President's Management Agenda [Strategic Management of Human Capital, Expanded Electronic Government (E-Government), Competitive Sourcing, Improved Financial Performance, and Budget and Performance Integration] and is "Green" in all four relevant initiatives.

Southwestern's Program Direction subprogram further supports the Human Capital initiative, which is linked with careful planning and administration of the budget, through its Human Capital Management (HCM) Workforce Plan. This linkage is manifested in planning to assure that funds are available and allocated properly to support the initiative's elements. HCM Workforce Plan requirements include: reducing the number of organizational layers, addressing succession planning, reducing the time to make decisions, redirecting positions to the front lines, improving operational processes, and addressing other key workforce challenges.

By the end of FY 2009, approximately 30 percent of Southwestern's staff will be eligible for retirement. However, Southwestern will retain a strong staff of professionals dedicated to the pursuit of excellence by continuing to invest in its current employees, emphasize strong development programs, complete skills gap analyses, and pursue aggressive recruitment and retention efforts as identified in its HCM Workforce Plan.

Southwestern continues to share facilities and administrative services with another DOE office at Southwestern's Tulsa Headquarters facility. This arrangement is cost efficient and beneficial for both organizations.

Detailed Justification

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Salaries and Benefits	**17,150**	**18,140**	**19,659**

This activity funds salaries and benefits for 179 skilled Federal employees, who market and deliver Federal hydropower by operating and maintaining Southwestern's high-voltage interconnected power system with its associated facilities and providing support for these functions. The funding level for salaries is derived from the current year budgeted salaries plus cost-of-living adjustments, promotions, and within grade increases. The funding level for benefits is derived from a percentage of budgeted salaries. Annual benefit costs continue to increase faster than salaries due to rising health insurance premiums and the higher cost of an increasing number of FERS employees relative to CSRS employees.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

The FY 2009 level supports 179 FTE: 55 percent of the employees are General Schedule (GS) and subject to the Administration's proposed cost of living adjustment; salaries of the remaining 45 percent (craft workers and power system dispatchers) are determined through union negotiations and wage surveys. This activity also includes overtime, awards, relocation, workers' compensation, recruitment bonuses, retention pay, and advanced in-hire rates. The increase in funding is due to cost of living adjustments and significantly-rising benefit costs.

Travel	**665**	**700**	**847**

This activity funds all related travel and per diem expenses incurred in the operation and maintenance of Southwestern's geographically dispersed power system. The funding level for this activity is primarily derived from the daily requirement of the field maintenance personnel to maintain 1,380 miles of transmission line, 24[a] substations, 47 microwave/radio sites, communication equipment, and the Supervisory Control and Data Acquisition network.

This activity includes travel related to participation with the regional electric reliability council and Regional Transmission Organization to establish procedures for providing regional power restoration assistance to other non-hydropower generation sources during outage emergencies. Travel for E-Government-related initiatives and performance of general and administrative functions is also included. The increase in funding for this activity is due to rising per diem, transportation rates, and significantly increased fuel costs for mission-related travel to maintain the integrity and reliability of the integrated electrical grid.

Support Services	**1,422**	**1,469**	**1,718**

This activity funds contracted management support services including information technology, E-Government, and administrative/records management support. The funding level for this activity is derived from the most recent negotiated contract for support services essential to achieve Southwestern's mission. The increase in funding for this activity reflects the terms of the negotiated contract.

Other Related Expenses	**1,545**	**1,745**	**2,106**

This activity funds DOE's working capital distribution, rental space, printing and reproduction, training tuition, maintenance of office equipment, supplies and materials, employee parking, janitorial services, Equal Employment Opportunity investigations, Power Marketing Liaison Office (PMLO) services, financial audit, and A-123 requirements. Intermittent specialized services, not included in ongoing support service contracts, are also included. Rental space costs assume the GSA inflation factor. Other costs are based on the historical usage and actual cost of similar items. The increase in funding for this activity is primarily due to training, rental space, office equipment, financial audit, and working capital expenses.

Total, Program Direction	**20,782**	**22,054**	**24,330**

[a] This number will increase upon the transfer of generation substations to Southwestern.

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Salaries and Benefits	
▪ Increase in salaries and benefits reflects wage survey-based, union-negotiated, and Administratively Determined pay adjustments, and the Administration's proposed cost of living adjustment for GS employees. Payroll benefits are increasing at a rate in excess of salaries.	+1,519
Travel	
▪ Increase reflects rising per diem rates and significantly increased fuel costs for mission-related travel to maintain the transmission system.	+147
Support Services	
▪ Increase reflects funding for support services per the negotiated contract.	+249
Other Related Expenses	
▪ Increase in training	+81
▪ Increase in printing and reproduction	+10
▪ Increase in rental space costs due to the terms of the negotiated contract	+58
▪ Decrease in employee parking costs	-1
▪ Increase in financial audit per contractual terms	+14
▪ Increase in supplies and materials	+9
▪ Increase in working capital fund expenses	+88
▪ Increase in office equipment	+47
▪ Increase in other expenses	+55
Total, Other Related Expenses	+361
Total Funding Change, Program Direction	**+2,276**

Support Services by Category

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Management Support			
Reports and Analysis Management and General Administrative Services	1,422	1,469	1,718
Total, Management Support	1,422	1,469	1,718
Total, Support Services	1,422	1,469	1,718

Other Related Expenses by Category

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Other Related Expenses			
Training	54	97	178
Printing and Reproduction	41	39	49
Rent to Others	593	633	691
Employee Parking	103	84	83
Financial Audit	267	280	294
Power Marketing Liaison Office	140	140	140
Supplies and Materials	170	168	177
Working Capital Fund	0	0	88
Equipment	75	51	98
Other	102	253	308
Total, Other Related Expenses	1,545	1,745	2,106

Revenues and Receipts

(dollars in thousands)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Gross Revenues							
Sale and Transmission of Electric Energy	161,500 [a]	182,900	193,000	194,300	195,400	196,400	197,400
Total, Gross Revenues	161,500	182,900	193,000	194,300	195,400	196,400	197,400
Alternative Financing Credited as an Offsetting Receipt	-57,707	-64,100	-62,300	-62,500	-63,500	-64,600	-65,800
Revenue Accrual	-2,215	n/a	n/a	n/a	n/a	n/a	n/a
Offsetting Collections Realized, Purchase Power and Wheeling (PPW)[b]	-3,000	-35,000	-35,000	-37,000	-38,000	-39,000	-40,000
Total Proprietary Receipts	98,578	83,800	95,700	94,800	93,900	92,800	91,600
Percent of Sales to Preference Customers	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Energy Sales and Power Marketed (billion kilowatt hours)	5.4	5.4	5.4	5.4	5.4	5.4	5.4

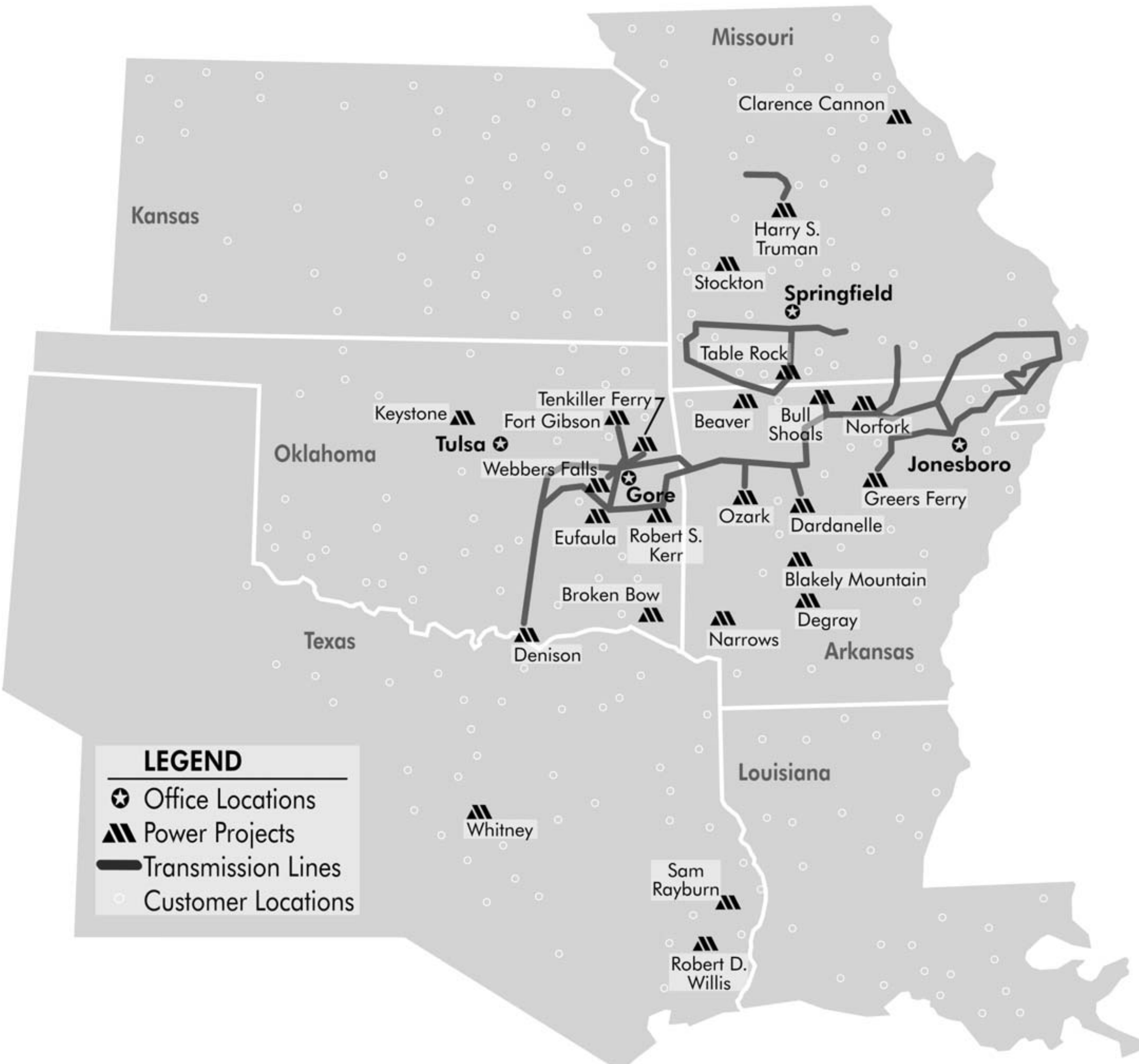
[a] Reflects an increase in revenues due to a rate increase to cover purchased power costs.
[b] Reflects an increase in use of receipts for purchase power and wheeling activities based on anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions.

System Statistics

	FY 2007 Actual	FY 2008 Estimate	FY 2009 Estimate	FY 2010 Estimate	FY 2011 Estimate	FY 2012 Estimate	FY 2013 Estimate
Generating Capacity (kilowatts)							
Installed Capacity	2,173,800	2,173,800	2,173,800	2,173,800	2,173,800	2,173,800	2,173,800
Peak Capacity	2,052,538	2,052,500	2,052,500	2,052,500	2,052,500	2,052,500	2,052,500
Generating Stations							
Generating Projects (Number)	24	24	24	24	24	24	24
Substations/Switchyards (Number)[a]	24	24	24	24	24	24	24
Substations/Switchyards (kVA Capacity)	1,026,900	1,026,900	1,026,900	1,026,900	1,026,900	1,026,900	1,026,900
Available Energy (Megawatt-hours)							
Energy Generated	5,677,327	5,454,100	5,440,200	5,438,100	5,411,200	5,411,200	5,411,200
Energy Received	109,137	183,000	187,400	188,200	209,400	209,400	209,400
Total, Energy Available for Marketing	5,786,464	5,637,100	5,627,600	5,626,300	5,620,600	5,620,600	5,620,600
Transmission Lines (Circuit-Miles)							
161-KV	1,117	1,117	1,117	1,117	1,117	1,117	1,117
138-KV	164	164	164	164	164	164	164
69-KV	99	99	99	99	99	99	99
Total, Transmission Lines	1,380	1,380	1,380	1,380	1,380	1,380	1,380

[a] This number will increase upon the transfer of generation substations to Southwestern.

System Map



Missouri
Clarence Cannon
Harry S. Truman
Stockton
Springfield
Table Rock
Kansas
Oklahoma
Keystone
Tulsa
Tenkiller Ferry
Fort Gibson
Webbers Falls
Gore
Beaver
Bull Shoals
Norfork
Jonesboro
Greers Ferry
Ozark
Dardanelle
Eufaula
Robert S. Kerr
Blakely Mountain
Degray
Broken Bow
Narrows
Arkansas
Texas
Denison
Louisiana
Whitney
Sam Rayburn
Robert D. Willis
LEGEND
Office Locations
Power Projects
Transmission Lines
Customer Locations

Power Marketed, Wheeled, or Exchanged By Project

	State	Number of Plants	Installed Capacity (kW)	FY 2007 Actual Energy (GWh)	FY 2008 Estimated Energy (GWh)	FY 2009 Estimated Energy (GWh)	FY 2010 Estimated Energy (GWh)	FY 2011 Estimated Energy (GWh)	FY 2012 Estimated Energy (GWh)	FY 2013 Estimated Energy (GWh)
Power Marketed										
Interconnected										
System	Missouri	4	463,200	1,738	1,672	1,668	1,668	1,666	1,666	1,666
	Arkansas	9	1,037,100	1,033	993	991	991	990	990	990
	Oklahoma	7	514,100	1,101	1,059	1,057	1,057	1,055	1,055	1,055
	Texas	2	100,000	826	794	793	793	792	792	792
	Louisiana	0	0	356	343	342	342	342	342	342
	Kansas	0	0	408	392	392	391	391	391	391
Subtotals		22	2,114,400	5,462	5,253	5,243	5,242	5,236	5,236	5,236
Isolated:										
Robert D. Willis Project										
Sam Rayburn Project										
50% to Texas		2	59,400	74	76	76	76	76	76	76
50% to Louisiana		0	0	74	76	76	76	76	76	76
Subtotals		2	59,400	148	152	152	152	152	152	152
Total, Power Marketed		24	2,173,800	5,610	5,405	5,395	5,394	5,388	5,388	5,388
Power Wheeled/Exchanged										
Wheeled (MW)				1,197	1,320	1,338	1,354	1,365	1,365	1,365
Exchanged (GWh)				2	0	0	0	0	0	0

Pending Litigation

Southwestern Power Administration (Southwestern) has no pending court litigation, as of January 9, 2008. Southwestern presently has the following administrative litigation pending before the Federal Energy Regulatory Commission (FERC):

On September 26, 2007, Southwestern filed revisions to its non-jurisdictional OATT to Incorporate the Large Generator Interconnection Procedures and Small Generator Interconnection Agreements into our tariff. On December 6, 2007, Southwestern filed an Attachment O-The Transmission Planning Process for its OATT tariff.

Southwestern is an intervener in the following actions pending before FERC:

P-459-128, Union Electric Ameren (UA). UA requested a license for a major project for the Osage project existing dam. Southwestern filed a Motion to Intervene on April 27, 2004.

RR06-1, North American Electric Reliability Council and North American Electric Reliability Corporation (NERC). NERC filed a request for certification as the Electric Reliability Organization. Southwestern filed a Motion to Intervene Out-of-Time to protect status interests as an owner of transmission facilities, substation facilities, and other facilities.

P-12470, Broken Bow. Southwestern intervened with comments on January 26, 2007.

OA08-05-000, Southwest Power Pool Compliance Filing Revising Order 890. Southwestern intervened on October 23, 2007.

OA08-61, Southwest Power Pool, Inc. Southwestern filed a Motion to Intervene on January 3, 2008.

ER08-340, Southwest Power Pool, Inc. Southwestern filed a Motion to Intervene on January 3, 2008.

Southwestern has one tort claim pending.

Southwestern has one EEO claim pending.

Southwestern management believes the possibility of incurring financially material liability in any of these matters is remote.

Western Area Power Administration

Western Area Power Administration

Construction, Rehabilitation, Operation and Maintenance
Western Area Power Administration

Proposed Appropriation Language

For carrying out the functions authorized by title III, section 302(a)(1)(E) of the Act of August 4, 1977 (42 U.S.C. 7152), and other related activities including conservation and renewable resources programs as authorized, including **[**the operation, maintenance, and purchase through transfer, exchange, or sale of one helicopter for replacement only, and **]**official reception and representation expenses in an amount not to exceed $1,500; **[**$231,030,000,**]***$193,346,000,* to remain available until expended, of which **[**$221,094,000**]***$183,642,000* shall be derived from the Department of the Interior Reclamation Fund: *Provided*, That of the amount herein appropriated, **[**$7,167,000**]***$7,342,000* is for deposit into the Utah Reclamation Mitigation and Conservation Account pursuant to title IV of the Reclamation Projects Authorization and Adjustment Act of 1992: *Provided further*, That notwithstanding the provision of 31 U.S.C. 3302, up to **[**$308,702,000**]***$328,118,000* collected by the Western Area Power Administration pursuant to the Flood Control Act of 1944 and the Reclamation Project Act of 1939 to recover purchase power and wheeling expenses shall be credited to this account as offsetting collections, to remain available until expended for the sole purpose of making purchase power and wheeling expenditures. (*Energy and Water Development and Related Agencies Appropriations Act, 2008.)*

Explanation of Change

The language excludes provision for the replacement of a helicopter authorized and initiated in FY 2008.

Falcon and Amistad Operating and Maintenance Fund

Proposed Appropriation Language

For operation, maintenance, and emergency costs for the hydroelectric facilities at the Falcon and Amistad Dams, **[**$2,500,000**]***$2,959,000*, to remain available until expended, and to be derived from the Falcon and Amistad Operating and Maintenance Fund of the Western Area Power Administration, as provided in section 423 of the Foreign Relations Authorization Act, Fiscal Years 1994 and 1995. *(Energy and Water Development and Related Agencies Appropriations Act, 2008.)*

Explanation of Change

No changes proposed for FY 2009.

Western Area Power Administration

Overview

Appropriation Summary by Program

(dollars in thousands)

	FY 2007 Current Appropriation	FY 2008 Original Appropriation	FY 2008 [a] Adjustments	FY 2008 Current Appropriation	FY 2009 Request
Western Area Power Administration Accounts					
Construction, Rehabilitation, Operation and Maintenance (CROM) Account Operating Expenses (Gross)	688,251	755,911	-2,123	753,788	826,634
Less Use of Alternative Financing [b]	-173,220	-212,242	0	-212,242	-301,804
Offsetting Collections from Colorado River Dam Fund (P.L. 98-381)	-3,705	-3,937	0	-3,937	-3,366
Offsetting Collections, Purchase Power and Wheeling (PPW) expenses	-279,000	-308,702	0	-308,702	-328,118
Total, CROM Account Budget Authority	232,326	231,030	-2,123	228,907	193,346
Total, Falcon and Amistad Operating and Maintenance Fund Budget Authority	2,665	2,500	-23	2,477	2,959
Colorado River Basins Power Marketing Fund (CRBPMF) Operating Expenses	186,221	232,145	0	232,145	240,284
Offsetting Collections Realized	-186,221	-255,145	0	-255,145	-263,284
Total, CRBPMF Budget Authority	0	-23,000	0	-23,000	-23,000
Total, Western Area Power Administration	234,991	210,530	-2,146	208,384	173,305

Preface

The Department of Energy (DOE) leads a critical effort to strengthen national and economic security, in promoting a diverse supply of reliable, affordable and environmentally-sound energy. Western Area Power Administration (Western), in conjunction with the U.S. Army Corps of Engineers (Corps), the U.S. Bureau of Reclamation (BOR) and the Department of State's International Boundary and Water Commission (IBWC), strongly supports this effort in managing the multipurpose operation of the Federal hydropower system to reliably deliver renewable energy across a high-voltage, integrated transmission system.

[a] FY 2008 reflects the 1.6 percent rescission of $48,000 to the CROM account for Congressionally directed funding, and the general 0.91 percent across-the-board rescission of $2,075,073 to other funds in the CROM account, and $22,750 to the Falcon and Amistad account (P.L. 110-161).

[b] FY 2007, FY 2008 Request, and FY 2009 CROM funding amounts include $148,931,000, $166,552,000, and $197,842,000 respectively, for planned alternative financing of the PPW subprogram; including use of Western's Continuing Fund as necessary to respond to below normal hydropower generation conditions. In addition, the FY 2007, FY 2008, and FY 2009 CROM funding amounts include $24,289,000, $45,690,000, and $103,962,000 respectively, for planned alternative financing of Western's Operation & Maintenance, Construction and Rehabilitation, and Program Direction subprograms.

Within the three appropriation accounts (e.g. Construction, Rehabilitation, Operation and Maintenance Account (CROM), the Falcon and Amistad Operating and Maintenance Fund, and the Colorado River Basins Power Marketing Fund (CRBPMF)), there is one program: the Western Area Power Administration. Within Western, there are a total of eight subprograms; five in the CROM Account, one in the Falcon and Amistad Operating and Maintenance Fund and two in CRBPMF.

Mission
Western markets and delivers reliable, cost-based Federal hydroelectric power and related services throughout the central and western United States.

Benefits
Western's marketing efforts and delivery capability span a 1.3-million-square-mile area serving a diverse group of approximately 750 wholesale customers, including municipalities, cooperatives, public utility and irrigation districts, Federal and State agencies and Native American tribes. In turn, wholesale power is used to provide service to millions of retail consumers.

Strategic Themes and Goals and GPRA Unit Program Goals
The Department's Strategic Plan identifies five Strategic Themes (one each for nuclear, energy, science, management, and environmental aspects of the mission) plus 16 Strategic Goals that tie to the Strategic Themes. Western's appropriations support the following goals:

Strategic Theme 1, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

Strategic Goal 1.3, Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

The Western program funded within the CROM Account, Falcon and Amistad Operating and Maintenance Fund, and CRBPMF has one GPRA Unit Program Goal that contributes to this strategic goal in the "goal cascade." This goal is:

GPRA Unit Program Goal 1.3.17: Market and reliably deliver Federal power to customers.

Contribution to Strategic Goal
Western, through its three accounts (CROM, Falcon and Amistad Operating and Maintenance Fund and CRBPMF), contributes to Strategic Goal 1.3, Energy Infrastructure, by performing its mission in a manner that promotes higher capacity U.S. energy infrastructure and ensures flexible reliable operations and efficient markets. Specifically, Western is incrementally improving its facilities to increase transmission capacity and enhance grid reliability to support continuing utility industry change, requests for interconnections to the Federal system, and evolving regional needs such as increased interest in renewable resources. Western also jointly plans, develops, and finances system enhancements, encouraging partnerships for transmission development and fostering cooperation and economic coordination among transmission partners.

Funding by Strategic and GPRA Unit Program Goal

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Strategic Goal 1.3, Energy Infrastructure			
GPRA Unit Program Goal 1.3.17, Western Area Power Administration Accounts			
Construction, Rehabilitation, Operation and Maintenance Account	688,251	753,788	826,634
Falcon and Amistad Operating and Maintenance Fund	2,665	2,477	2,959
Colorado River Basins Power Marketing Fund Operating Expenses	186,221	232,145	240,284
Total, Strategic Goal 1.3 (Western Area Power Administration Accounts)	877,137	988,410	1,069,877

Annual Performance Results and Targets

FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Targets	FY 2008 Targets	FY 2009 Targets
Strategic Goal 1.3, Energy Infrastructure					
Western Area Power Administration					
System Reliability Performance: The target is to attain monthly NERC compliance ratings of 100 or higher for Control Performance Standard (CPS) 1 and a rating of 90 or above for CPS2. (MET GOAL) Actual: CPS1:184.0 CPS2:98.3 Industry average: CPS1: 165.1 CPS2: 96.7	System Reliability Performance: Attain acceptable North American Electric Reliability Council (NERC) ratings for the following Control Performance Standards (CPS) measuring the balance between power generation and load: 1) CPS1 which measures generation/load balance and support system frequency on one minute intervals (rating>100); and 2) CPS2 which limits any imbalance magnitude to acceptable levels (rating>90). (MET GOAL) Actual: CPS1: 183.9 CPS2: 98.2 Industry average: CPS1: 161.4 CPS2: 95.9	System Reliability Performance: Attain acceptable North American Electric Reliability Council (NERC) ratings for the following Control Performance Standards (CPS) measuring the balance between power generation and load: 1) CPS1 which measures generation/load balance and support system frequency on one minute intervals (rating>100); and 2) CPS2 which limits any imbalance magnitude to acceptable levels (rating>90). (MET GOAL) Actual: CPS1: 184.4 CPS2: 98.7 Industry average: CPS1: 161.5 CPS2: 97.0	System Reliability Performance: Attain acceptable North American Electric Reliability Corporation (NERC) ratings for the following Control Performance Standards (CPS) measuring the balance between power generation and load: 1) CPS1 which measures generation/load balance and support system frequency on one minute intervals (rating>100); and 2) CPS2 which limits any imbalance magnitude to acceptable levels (rating>90). (MET GOAL) Actual: CPS1: 181.1 CPS2: 98.6	System Reliability Performance: Meet North American Electric Reliability Corporation (NERC) Control Performance Standards (CPS) of CPS1>100 and CPS2>90 and meet or exceed industry averages. CPS1 measures a generating system's performance at matching supply to changing demand requirements and supporting desired system frequency in one minute increments. CPS2 measures a generating system's performance at limiting the magnitude of generation and demand imbalances in ten minute increments.	System Reliability Performance: Meet North American Electric Reliability Corporation (NERC) Control Performance Standards (CPS) of CPS1>100 and CPS2>90 and meet or exceed industry averages. CPS1 measures a generating system's performance at matching supply to changing demand requirements and supporting desired system frequency in one minute increments. CPS2 measures a generating system's performance at limiting the magnitude of generation and demand imbalances in ten minute increments.
System Reliability Performance: Accountable customer and/or transmission element outages will not exceed the average number of outages for the past five years. (MET GOAL) Goal: <= 26 outages Actual: 21	System Reliability Performance: Accountable customer and/or transmission element outages will not exceed the average number of outages for the past five years. (MET GOAL) Goal: <= 23 outages Actual: 23		System Reliability Performance: Limit accountable customer and/or transmission element outages. (MET GOAL) Goal: <= 26 outages Actual: 18	System Reliability Performance: Accountable customer and/or transmission element outages will not exceed 26 for FY 2008.	System Reliability Performance: Accountable customer and/or transmission element outages will not exceed 26 for FY 2009.

FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Targets	FY 2008 Targets	FY 2009 Targets
	System Reliability Performance: Maintain ratio of unanticipated repair work hours to total maintenance hours at 16% or less. (MET GOAL) Actual: 7.1%				
Repayment of Federal Power Investment: Meet planned annual repayment of principal on Federal power investment. (MET GOAL) Goal: $31.9 M Actual: $93.6M					
	Repayment of Power Investment: Ensure unpaid investment is equal to or less than the allowable unpaid investment. Achieve a ratio of unpaid to allowable unpaid <= 1.00. (MET GOAL) Actual: 1.0		Repayment of Power Investment: Ensure unpaid investment is equal to or less than the allowable unpaid investment. Achieve a ratio of unpaid to allowable unpaid <= 1.00. (MET GOAL) Actual: <=1.0	Repayment of Investment Performance: Ensure unpaid investment (UI) is equal to or less than the allowable unpaid investment (AUI) in accordance with DOE Order RA 6120.2 and Reclamation Law. Achieve a ratio of unpaid to allowable unpaid <= 1.00.	Repayment of Investment Performance: Ensure unpaid investment (UI) is equal to or less than the allowable unpaid investment (AUI) in accordance with DOE Order RA 6120.2 and Reclamation Law. Achieve a ratio of unpaid to allowable unpaid <= 1.00.
Recordable Accident Frequency Rate: Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3, or the latest published Bureau of Labor Statistics' industry rate, whichever is lower. (MET GOAL) Actual: 1.6 Industry: 4.9	Recordable Accident Frequency Rate: Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3. (MET GOAL) Actual 1.6				

Means and Strategies

Western will use various means and strategies, outlined below, to achieve its GPRA Unit Program goal to ensure customers continue to receive maximum benefit from the Federal hydropower program. Various external factors are also shown which may impact Western's ability to achieve this goal. In addition, Western requires the collaborative support of its Federal hydropower partners to help achieve its goal.

Western will implement the following means:

- Improve the capability, performance and reliability of the integrated grid through technology and equipment enhancements.
- Improve workforce analytical capabilities and employee skills; hiring, training, and retaining a high-performing team to carryout the agency's mission.

Western will continue the following strategies:

- Ensure efficient transmission system operations to support the integrated nature of the Nation's power grid.
- Maintain and modernize systems and infrastructure to increase the reliability, efficiency, and use of Federal assets.
- Use sound business practices and prudent risk management in the conduct of agency activities and operations.

The following external factors could affect Western's ability to achieve its goal:

- System reliability can be affected by weather, natural disasters, changes in North American Electric Reliability Corporation (NERC) operation standards, industry deregulation, load growth, changing electric industry organizational structures, interconnections, open access and the lack of adequate funding resources.

Successful collaboration of the Federal hydropower partners is necessary for Western to achieve its goals. We coordinate our operational activities with the Corps, BOR, IBWC, customers, and regional utilities to provide the most efficient use of Federal assets and to ensure operational standards developed by NERC and regional reliability councils are met.

Validation and Verification

Annual performance goals for operational reliability are evaluated against NERC operating standards for the electric utility industry.

Western conducts various internal reviews and audits to validate and verify program performance. Western's program is also subject to continuing independent review by Congress, the Government Accountability Office (GAO), the DOE Office of Inspector General, FERC, the U.S. Environmental Protection Agency, Office of Personnel Management, NERC, and the regional reliability councils.

Program Assessment Rating Tool (PART)

The Department implemented a tool to evaluate selected programs. PART was developed by the Office of Management and Budget (OMB) to provide a standardized way to assess the effectiveness of the Federal Government's portfolio of programs. The structured framework of PART provides a means through which programs can assess their activities differently than through traditional reviews.

The current focus is to establish outcome- and output-oriented goals, the successful completion of which will lead to public benefits, such as increased national security and energy security, and improved environmental conditions. DOE has incorporated feedback from OMB into the FY 2009 Budget Request, and the Department will take the necessary steps to continue to improve performance.

In FY 2004, Western participated in a program assessment with OMB using PART. The resulting scores and findings were provided to Congress with the FY 2004 budget request. Western's scores equated to a "moderately effective" rating attributable to successful planning and management activities on capital investment to upgrade or expand existing infrastructure to promote reliable power delivery. However, these attributes were offset by OMB's contention that Western had neither adequate long-term goals, targets and measures; specifically efficiency measures, nor a unique role in industry and that Western competes with private industry. Subsequent changes in energy policy and proposed receipt financing of required annual expenses are removing program constraints which Western feels will allow it to operate in a "fully effective" and business-like manner. Western will continue to work closely with OMB to increase program efficiency as it pursues its statutory mandates with regard to marketing and delivery of Federal power to include customer preference, cost recovery, widespread use of power and revenue disposition.

Major Program Shifts and Changes

- The Administration supports reclassification of receipts from mandatory to discretionary (net zero appropriations) for the annual operating expenses of Southeastern, Southwestern, and Western Area Power Administrations (PMAs). Reclassification of receipts in this manner would allow the PMA programs to benefit from the alignment of PMA receipts with their annual (non-capital) expenditures provided by appropriations. This alignment would foster increased planning certainty for the PMA programs, which would ultimately improve the reliability and operating efficiency of the Federal power system. The Administration will continue to pursue reclassification of receipts through changes to the existing authorizing statute or by other means.

Construction, Rehabilitation, Operation and Maintenance
Western Area Power Administration

Funding by Site by Program

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Western Area Power Administration	688,251	753,788	826,634
Total, Construction, Rehabilitation, Operation and Maintenance	688,251	753,788	826,634

Site Description

Western's service area covers 1.3-million square-miles in 15 States. Western markets and delivers energy to about 750 wholesale power customers. These customers, in turn, provide retail electric service to millions of consumers in these central and western States: Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah and Wyoming.

Western annually markets and transmits about 10,000 megawatts of power from 56 hydropower plants and sells about 40 percent of regional hydroelectric generation. Western also markets the United States' entitlement from the coal-fired Navajo Generating Station near Page, Arizona.

Western operates and maintains an extensive and complex high-voltage transmission system to deliver power to its customers. Using its 17,005-circuit-mile Federal transmission system, Western will market and deliver reliable electric power to most of the western half of the United States.

The power facilities are made up of 14 multipurpose water resource projects and one transmission project. The systems include Western's transmission facilities and power generation facilities owned and operated primarily by the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers and the U.S. Section of the International Boundary and Water Commission.

Power sales, transmission operations and engineering services for Western's system are accomplished by its employees at 51 duty stations located throughout its service area. These include the Corporate Services Office in Lakewood, Colorado, and four customer service regional offices in Billings, Montana; Loveland, Colorado; Phoenix, Arizona; and Folsom, California. The Colorado River Storage Project Management Center in Salt Lake City, Utah, also provides customer support.

Falcon and Amistad Operating and Maintenance Fund
Western Area Power Administration

Funding by Site by Program

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Western Area Power Administration	2,665	2,477	2,959
Total, Falcon and Amistad Operating and Maintenance Fund	2,665	2,477	2,959

Site Description

The Falcon-Amistad Project consists of two international dams located on the Rio Grande River between Texas and Mexico. The United States and Mexico operate separate powerplants on each side of the Rio Grande River. The power output is divided evenly between the two Nations. The Department of State's International Boundary and Water Commission (IBWC) owns and operates the U.S. portion of the projects.

Falcon Dam is located about 130 miles upstream from Brownsville, Texas. The United States' portion of construction, operation and maintenance was authorized by Congress in 1950. Construction was started in that year and completed in 1954. The United States' share of Falcon Powerplant capacity is 31.5 megawatts (MW). The powerplant came on line in 1954.

Amistad Dam is located about 300 miles upstream from Falcon Dam. The Amistad Powerplant was constructed by the U.S. Army Corps of Engineers, as agent for the IBWC. The United States' portion of construction, operation and maintenance was authorized by the Mexican-American Treaty Act of 1950. Amistad Dam was completed in 1969. The United States' share of the two generating units, which came on line in 1983, is 66.0 MW.

Project power is marketed to a cooperative in south Texas via Central Power and Light Company's transmission system. There is no Federal transmission associated with these two projects.

Colorado River Basins Power Marketing Fund
Western Area Power Administration

Funding by Site by Program

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Western Area Power Administration	221,080	232,145	240,284
Total, Colorado River Basins Power Marketing Fund	221,080	232,145	240,284

Site Description

The Colorado River Basins Power Marketing Program is comprised of three power systems: the Colorado River Storage Project, including the Dolores and Seedskadee Projects; the Fort Peck Project; and the Colorado River Basin Project. Western Area Power Administration is responsible for construction, maintenance, and operation of facilities for transmitting and marketing the electrical energy generated in these power systems. A brief description of each follows:

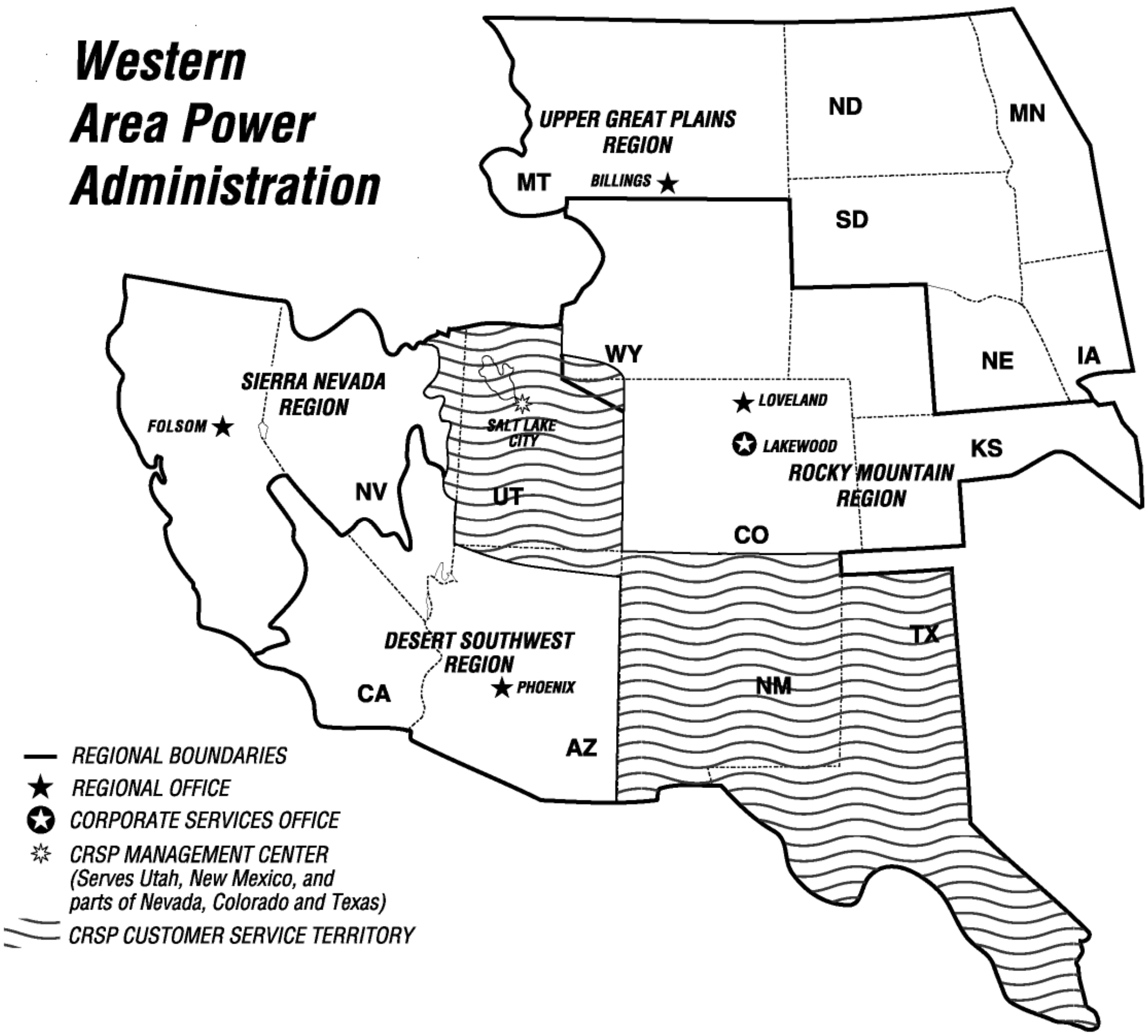
The **Colorado River Storage Project** (CRSP) was authorized in 1956. It consists of four major storage units: Glen Canyon, on the Colorado River in Arizona near the Utah border; Flaming Gorge on the Green River in Utah near the Wyoming border; Navajo on the San Juan River in northwestern New Mexico; and the Wayne N. Aspinall unit on the Gunnison River in west-central Colorado.

CRSP has a combined storage capacity that exceeds 33.5 million acre-feet. Five Federal powerplants associated with the project, with 16 generating units, have an operating capacity of 1,710 MW. CRSP provides for the electrical needs of more than a million people spread across Colorado, Utah, New Mexico and Arizona. Portions of Nevada and Wyoming are also served by CRSP power.

The **Dolores Project**, located in Montezuma and Dolores counties in southwestern Colorado, and the **Seedskadee Project**, located in southwestern Wyoming, were authorized as participating projects of CRSP. Dolores, a multipurpose project, provides 12.8 MW of installed power generating capacity along with municipal and industrial water, irrigation water, and recreation and fish and wildlife enhancement. The Dolores Project powerplants at McPhee Dam and the Towaoc Canal produce 1.3 and 11.5 MW, respectively. Seedskadee's power facilities, associated with the project's Fontenelle Dam, include an 11.5-MW powerplant, switchyard and necessary transmission lines to interconnect with the CRSP transmission system at Flaming Gorge Powerplant.

The **Fort Peck Project**, located on the Missouri River in northeastern Montana, was begun under an Executive Order in October 1933 as part of the Public Works Administration. The Fort Peck Project Act of 1938 authorized the completion, maintenance and operation of the project, and the Flood Control Act of 1944 authorized operational integration of the project with the Pick-Sloan Missouri Basin Program to serve a common market area. Installed generating capacity of the 5 units is 218 MW, which is delivered primarily to customers in eastern Montana and western North Dakota.

The Central Arizona Project (CAP) was authorized as an element of the **Colorado River Basin Project** to furnish irrigation and municipal water supplies to Arizona and New Mexico, and for other purposes. For financing, Western uses reimbursable arrangements to provide for its CAP expenses in lieu of revolving fund authorities.


Western
Area Power
Administration
UPPER GREAT PLAINS
REGION
BILLINGS
MT
ND
MN
SD
NE
IA
WY
SIERRA NEVADA
REGION
FOLSOM
SALT LAKE
CITY
LOVELAND
LAKEWOOD
ROCKY MOUNTAIN
REGION
KS
NV
UT
CO
DESERT SOUTHWEST
REGION
PHOENIX
CA
AZ
NM
TX
REGIONAL BOUNDARIES
REGIONAL OFFICE
CORPORATE SERVICES OFFICE
CRSP MANAGEMENT CENTER
(Serves Utah, New Mexico, and
parts of Nevada, Colorado and Texas)
CRSP CUSTOMER SERVICE TERRITORY

Construction, Rehabilitation, Operation and Maintenance

Funding Profile by Subprogram

(dollars in thousands)

	FY 2007 Current Appropriation	FY 2008 Original Appropriation	FY 2008 [a] Adjustments	FY 2008 Current Appropriation	FY 2009 Request
Construction, Rehabilitation, Operation and Maintenance Account (CROM)					
Operation and Maintenance (O&M)[b]	45,734	53,271	-398	52,873	52,365
Construction and Rehabilitation [c]	60,205	62,915	-496	62,419	74,544
Purchase Power and Wheeling (PPW)[d]	427,931	475,254	0	475,254	525,960
Program Direction [e]	147,748	157,304	-1,176	156,128	166,423
Utah Mitigation and Conservation	6,633	7,167	-53	7,114	7,342
Total, CROM (Operating Expenses)	688,251	755,911	-2,123	753,788	826,634
Use of Alternative Financing	-173,220	-212,242	0	-212,242	-301,804
Offsetting Collections–Colorado River Dam Fund (P.L. 98-381)	-3,705	-3,937	0	-3,937	-3,366
Offsetting Collections–PPW (P.L. 108-447, P.L. 109-103)	-279,000	-308,702	0	-308,702	-328,118
Total, CROM (Budget Authority)	232,326	231,030	-2,123	228,907	193,346

Public Law Authorizations:
Public Law 57-161, "The Reclamation Act of 1902"
Public Law 78-534, "Flood Control Act of 1944"
Public Law 95-91, "Department of Energy Organization Act" (1977)
Public Law 102-486, "Energy Policy Act of 1992"
Public Law 66-389, "Sundry Civil Appropriations Act" (1922)
Public Law 76-260, "Reclamation Project Act of 1939"
Public Law 80-790, "Emergency Fund Act of 1948"
Public Law 102-575, "Reclamation Projects Authorization and Adjustment Act of 1992"
"Economy Act" of 1932, as amended (41 stat. 613)

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[a] FY 2008 reflects the 1.6 percent rescission of $48,000 to the CROM account for Congressionally directed funding, and the general 0.91 percent across-the-board rescission of $2,075,073 to other funds in the CROM account (P.L. 110-161).
[b] O&M funding amounts include activities of the Boulder Canyon Project which are funded through Colorado River Dam Fund receipts via a reimbursable agreement with the Department of Interior as authorized in P.L. 98-381. By year, the amounts are $746,000, $929,000, and $803,000 for FY 2007, FY 2008, and FY 2009, respectively. Funding also includes use of alternative financing methods in the amount of $2,058,000, $5,000,000, and $15,499,000 for FY 2007, FY 2008, and FY 2009, respectively.
[c] Construction and Rehabilitation funding includes use of alternative financing methods in the amount of $17,177,000, $30,690,000, and $72,663,000 for FY 2007, FY 2008, and FY 2009, respectively.
[d] PPW program includes use of receipts from the recovery of PPW expenses of $279,000,000, $308,702,000, and $328,118,000 in FY 2007, FY 2008, and FY 2009 respectively. In addition, alternative financing methods are included in the amounts of $148,931,000, $166,552,000, and $197,842,000 for FY 2007, FY 2008, and FY 2009, respectively.
[e] Program Direction funding amounts include activities of the Boulder Canyon Project funded through the Colorado River Dam Fund via a reimbursable agreement in the amounts of $2,959,000, $3,008,000, and $2,563,000 for FY 2007, FY 2008, and FY 2009 respectively. Funding also includes use of alternative financing methods in the amount of $5,054,000, $10,000,000, and $15,800,000 for FY 2007, FY 2008, and FY 2009, respectively.

Public Law Authorizations:
"Interior Department Appropriation Act of 1928" (44 stat. 957)
Public Law 70-642, "Boulder Canyon Project Act" (1928)
Public Law 75-756, "Boulder Canyon Project Adjustment Act" (1940)
Public Law 98-381, "Hoover Power Plant Act of 1984"

Mission

Western markets and delivers reliable, cost-based Federal hydroelectric power and related services.

Operation and Maintenance
Funding Schedule by Activity

(dollars in thousands)

	FY 2007	FY 2008[a]	FY 2009
Operation and Maintenance [b]			
Regular Operation and Maintenance	24,472	25,138	29,166
Replacements and Additions	21,262	27,735	23,199
Total, Operation and Maintenance	45,734	52,873	52,365
Alternative Financing	-2,058	-5,000	-15,499
Use of Receipts from Colorado River Dam Fund	-746	-929	-803
Total, O&M Budget Authority	42,930	46,944	36,063

Description

The mission of Western's Operation and Maintenance (O&M) subprogram is to assure continued reliability of the Federal power system by operating and maintaining Western's transmission system at or above industry standards, including replacement of aging equipment and removal of constraints which would impede power flows.

Western's O&M subprogram supports DOE's Strategic Theme 1, Energy Security, by emphasizing replacement and upgrading of existing electrical system infrastructure to sustain reliable power delivery to our customers, to support a stable and reliable interconnected power system, to contain annual maintenance expenses, and to retain the value of its assets. Western ensures reliable electric power in a safe, cost-effective manner, and achieves continuity of service throughout its 15-State service territory by maintaining its power system at or above industry maintenance standards, rapidly restoring service following any system disturbance, mitigating adverse environmental impacts, performing clean-up activities, and maximizing revenues gained from non-firm energy and transmission sales.

Detailed Justification

Supplies and materials, such as wood poles, instrument transformers, meters and relays must be procured to provide the necessary resources to respond to routine and emergency situations in Western's high-voltage interconnected transmission system. Western implemented reliability-centered maintenance (RCM) scheduling to contain costs. RCM focuses on identifying critical components in a system and uses preventive and predictive maintenance practices to repair or replace equipment as needed. Technical services, such as waste management disposal, environmental impact analyses, and pest and weed control are used as needed.

[a] FY 2008 adjustment reflects the 0.91 percent general rescission of $398,122 (P.L. 110-161).
[b] Program descriptions and funding amounts include activities of the Boulder Canyon Project. These activities are funded through receipts from the Colorado River Dam Fund via a reimbursable agreement with the Department of Interior as authorized in P.L. 98-381.

Western's planned replacements and additions activity is based on an assessment of condition and criticality of equipment, maintenance/frequency of problems for individual items of equipment, availability of replacement parts, safety of the public and Western's personnel, environmental concerns, and an orderly work plan. The work plans, coordinated with Western's power customers, who ultimately bear the burden of all Western expenses, reflect an overall sustainable level of effort, with shifts in emphasis between categories (i.e., electrical versus communication equipment) in any given year.

Electrical equipment replacements, such as circuit breakers, transformers, insulators, revenue meters, switches, control boards, relays and oscillographs must be made to assure reliable service to Western's customers. System component age, availability of spare parts, environmental concerns, and risk to system reliability necessitate orderly replacement before significant problems develop.

Replacement, upgrade and installation of fiber optics, Supervisory Control and Data Acquisition (SCADA) systems, and other communication and control equipment continues to provide increased system reliability and to reduce maintenance and equipment costs.

Capitalized movable equipment, such as special purpose vehicles (e.g., cranes, auger trucks, manlifts), special purpose equipment (e.g., pole trailers, industrial tractors, brush chippers), specialized test equipment (e.g., motion analyzers and relay test equipment), computer-aided engineering equipment, office equipment, and IT equipment and software, must be upgraded and replaced.

Personnel expenses and personnel performance accomplishments associated with the O&M subprogram are combined with those of the Construction and Rehabilitation subprogram and are reflected in the Program Direction subprogram of Western's budget request.

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Regular Operation and Maintenance	**24,472**	**25,138**	**29,166**

Supplies and materials necessary to respond to routine and emergency situations in Western's high-voltage interconnected transmission system will be purchased. This includes miscellaneous equipment, and software used for power billing, transmission planning, e-tagging, and energy scheduling, as well as supplies and materials such as wood poles (individual pole replacement; excludes whole line replacements), instrument transformers, meters, relays, etc. necessary to respond to routine and emergency situations in Western's high-voltage interconnected transmission system. The request includes $743 thousand for activities in the Boulder Canyon Project, funded directly through receipts from the Colorado River Dam Fund.

The continuing maintenance of Western's transmission system at or above industry standards supports DOE's Strategic Theme 1 by minimizing sudden failure, unplanned outages, and possible regional power system disruptions. Safe working procedures are discussed before work begins to optimize safety for the public, Western's staff, and equipment. The request is based on projected work plans for activities funded from this account. Estimates are based on historical data of actual supplies needed to operate and maintain the transmission system and recent procurement of similar items.

	FY 2007	FY 2008	FY 2009
	(dollars in thousands)		
Replacements and Additions	**21,262**	**27,735**	**23,199**

Western's planned replacements and additions activity is based on an assessment of condition and criticality of equipment, maintenance/frequency of problems on individual items of equipment, availability of replacement parts, safety of the public and Western's personnel, environmental concerns, and an orderly work plan. Replacement of aged power system components maximizes the reliability and availability of Western's system by reducing the risk of equipment failure, unplanned outages, and possible regional power system disruptions. Removing environmental hazards and replacement of aged equipment eliminates safety hazards for the public and Western's personnel. Planned activity is detailed by category below.

	FY 2007	FY 2008	FY 2009
▪ **Electrical Equipment**	**10,392**	**12,673**	**9,334**

Electrical equipment, such as circuit breakers, transformers, relays, batteries and chargers, reactors, meters, buses, surge arresters, capacitor banks and disconnect switches, will replace obsolete equipment at facilities throughout Western's 15-State area. Also included is test equipment used by maintenance crews, such as metering and relaying test sets, pentameters, Ohm testers, oil dielectric testers, battery load testers, and specialized communication and environmental control test equipment. Replacement and rehabilitation of single wood pole structures, overhead ground wires, and line hardware will extend the life of aging, deteriorating transmission lines. This request includes $60 thousand for the Boulder Canyon Project portion of this activity.

Estimates are based on analysis of system operation/maintenance requirements and concerns, customer-coordinated work plans, actual costs of recent similar projects, and bottom-up budgeting techniques.

	FY 2007	FY 2008	FY 2009
▪ **Communications Equipment**	**2,515**	**5,626**	**3,943**

Western will continue to maintain system reliability by replacing remote terminal units, telephone systems, microwave links, and aged 7 Ghz analog radio systems with digital ratio and fiber optics. The staged movement to narrow communications band spectrums for UHF radios as directed by the National Telecommunications and Information Administration (NTIA) continues. Western's communication systems are currently made up of approximately 7 percent fiber optics, 81 percent fixed radio, and 12 percent mobile radio. Western currently has 1,381 radio frequency authorizations for fixed radio bands, of which 586, or 42 percent, are analog. The funding requested here will not be used to replace equipment impacted by the Spectrum Relocation initiative.

In addition, Western will continue upgrades to its existing SCADA systems which control Western's electric power system. These hardware and software upgrades improve grid reliability by allowing the main computer to communicate with remote terminal units in the 296 substations across Western's territory, thus allowing the dispatcher to operate a device in any of these substations to make changes rapidly to respond to power industry requirements or system emergencies. Also included in this estimate are upgrades to Western's Merchant Alternate Control Center.

Costs are based on analysis of system operation/maintenance requirements, customer-coordinated work plans, actual costs of recent similar projects, and bottom-up budgeting techniques.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
▪ **Spectrum Relocation Equipment**	**0**	**0**	**0**

In December 2004, the Congress passed and the President signed the Commercial Spectrum Enhancement Act (CSEA, Title II of P.L. 108-494), creating the Spectrum Relocation Fund (SRF) to streamline the relocation of Federal systems from certain spectrum bands to accommodate commercial use by facilitating reimbursement to affected agencies of relocation costs. The Federal Communications Commission has allocated this spectrum for Advanced Wireless Services. Funds have been made available to agencies from the crediting of auction receipts to the SRF during fiscal year 2007 and system relocation efforts have commenced. The amount received by Western for this effort is $108 million and includes Western's estimated relocation costs, as approved by the Office of Management and Budget, and as reported to the Congress by the Department of Commerce in December 2005. Since receipt of these funds, Western has completed much of the preliminary design work to include radio path analysis, identifying towers for load analysis, identifying communications buildings for upgrades or replacements, submitting radio frequency authorization requests, and preparing the necessary documentation for radio and other communication equipment purchases. Structural loading analyses for both radio and fiber optic systems is planned to occur during the first half of FY 2008, as is the building specification process. Radio orders will be placed once frequencies are received from NTIA. FY 2007 has been a planning and design year. The first construction year for the Spectrum Relocation Fund is anticipated to begin during FY 2008 with the installation of antennas and waveguides, building replacements, and installation of radios upon receipt of equipment. The phased replacement of 2 GHz radio systems is anticipated to continue into FY 2010. The funding for the Spectrum Fund is mandatory and will remain available until expended, and agencies will return to the SRF any amounts received in excess of actual relocation costs. No appropriations are being requested for this activity.

▪ **Capitalized Movable Equipment**	**8,355**	**9,436**	**9,922**

These funds will purchase special purpose line trucks and specialized trailers. Western's first choice of vehicle coverage is a GSA lease, when such vehicles are available. However, GSA cannot always accommodate our needs, especially in the Upper Great Plains Region and somewhat in the Desert Southwest Region, where vehicles must be equipped for extreme weather conditions that exist. At those times, it is necessary to purchase such vehicles, and this request is representative of that condition. All sedans, vans, SUVs, and light trucks are GSA-leased. Western uses 733 vehicles, 429 (59 percent) of which are leased from GSA. Replacement of government-owned vehicles is based on the Federal Management Regulations guidelines, the same guidelines used by GSA. Specialized equipment such as man lifts, snow cats, forklifts, cranes, front-end loaders, and caterpillars are also included.

Other capitalized movable equipment in this estimate that are needed to support the O&M of the interconnected power system include substation test equipment, brush chipper, map board replacement; security equipment such as perimeter intrusion detection devices, card readers and associated software, security cameras and recording devices at various sites throughout Western; Information Technology equipment such as server and router replacements, firewalls, cyber security upgrades, LAN upgrades, network equipment replacements, replacement of Western's tape backup library, Enterprise application upgrade for Western's maintenance management system (Maximo),

	(dollars in thousands)	
FY 2007	FY 2008	FY 2009

computer-aided design equipment (CAD) used for engineering-specific applications and drawing archives; global information system hardware upgrades; replacement of equipment for the MiniPower Simulator at Western's Electric Power Training Center to accommodate changes in technology; and helicopter equipment replacements that add value to the helicopter or extend the service life, such as engine, rotor blades, avionics, airframe, and other major components.

Replacement needs are based on age, reliability, and safety of equipment, customer-coordinated review, cost analysis of rebuild versus replacement, availability of replacement parts, and obsolescence of diagnostic maintenance tools. Estimates are determined using actual costs of similar items.

	FY 2007	FY 2008	FY 2009
Total, Operation and Maintenance	**45,734**	**52,873**	**52,365**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Regular Operation and Maintenance	
▪ The overall net increase in regular O&M is attributed to inflation and increased cyclical maintenance activity to Western's transmission system which include wood pole replacements and miscellaneous equipment.	+4,028
Replacements and Additions	
▪ The decrease in replacements and additions of electrical equipment (-$3.3 million) results from a decrease to the purchase of specialized test equipment, a decrease in the steel pole replacement program (using in-house labor instead of contractual), decrease in reactor cap bank replacements, and fewer requirements for major breaker replacements. The decrease in communications equipment (-$1.7 million) is primarily caused by the cyclical decrease in system upgrade purchases to one of Western's communication systems, which is now in a maintenance cycle. The increase in capitalized movable equipment is attributable to an increase in special vehicle purchases (+$0.5 million).	-4,536
Total Funding Change, Operation and Maintenance	**-508**

Construction and Rehabilitation
Funding Schedule by Activity

	(dollars in thousands)		
	FY 2007	FY 2008 [a]	FY 2009
Construction and Rehabilitation			
Transmission Lines and Terminal Facilities	33,023	26,778	26,176
Substations	22,122	30,270	40,522
Other [b]	5,060	5,371	7,846
Subtotal, Construction & Rehabilitation	60,205	62,419	74,544
Alternative Financing	-17,177	-30,690	-72,663
Total, Construction & Rehabilitation (Budget Authority)	43,028	31,729	1,881

Description

The mission of Western's Construction and Rehabilitation (C&R) subprogram is to assure continued reliability of the Federal power system by modification, replacement, additions, and interconnections to the Federal power system.

Western's C&R subprogram supports DOE's Strategic Theme 1, Energy Security, by emphasizing replacement and upgrading of existing electrical system infrastructure to sustain reliable power delivery to our customers, to support a stable and reliable interconnected power system, to contain annual maintenance expenses, and to retain the value of its assets. Replacement and upgrade of aged power system components are crucial to system reliability, and communications improvements maintain vital control over system operations. Both contribute to attaining or exceeding monthly control performance standards established by the North American Electric Reliability Corporation (NERC) by reducing the risk of equipment failure, unplanned outages, and possible local and regional power system disruptions. C&R subprogram activities support the repayment of Federal power investment by promoting a well-planned C&R program with a relatively stable budget over the long term, by avoiding significant additional costs of emergency "breakdown maintenance," and by preventing outages which could impact power deliveries, purchase power costs, and power revenues. Reducing the hazards associated with worn or aging equipment, correcting design deficiencies, and replacing deteriorated wood poles which present a serious climbing hazard to linemen, minimizes Western's exposure to unsafe conditions. In addition, public safety is protected by avoiding or minimizing the negative impacts of unplanned outages and by minimizing the instances of downed lines.

The C&R request incorporates the most current information to identify and schedule necessary C&R projects. Western assigns the highest program priority to those situations that pose the highest risk to safety and system reliability, while meeting the mandates for open access to our transmission system. If

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[a] FY 2008 is adjusted $48,000 to reflect the 1.6 percent rescission for Congressionally directed funding, and $447,775 to reflect the 0.91 percent general rescission for other funding.
[b] Other includes communication equipment, maintenance facilities, power facility developmental costs, and minor unscheduled jobs.

conditions change, Western will shift funding as necessary to ensure the highest program priorities continue to be met to maintain the reliability and integrity of Western's power transmission system.

Western's transmission system has 17,008 circuit-miles of line and 296 substations. Of the 8,018 miles of wood poles, 6,258, or 78 percent, exceed the normal service life of 40 years, with 4,785, or 60 percent, exceeding 50 years. Western is continually testing, treating, and replacing individual wood poles and hardware to delay the need for replacing an entire transmission line. As substation equipment (such as power transformers, circuit breakers, and control equipment) ages, maintenance costs increase, replacement parts become unavailable, risk of outages increase, and system reliability declines. Western has 72 transformers and 86 circuit breakers more than 40 years old. The normal service life for power transformers and power circuit breakers is 40 years and 35 years, respectively. While replacement of this equipment is systematically planned over 10 years, actual replacement varies depending on condition and criticality. All replacement and rehabilitation plans are coordinated with customers to help establish the timing and scope of work at specific substations. When upgrades or additional capacity are required, Western actively pursues opportunities to partner with neighboring utilities to jointly finance activities, which result in realized cost savings and increased efficiencies for all participants.

Western's FY 2009 and outyear C&R request is above prior year levels because of the aging power system infrastructure, backlog of rehabilitation needs, increasing industry requirements (FERC, NERC, WECC), and greater reliability concerns resulting from increasing loads and the need for integrating new generation sources to meet those loads.

Personnel costs and related expenses for the workforce to plan, collect field data, write specifications, design facilities, award construction contracts, and purchase government-furnished equipment for the C&R activity are combined with those of the O&M activity and are reflected in the Program Direction section of Western's budget request.

For purposes of budget display, the C&R subprogram is broken into three activities: Transmission Lines and Terminal Facilities, Substations, and Other. The Other category includes communications equipment (microwave, fiber optic, and telecommunications), maintenance facilities, power facility development costs, and minor unscheduled jobs. Planned activity is detailed by category below.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Transmission Lines and Terminal Facilities	**33,023**	**26,778**	**26,176**
▪ **Transmission Lines and Terminal Facilities, Continuing Work**	**32,897**	**24,678**	**17,826**

Continuation of modifications and rehabilitation of the following transmission lines (TL) to ensure power system reliability and stability is planned in FY 2009.

- Replace existing Watford City-Williston (North Dakota) 115-kV transmission line with 230-kV transmission line. This 42-mile transmission line has been in service since 1951. The majority of the structures do not meet Western's design criteria. The upgrade of the line will provide additional transfer capability which will alleviate existing reliability criteria violations during system outages.
- Rebuild 9.8 miles of existing Gila-Yuma Mesa Tap (Arizona) 34.5-kV transmission line using existing right of way where feasible. Built in 1943, the wood poles are in need of replacement. Due to the deteriorating condition of these structures, a failure is possible that could result in service interruption, property damage, and injury to the general public or Western's personnel. The existing line was constructed without an overhead ground wire to protect against lightning strikes. Replacement of the existing wood pole line with steel poles and overhead ground wire will increase the safety and reliability of the system.
- Rebuild the 35-mile Ault-Cheyenne 115-kV transmission line (Colorado and Wyoming). The line was constructed in 1939 using wood pole H-frame structures and 250,000 circular mil Anaconda copper conductor. The line is over 60 years old and in need of conductor and hardware replacement. To be spliced, the copper conductor requires special equipment and expertise, and replacement hardware is becoming difficult to find. Most of the poles have extreme shell rot and are unsafe to climb; line work must be done under clearance using a bucket truck. Rebuilding the line is necessary to mitigate the reliability and safety concerns.
- Construction of Trinity-Weaverville transmission line (California) consisting of approximately 9 miles of new 60-kV line from Lewiston to Weaverville and 7 miles of 60-kV line rebuilt from the Trinity Power Plant to Lewiston, with a terminal facility near Weaverville. Consumers in this area routinely have outages, many of which last three to four days in the winter before power can be restored. This project will enhance the reliability of service to Trinity County consumers and fulfill the obligation established by the Trinity Division Act of August 12, 1955, to construct, operate and maintain transmission facilities as may be required to deliver the output of power plants to loads in the County.

The funding level is determined by estimating the cost to complete each project and breaking out these costs by fiscal year. The estimates are based on recent actual costs to complete similar projects, updated individual project requirements, and past experience.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
▪ **Transmission Lines and Terminal Facilities, Rehabilitation Starts**	**126**	**2,100**	**8,350**

The following transmission line and terminal facility rehabilitation starts are planned in FY 2009. Transmission line and terminal facility starts address specific system reliability risks or operational problems.

- Replace 52 temporary wood structures along an 8-mile section of the Oahe-Glenham 230kV transmission line (South Dakota) with 31 single pole steel structures, and replace 5 damaged steel lattice towers that remain in service. The replacements are necessary to remove the liability concerns associated with the temporary structures and the 5 damaged steel lattice towers. In FY 2005, high winds caused severe damage to thirty-six lattice steel structures. The temporary wood structures were installed following the wind storm to quickly bring the transmission line back into service.
- Rebuild the 46-mile Erie-Hoyt 115-kV transmission line (Colorado) with a 115/230-kV single pole double circuit line. The existing line was placed in service in 1952 and is approaching its maximum service age. Rebuild is necessary to improve system reliability and minimize maintenance costs. The 115-kV circuit will be capable of operating at 230-kV providing for future growth and additional capacity for potential wind generation projects. Customer participation in the rebuild will provide for the second 230-kV circuit.
- Reconductor the 9-mile Shasta-Flannigan-Keswick 230-kV transmission line (California) to relieve current congestion for generation from the Shasta Powerplant by upgrading the line to a higher capacity conductor. Reconductoring the 40 year old line will increase capacity by 40 MW; improving transfer capability to Central Valley Project customers and improving system reliability.
- Upgrade the 500-kV California-Oregon Intertie (COI) to increase transfer capabilities across the California-Oregon border. The upgrade will increase the north-to-south COI rating by 300 MW, from 4800 MW to 5100 MW, allowing for greater import of energy, either renewable or non-renewable, from the Pacific-Northwest into California.

Estimates are based on actual costs of recent similar projects, expected costs of needed equipment and services, cost estimating guides, and experience.

▪ **Transmission Lines and Terminal Facilities, Work Funded by Others**	**0**	**0**	**0**

Western's work for others has increased significantly under the open access transmission tariff adopted in response to FERC Order No. 888. The tariff requires Western to provide interconnections to its transmission system. New generation projects typically surface quickly and provide little advance warning for internal planning and budgeting. Western must work with requestors to meet their needs.

Design of these facilities must be closely coordinated with, or accomplished by, Western's design staff to ensure compatibility with Western's equipment and facilities and compliance with applicable electrical and safety codes. These projects also affect transmission system loading and operation. Potential impacts to other system facilities and equipment must be determined since the cost of any necessary modifications must be borne by the interconnection project proponents.

(dollars in thousands)

Potential transmission line and terminal reimbursable work in FY 2009 includes, but is not limited to, planning, design or construction of:

- Havre-Rainbow 230-kV TL Rebuild with new overhead ground wire and conductors due to generation additions request (Montana).
- Replacement of transmission lines from Wellton Mohawk Irrigation and Drainage District's Ligurta substation to their #1 and #3 pumping plants (Arizona).
- O'Banion-Elverta Double Circuit 230-kV line for Sacramento Municipal Utility District and the City of Roseville (California).
- Interconnection for Contra Costa Water District's Alternative Intake Project (California).
- Eastern Plains Transmission Project and Erie-Hoyt transmission line upgrade for Tri-State Generation and Transmission Association (Colorado).

	FY 2007	FY 2008	FY 2009
Substations	**22,122**	**30,270**	**40,522**
▪ **Substations, Continuing Work**	**7,524**	**15,450**	**21,394**

Continue modifications and rehabilitation of the following substations in FY 2009 to ensure power system reliability and stability. The funding level is determined by estimating the cost to complete each project and breaking out these costs by fiscal year. The estimates are based on recent actual costs to complete similar projects, updated individual project requirements, and past experience.

- Replace the Brookings Substation (South Dakota) 115/69, 18.75 MVA KY1A transformer with a 50 MVA unit and replace associated electromechanical relays and protection schemes. Transformer KY1A, installed in 1954, has exceeded its life expectancy and should be replaced before catastrophic failure causes degradation to the power system and customer outages. The existing 115-kV main and transfer bus will be converted to a breaker and a half scheme. The city of Brookings has two lines at 115-kV serving their loads. Because of the existing bus design, both lines are lost in the event of a bus differential trip. Converting to a breaker and a half design will mitigate this situation.
- Upgrade of ED5 Tap Substation (Arizona) with a new five circuit breaker ring bus to replace the existing tap. Constructed in 1952, the existing motor-operated disconnects have not been upgraded, are deteriorating, and are a reliability concern. They are not capable of interrupting load or fault current, making maintenance difficult and costly. Spare parts are obsolete and difficult to replace.
- Replacement of old and failing equipment at Gila Substation (Arizona). This 34.5-kV yard was placed in service in 1945 as part of the Parker Dam Project. The circuit breakers and switches are obsolete with no replacement parts available. Failure of this equipment prevents Western

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

from serving its customer loads and meeting contractual obligations. The project will replace six 34.5-kV circuit breakers and 18 disconnect switches, as well as reconfigure the station service transformer feed.

- Replacement of 161-kV oil breakers at Parker Substation (California). Nine of the 161-kV breakers are of the mid-1970's vintage and are oil filled. This project will improve the system reliability, reduce outage times taken for maintenance, reduce operating costs, and eliminate environmental hazards.
- Construct a 230-kV addition to the Beaver Creek Substation (Colorado) constructed in 1952. The addition is part of a joint improvement project to provide for improved reliability and voltage support to northern Colorado loads. The additions are necessary to fully utilize the 230-kV joint upgrades to the Beaver Creek-Hoyt and Erie-Hoyt transmission lines.
- Upgrade Tracy 230-kV Substation (California) to a double-breaker, double-bus configuration by adding breakers, disconnects, bus, and associated control, protection and communication equipment. The upgrade is necessary to meet operational reliability requirements for this very critical substation that serves central California and the San Francisco Bay Area. The current substation design is a main and transfer bus configuration which can lead to loss of up to six critical 230-kV transmission lines, two major ties to the Tracy 500-kV Substation, and the entire Tracy pumping plant if breaker failure happens due to human error or failure of breaker protection equipment. This would represent a loss of 2,150 MVA of transfer capacity, potentially causing a major West Coast power outage during critical load times of the year.
- Construct a new 500-kV O'Banion Substation (California) with 500/230-kV transformation. Loop the existing PG&E's Table Mountain – Tesla 500-kV line into the new 500-kV yard. Add breaker bay and associated protection and control circuits to the existing O'Banion 230-kV yard as required. The project will improve the reliability of the CVP transmission system, conform to NERC/WECC reliability criteria, meet Western's transmission service obligations, and inhibit uncontrolled system-wide outages and loss of load which will have a definite impact on local and regional system/economy.

▪ **Substations, Rehabilitation Starts**	**14,598**	**14,820**	**19,128**

The following substation rehabilitation starts are planned in FY 2009:

- Replace the Creston 161/69-kV, 50 MVA, KY1A transformer (Iowa) and associated control and protection equipment which require excessive maintenance and may contain PCB contaminated capacitors. The transformer and associated control and protection equipment were installed in 1963 and have exceeded their expected service lives. System studies warrant replacement at 100 MVA to improve system reliability.
- Addition of 230-kV bay in the main and transfer bus of the Granite Falls Substation (Minnesota) to provide outlet for 600 MW customer-owned powerplant under construction in the vicinity of the Granite Falls substation.
- Replace the Sioux City 161/69-kV, 75 MVA, KY3A transformer (Iowa). The transformer was installed in 1962 and has exceeded its expected service life. System studies warrant replacement

at 100 MVA to improve system reliability.

- Replace the Sioux Falls (South Dakota) transformers KV3A (230/115 33.3 MVA) and KV5A (230/115 33.3 MVA) with 250 MVA 3-phase autotransformers to improve system reliability. System studies identify capacity deficiencies in the existing transformers as a result of significant commercial and residential load growth.

- Upgrade Utica Junction 230-kV Switching Station (South Dakota) to interconnect with customer's 115-kV system at Utica Junction to mitigate low voltage issues in the area. The project consists of converting the switching station to a 230-kV 4-breaker ring bus for termination of three 230-kV transmission lines, installation of a 230/115-kV transformer, and construction of a 115-kV 3-breaker ring bus.

- Replace the Forman Substation 115/69-kV, 20 MVA, KY1A transformer (North Dakota). The transformer was installed originally in Valley Substation in 1952, and moved to Forman Substation in 1971. The transformer has far exceeded its expected service life of 40 years. System studies have identified capacity deficiencies in the transformer and warrant replacement at 40 MVA to improve system reliability.

- Addition of 115-kV bus to Rolla Substation (North Dakota), currently 69/41.8/12.5-kV, to improve voltage support and increased reliability in the area. Western's 69/41.8-kV equipment at the substation was installed in 1952 and is in need of replacement. Western plans to install the 115-kV bus upgrade and anticipates customers will provide for lower voltage equipment.

- Replace Valley City Substation (North Dakota) 115/69-kV 50 MVA KY1A transformer and associated control equipment. The transformer and most of the control equipment, installed in 1952, have exceeded their useful lives. The transformer is leaking and the control equipment requires extensive maintenance. Systems studies have identified capacity deficiencies; replacement of the transformer with a 70 MVA unit is warranted to address reliability requirements.

- Upgrade of Havre Substation (Montana) bus to provide ring bus scheme to enhance reliability, the addition of a 115-kV bay and capacitor banks to address current low voltage issues, and replacement of control building and boards installed in 1951 that exceed their respective service lives and require extensive maintenance.

- Rebuild Bouse Tap (Arizona) as a three breaker ring bus to improve system reliability by restoring remote operating and emergency line-break capability to this segment of the Parker-Gila 161-kV transmission line. The existing switchyard, constructed in the early 1950's, has exceeded its useful life and can no longer support remote operations. Customer participation in funding is anticipated to cover more than a quarter of the project's costs.

- Rebuild aging Davis Switchyards (Arizona) built in the late 1940s to provide increased reliability. The bulk of the equipment in the yards is operating beyond their useful service lives. Problems include failing circuit breakers, unreliable regulating transformer, broken disconnects, oil leaks, and abandoned equipment. The rebuild will provide a more effective bus arrangement, replace oil-filled circuit breakers with SF6 gas breakers to eliminate over 140,000 gallons of oil

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

from the site adjacent to the Colorado River, and construct a control building to house the relays, control equipment, and battery systems.

- Reconfiguration of the 40 year old Folsom Substation (California) to improve the reliability of the Central Valley Project transmission system and conform with FERC Orders and NERC reliability criteria. The reconfiguration is particularly critical to the transmission network in the greater Sacramento area which continues to be stressed during peak load periods. The current main and transfer bus configuration could lead to loss of three critical 230-kV connections if there's a failure at the substation leading to potential loss of power to the entire Sacramento area. Reconfiguration of the substation will include nine 230-kV breakers and new control, protection, and communication equipment. The existing Elverta-Roseville 230-kV transmission lines and three power plant feeds will move to the reconfigured substation.
- Rebuild the 40 year old O'Neill Substation (California) to improve the reliability of the electrical supply facilities for the O'Neil pump/generating station. The substation is the sole source of power to six large pump/generation units operated by the U.S. Bureau of Reclamation as part of the San Luis Water Project.
- Construction of a new switching station near Elliot (North Dakota) to improve reliability as a result of load growth in this area. The Elliot Switching Station will consist of a 115-kV ring bus with three 115-kV transmission lines terminating at this location.
- Replacement and upgrade of equipment at Morris Substation (Minnesota) to accommodate new generation from customer construction of a 600 MW power plant in the vicinity of the Morris substation. The project includes addition of a 230-kV bay, and replacement of an existing 230/115-kV 100 MVA transformer with a 300 MVA unit to avoid overloads.

The funding level is determined by estimating the cost to complete each project and breaking out these costs by fiscal year. The estimates are based on recent actual costs to complete similar projects, updated individual project requirements, and past experience.

▪ **Substations, Work Funded by Others**	**0**	**0**	**0**

Substation reimbursable work in FY 2009 includes:

- Havre Substation 230-kV Bay Addition (Montana).
- Construction of 115-kV substation at Killdeer for McKenzie Electric (North Dakota).
- Reliability improvements at the Shasta Switchyard (California).
- Anticipate substation activity in support of wind farm development, Ft. Thompson-Rolling Thunder Transmission Project, and various interconnections or integration of customer owned equipment at Western facilities.

Other	**5,060**	**5,371**	**7,846**
▪ **Communications Systems**	**3,165**	**3,664**	**5,386**

Each project cost is determined using the actual costs of recent similar projects, estimated quantities

	(dollars in thousands)	
FY 2007	FY 2008	FY 2009

of needed materials, past contract costs, specialized cost estimating guides, and in-house experience.

- Continue to replace/modernize/expand communication systems (microwave, fiber optic, global information system, and telecommunication) in the Central Valley Project and the Pick-Sloan Missouri Basin Program to operate and control the transmission system, including construction of an alternate control center for the Sierra Nevada Region sub-control area. Replacement parts for existing obsolete communications systems are difficult to obtain and the increased use of remote control of facilities, coupled with the need for greater integration of the Federal system with the rest of the grid and technological advances in the communications field, make secure and reliable communications crucial to Western's mission. Rapid advances in technology and manufacturers' phase-out of support for existing systems drive the need for communications replacements and upgrades. Effective control of remote facilities is crucial to the operation of the power system. Western's communication systems are made up of approximately 7 percent fiber optics, 81 percent fixed radio, and 12 percent mobile radio. Western currently has 1,381 radio frequency authorizations for fixed radio bands, of which 586, or 42 percent, are analog. The equipment requested here is not included in the Spectrum Relocation Fund initiative.

	FY 2007	FY 2008	FY 2009
▪ **Miscellaneous**	**1,895**	**1,707**	**2,460**

- Ongoing replacement of Dawson maintenance building (Montana) built in 1952 to provide facilities for housing motorized and movable equipment along with storage, shop areas, and crew quarters. Eight crew members are located at this duty station. Current conditions foster increased safety hazards, diminished security, increased outage response times, and decreased work efficiency for this crew. Lack of storage exposes equipment to severe weather conditions.
- Construction of maintenance building at Watertown (South Dakota) to provide facilities for housing motorized and movable equipment along with storage and shop areas.
- Rehabilitation of approximately one mile of the access road to Mead Substation (Nevada). The road has been washed out numerous times and maintenance crews cannot access the critical Mead substation until debris is cleared, creating a reliability and security concern as well as hazardous safety conditions.
- Demolition and environmental cleanup of the Mesa Substation (Arizona) that has been taken out of service.
- Annual power facility development costs and miscellaneous minor construction jobs that are not normally scheduled in advance or anticipated as part of larger projects.

	FY 2007	FY 2008	FY 2009
Preconstruction Activities	**0**	**0**	**0**

The following project will have active preconstruction activities during FY 2009: Replacement of overhead ground wire with optical ground wire to improve system connectivity, protection, and security of facilities in Western's Sierra Nevada Region (California).

	FY 2007	FY 2008	FY 2009
Total, Construction and Rehabilitation	**60,205**	**62,419**	**74,544**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Transmission Lines and Terminal Facilities	
▪ The decrease in Transmission Lines and Terminal Facilities is due primarily to the planned completion of several transmission line rehabilitation projects; primarily, Parker-Blythe, Parker-Gila, Cheyenne-Miracle Mile, and Casa Grande-Empire Projects. The decrease associated with the planned completion of these activities is offset by requested funding for additional rehabilitation efforts associated with the several ongoing and new project starts. The requested funding will allow Western to repair, rebuild, or relocate structures that have been identified as having system reliability, safety, and/or maintenance problems.	-602
Substations	
▪ This increase is due primarily to several substation rehabilitation efforts ongoing from FY 2008 that will be moving into the rebuild phase. In addition, several more substation rehabilitation efforts will begin in FY 2009 reflecting the aging infrastructure across Western's service territory, as well as increasing demand on the Federal transmission facilities.	+10,252
Other	
▪ Funding needs for Other capital expenditures, including communications, buildings, roads, and other miscellaneous construction activities is increasing to provide for construction of an alternate control center for the Sierra Nevada Region sub-control area. The alternate control center is critical for continued operations and power delivery to control area loads and power customers during a catastrophic event that would limit the access or operation of the primary control center. The alternate control center is necessary to meet NERC and WECC recommendations.	+2,475
Total Funding Change, Construction and Rehabilitation	**+12,125**

OBN0005C, O'Banion 500-kV Transmission Line and Transformation Station, O'Banion, California

1. Significant Changes

The most recent DOE O 413.3A approved Critical Decision (CD) is CD-0, Mission Need Statement, approved on April 13, 2006 with a Total Project Cost of $150 million.

This PDS is an update of the initial FY 2008 PDS. There are no significant changes in scope, cost, or schedule.

2. Design, Construction, and D&D Schedule

(fiscal quarter or date)

	CD-0	CD-1 (Design Start)	(Design/PED Complete)	CD-2	CD-3 (Construction Start)	CD-4 (Construction Complete)	D&D Start	D&D Complete
FY2008	4/13/06	2Q FY2008	2Q FY2011		3Q FY2011	2Q FY2013	NA	NA
FY2009	4/13/06	3Q FY2008	2Q FY2011		3Q FY2011	2Q FY2013	NA	NA

CD-0 – Approve Mission Need
CD-1 – Approve Alternative Section and Cost Range
CD-2 – Approve Performance Baseline
CD-3 – Approve Start of Construction
CD-4 – Approve Start of Operations or Project Closeout
D&D Start – Start of Demolition and Decontamination (D&D) work
D&D Complete – Completion of D&D work

3. Baseline and Validation Status

(dollars in thousands)

	TEC, PED	TEC, Construction	TEC, Total	OPC, Except D&D	OPC, D&D	OPC, Total	TPC
FY 2008	0	150,000	150,000	0	0	0	150,000
FY 2009	0	150,000	150,000	0	0	0	150,000

No baseline has been established. There are no Other Project Costs (OPC) since all costs are required to be within project costs by FERC accounting methods. No construction funds will be used until the Performance Baseline has been established (4Q FY2009) and validated.

4. Project Description, Justification, and Scope

Project description: New transmission lines, system interconnections and/or upgrades of existing transmission facilities in the Sacramento, CA area to assure the reliability of electricity supplies.

Justification: The project addresses a gap in the reliability of electricity supplies in the Sacramento, CA area hindered by capacity limitations on Western's existing 230-kV transmission lines. The reliability is already compromised as evidenced by the recent use of load shedding to balance supply and demand.

The electricity supplies are becoming more unreliable as existing facilities are strained to meet demand in a region that is expected to grow annually by 2.7 percent until 2030 and beyond. The 500-kV transmission line project addresses necessary improvements to the existing system to meet the demand and increased capacity needs in the area.

Scope: Requirements to be determined at CD-1.

The project is being conducted in accordance with the project management requirements in DOE Order 413.3A and DOE Manual 413.3-1, Program and Project Management for the Acquisition of Capital Assets, and all appropriate project management requirements have been met.

Compliance with Project Management Order

- Critical Decision – 0: Approve Mission Need – FY2006 (4/13/06 complete)
- Critical Decision – 1: Approve Preliminary Baseline Range – 3Q FY 2008
- External Independent Review Final Report – 3Q FY 2009
- Critical Decision – 2: Approve Performance Baseline – 4Q FY 2009
- Critical Decision – 3: Approve Start of Construction – 3Q FY 2011
- Critical Decision – 4: Approve Start of Operations – 2Q FY 2013

5. Financial Schedule (dollars in thousands)

	Appropriations	Obligations	Costs [a]
Design/Construction by Fiscal Year			
Design			
2008	5,000	5,000	
2009	8,000	8,000	
2010	3,000	3,000	
2011	2,000	2,000	
Total, Design	18,000	18,000	
Construction			
2010	27,000 [b]	27,000	
2011	38,000	38,000	
2012	40,000	40,000	
2013	27,000	27,000	
Total, Construction	132,000	132,000	
TEC			
2008	5,000	5,000	
2009	8,000	8,000	
2010	30,000	30,000	
2011	40,000	40,000	
2012	40,000	40,000	
2013	27,000	27,000	
Total, TEC	150,000	150,000	

[a] Detailed cost schedule will be reflected after completion of the CD-1.
[b] Long lead procurement; estimate is for large electrical equipment with significant lead time for delivery prior to initiation of construction contract.

6. Details of Project Cost Estimate

(dollars in thousands)

Total Estimated Cost	Current Total Estimate	Previous Total Estimate	Original Validated Baseline[a]
Preliminary and Final Design (not PED)	18,000	18,000	
Construction	132,000	132,000	
Site Preparation	NA	NA	
Equipment	NA	NA	
Other construction	NA	NA	
Contingency	NA	NA	
Total, Construction	132,000	132,000	
Total, TEC	150,000	150,000	
Other Project Cost (OPC)			
OPC except D&D			
Conceptual Planning	NA	NA	
Conceptual Design	NA	NA	
Start-up	NA	NA	
Contingency	NA	NA	
Total, OPC except D&D	NA	NA	
D&D			
D&D	NA	NA	
Contingency	NA	NA	
Total, D&D	NA	NA	
Total, OPC	NA	NA	
Total, TPC	150,000	150,000	

7. Schedule of Project Costs

For schedule of project costs, see Section 5, "Financial Schedule."

8. Related Operations and Maintenance Funding requirements

Start of Operation (fiscal quarter)	2Q2013
Expected Useful Life (number of years)	35-50
Expected Future start of D&D for new construction (fiscal quarter)	NA

[a] Not applicable at this time. Original Validated Baseline to be established after CD-2 approval.

(Related Funding requirements)

(dollars in thousands)

	Annual Costs		Life cycle costs	
	Current estimate	Prior Estimate	Current estimate	Prior Estimate
Operations	0,000	0,000	0,000	0,000
Maintenance	0,000	0,000	0,000	0,000
Total, Operations & Maintenance	0,000	0,000	0,000	0,000

9. Required D&D Information

Western plans to upgrade existing transmission facilities to increase the transfer capability in the area. D&D is not applicable and FERC accounting methods are required for utility capital investments.

Name(s) and site location(s) of existing facility(s) to be replaced: NA

D&D Information Being Requested	Square Feet
Area of new construction	NA
Area of existing facility(ies) being replaced	NA
Area of any additional space that will require D&D to meet the “one-for-one” requirement	NA

Western’s transmission facilities are not offices, nor buildings, but transmission lines and substations.

10. Acquisition Approach (formerly Method of Performance)

Design expected to be by Western staff. Acquisition has not yet been planned. Construction is anticipated to be by competitive procedures.

Purchase Power and Wheeling
Funding Schedule by Activity

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Purchase Power and Wheeling			
Central Valley Project	219,846	238,671	270,472
Pick-Sloan Missouri Basin and Other Programs	208,085	236,583	255,488
Subtotal, Purchase Power and Wheeling (Gross)	427,931	475,254	525,960
Use of Alternative Financing	-148,931	-166,552	-197,842
Subtotal, Purchase Power and Wheeling	279,000	308,702	328,118
Offsetting Collections Realized	-279,000	-308,702	-328,118
Total, Purchase Power and Wheeling (Budget Authority)	0	0	0

Description

The mission of the Purchase Power and Wheeling (PPW) subprogram is to support Western's long-term firm power sale contractual agreements, including wheeling over non-Federal transmission lines as necessary to deliver the firm hydropower resource to customers.

The PPW subprogram supports Western's mission to market and deliver reliable, cost-based hydroelectric power and related services. These services are marketed at rates sufficient to recover expenses and Federal investment as established by law. To maximize the marketability of Western's products, Western has entered into long-term contracts with customers of the Central Valley Project (CVP), the Pick-Sloan Missouri Basin Program, as well as other projects, to deliver power based on the normal (average over the long-term) amount of power and/or capacity available from each of the power systems. By its nature, hydropower is a variable resource; it is affected by reservoir storage, drought conditions, powerplant maintenance and other project purposes. Variations occur between load and the hydro-generation hour-by-hour or even minute-by-minute. Western buys power and related transmission services to fulfill its firm power-sale contractual commitments. Western also buys transmission services, as needed, to provide the benefits of the Federal hydropower resource to numerous Federal, State, municipal, and other preference customers not directly connected to Western's system. Contracting for transmission services encourages the widespread use principle of the Flood Control Act of 1944 and avoids unnecessary Federal duplication of available transmission resources. The acquisition of non-Federal power and transmission services meets Western's power marketing contract provisions which place binding responsibilities on Western to provide firm power to customers of the Pick-Sloan Missouri Basin Program-Eastern Division, Loveland Area Projects and Parker-Davis Project.

The FY 2009 request provides for continuation of PPW receipt funded activities at the estimated level necessary to meet contractual firming needs. No appropriated budget authority is necessary. The request for receipt authority reflects current drought conditions affecting the Pick-Sloan Missouri River Basin, and the elevated market pressures for purchase power across Western's service territory.

The following table illustrates the PPW program assumptions and includes actual FY 2006 amounts.

Purchase Power and Wheeling Program Assumptions

	FY 2006 Actual	FY 2007 Enacted	FY 2008 Enacted	FY 2009 Request
Power Purchases (gigawatthours)				
Central Valley Project	2,891	3,610	3,115	4,195
Pick-Sloan Missouri Basin and Other Programs	4,199	4,899	4,414	4,781
Total, Purchases	7,090	8,509	7,529	8,976
Purchase Power Prices ($/megawatthour)				
Central Valley Project	52.7	50.6	64.4	54.5
Pick-Sloan Missouri Basin and Other Programs	54.0	39.9	49.3	49.6
Cost of Power Purchases ($000)				
Central Valley Project	152,414	182,765	200,532	228,601
Pick-Sloan Missouri Basin and Other Programs	226,684	195,703	217,701	236,890
Total, Purchase Power Costs	379,098	378,468	418,233	465,491
Wheeling Costs ($000)				
Central Valley Project	31,153	37,081	38,139	41,871
Pick-Sloan Missouri Basin and Other Programs	9,763	12,382	18,882	18,598
Total, Wheeling Costs	40,916	49,463	57,021	60,469
Total, Purchase Power and Wheeling ($000)	420,014	427,931	475,254	525,960

Detailed Justification

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Central Valley Project	**91,214**	**102,947**	**109,706**

No appropriations are requested. This is authority to use offsetting collections only.

▪ **Central Valley Project, Program Requirement**	**219,846**	**238,671**	**270,472**

In FY 2009, Western continues to deliver on its contractual power commitments to customers under the Central Valley Project's Post 2004 Marketing Plan. The budget request assumes current full load service customers will continue to choose service from Western through "Custom Product" contractual arrangements. Western also purchases power to support variable resource customers on a pass-thru basis. If project net generation is not sufficient, Western may also purchase to support project use load, First Preference Customer load, and sub-control area reserve requirements.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

The FY 2009 request provides for increasing CVP purchase power and wheeling activity reflecting growing customer requests for energy services. As shown in the following paragraph, the majority of the costs of these services will be alternatively financed. The FY 2009 request also reflects a reduction in the price of purchased power on the West Coast.

▪ **Central Valley Project, Alternative/Customer Financing**	**-128,632**	**-135,724**	**-160,766**

Contractual arrangements have been made with customers providing opportunities for alternative financing of the purchase power requirements. Alternative financing methods include net billing, bill crediting, and direct customer funding.

Pick-Sloan Missouri Basin and Other Programs	**187,786**	**205,755**	**218,412**

No appropriations are requested. This is authority to use offsetting collections only.

▪ **Pick-Sloan Missouri Basin and Other Programs, Program Requirement**	**208,085**	**236,583**	**255,488**

In FY 2009, the request continues to support long-term firm power commitments to customers of the Eastern and Western divisions of the Pick-Sloan Missouri Basin Program, the Fryingpan-Arkansas Project, and the Parker-Davis Project commensurate with the levels of average firm hydroelectric energy marketed by Western. The request also provides transmission support for the Pacific Northwest-Southwest Intertie Project. The total program estimates shown for FY 2009 are based primarily on market pricing of short-term firm energy, negotiated transmission rates, and Western and generating agency' forecasts. The FY 2009 program is elevated reflecting continuing drought conditions in the Pick-Sloan Missouri River Basin area leading to greater purchase power requirements.

▪ **Pick-Sloan Missouri Basin and Other Programs, Alternative/Customer Financing**	**-20,299**	**-30,828**	**-37,076**

Alternative financing methods negotiated with customers will be used where effective to provide an offset to the total program receipt financing requirement.

Total, Purchase Power and Wheeling	**279,000**	**308,702**	**328,118**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Central Valley Project	
▪ The gross PPW requirement of $270.5 million in FY 2009 is up $31.8 million from the $238.7 million level anticipated in FY 2008. Reflecting growing customer interest in CVP energy services, purchase power levels are expected to rise to 4,195 GWhs, at a cost of $228.6 million in FY 2009; compared to 3,115 GWhs at a cost of $200.5 million in FY 2008. The majority of these purchases will be alternatively financed. The average purchase price, based on current conditions, is expected to decrease from $64.4/MWh budgeted in FY 2008 to $54.5/MWh in FY 2009; a 14 percent decrease. Western expects an inflationary increase in transmission costs; at $41.9 million, FY 2009 wheeling is up slightly from the $38.1 million estimated for FY 2008.	
▪ Note: The PPW amounts are for offsetting collection authority and alternative financing; no direct appropriations are necessary.	+31,801
Pick-Sloan Missouri Basin and Other Programs	
▪ The gross PPW requirement of $255.5 million in FY 2009 is up by $18.9 million from the $236.6 million enacted in FY 2008. The increase reflects affects of the long-term drought conditions experienced in the Pick-Sloan Missouri River Basin for the last several years. As a result, purchase power requirements are expected to remain higher than the 4,414 GWhs budgeted in FY 2008; FY 2009 is estimated at 4,781 GWhs. Average purchase power prices are expected to moderate from the higher $54/MWh levels seen in FY 2006. FY 2009 average prices, at just over $49.6/MWh, remain at a level similar to that budgeted for FY 2008. Wheeling costs for FY 2009 at $18.6 million are reduced slightly from the FY 2008 budgeted level.	
▪ Note: The PPW amounts are for offsetting collection authority and alternative financing; no direct appropriations are requested for this activity.	+18,905
Total Funding Change, Purchase Power and Wheeling	**+50,706**

Program Direction
Funding Profile by Category

	(dollars in thousands)		
	FY 2007	FY 2008[a]	FY 2009
Program Direction [b]			
Salaries & Benefits	104,894	109,213	114,527
Travel	8,150	8,327	8,382
Support Services	20,458	20,429	24,265
Other Related Services	14,246	18,159	19,249
Total, Program	147,748	156,128	166,423
Less Use of Alternative Financing	-5,054	-10,000	-15,800
Use of Receipts from Colorado River Dam Fund	-2,959	-3,008	-2,563
Total, Program Direction Budget Authority	139,735	143,120	148,060
Full-time Equivalents	1,074	1,081	1,070

Mission

Western's Program Direction subprogram provides compensation and all related expenses for the workforce that operates and maintains Western's high-voltage interconnected transmission system and associated facilities; those that plan, design, and supervise the construction of replacements, upgrades and additions (capital investments) to the transmission facilities; and those that market the power and energy produced to repay annual expenses and capital investment.

The Program Direction subprogram supports DOE's Energy Security Strategic Theme, Goal 1.3, Energy Infrastructure. To attain reliability performance, dispatchers match generation to load minute-by-minute to meet or exceed performance levels established by NERC. Western maintains the interconnected system at or above industry standards to reduce transmission outages. Energy schedulers maximize revenues from non-firm energy sales and power rates are reviewed and adjusted to support repayment of Federal investment. Western trains its employees on a continuing basis in occupational safety and health regulations, policies and procedures, and conducts safety meetings at employee, supervisory and management levels to keep the safety culture strong. Accidents are reviewed to ensure lessons are learned and proper work protocol is in place.

The Program Direction subprogram further supports Western's Human Capital Management (HCM) Workforce Plan. HCM Workforce Plan activities include: exploring ways to increase HR efficiency through consolidation; the development and/or expansion of intern/apprenticeship programs in the occupations of energy marketing, dispatcher, lineman, and electrician; introduction of an under-study program in Power Marketing, prior to an incumbent retiring; rotational training programs for engineers; strategic use of knowledge sharing and training events in critical occupations; and, succession planning

[a] FY 2008 adjustment reflects the 0.91 percent general rescission of $1,175,613 (P.L. 110-161).
[b] Program descriptions and funding amounts include activities of the Boulder Canyon Project. These activities are funded through a Reimbursable Agreement with the Department of the Interior, Bureau of Reclamation.

development programs for mid- to upper-level graded Federal positions. By design, costs for these HCM programs will be minimal as local area expertise and facilities will be used to the maximum extent possible. The HCM Workforce Plan noted that no new A-76 studies were required and/or anticipated at this time.

Western operates and maintains a transmission system to deliver reliable electric power in a clean and environmentally-safe, cost-effective manner within its 15-State service territory. Western achieves continuity of service by maintaining its power system at or above industry standards, rapidly restoring service following any system disturbance, mitigating adverse environmental impacts, performing environmental clean-up activities, and maximizing the benefits gained from non-firm energy sales. Additionally, Western operates the Western Electricity Coordinating Council's Rocky Mountain/Desert Southwest Reliability Coordination Center.

In concert with its customers, Western reviews required replacements and upgrades to its existing infrastructure to sustain reliable power delivery to its customers and to contain annual maintenance expenses. The timing and scope of these replacements and upgrades are critical to assure that Western's facilities do not become the "weak link" in the interconnected system. Western pursues opportunities to join with neighboring utilities to jointly finance activities, which avoid redundant facilities and result in realized cost savings and/or increased efficiencies for all participants.

Detailed Justification

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Salaries and Benefits	**104,894**	**109,213**	**114,527**

Salaries and benefits are provided for Federal employees to operate and maintain, on a continuing basis, Western's high-voltage interconnected transmission system comprised of 17,008 circuit-miles of line, 296 substations, associated power system control and communication, and general plant facilities. Craft workers rapidly restore the transmission system following any disturbance, and routinely maintain and/or replace equipment to assure capability for reliable delivery of power. Dispatchers provide 24-hour-a-day operation of four dispatching centers and one reliability coordination center. Dispatchers respond to minute-by-minute changes to load and generation to meet or exceed NERC and industry averages for system reliability and performance. Engineers and craft workers maintain the interconnected system at or above industry standards to reduce transmission outages. Energy schedulers maximize revenues from non-firm energy sales. Staff provides continuing services such as system operations, power billing and collection, power marketing, rate setting, energy services, environmental, safety, security and emergency management. Due to the extreme hazards associated with a high-voltage electrical system, staff makes safety a priority in each and every task. Staff inspects construction activities in progress (identified in the Construction and Rehabilitation activity) to ensure quality results and safe working methods. General power resources planning and preconstruction activities continue, including planning, environmental clearance, collection of field data, design of facilities, and issuance of specifications for future rehabilitation and upgrades of existing transmission lines and the review/coordination of requests for transmission system interconnections. Staff evaluates general power resources, collaborating and planning with customers and other members of the interconnected transmission system, to identify the most effective transmission system improvements to maximize benefits to all participants.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

Total FTE numbers for FY 2009 include 1,070 for Western's Construction, Rehabilitation, Operation and Maintenance (CROM) Account activities. Included in this amount are 15 FTE for Boulder Canyon Project (BCP) activities accomplished using receipts from the Colorado River Dam Fund under a reimbursable agreement with the Bureau of Reclamation. FTE reflected for CROM Account activities total 1,074 and 1,081 for FY 2007 and 2008, respectively, which includes the FTE associated with BCP activities of 15 for FY 2007 and 17 for FY 2008. The decrease of within target FTE reflected in FY 2009 for Western's CROM Account includes a shift in 11 FTE to Western's Colorado River Basins Power Marketing Fund (CRBPMF). The shifting of FTEs supports the increase of O&M activities within Western's CRBPMF program and does not represent a change to Western's total FTE level request for FY 2009.

The FY 2009 funding request reflects anticipated salary and within-grade increases to fund the majority of the FTE financed in this account. The program request includes approximately $1.8 million for salary and benefit activities of the Boulder Canyon Project, and other financing methods fund the remainder. Western's overall average budgeted salary/benefit costs per FTE for FY 2008 and FY 2009 are $101,030, and $107,035 respectively. More than 38 percent of Western's personnel salaries and compensation policies are determined through wage surveys and union negotiations (craft workers, power system dispatchers, schedulers, and marketers) and become effective at the beginning of a fiscal year rather than in January as do the General Schedule increases.

Travel	**8,150**	**8,327**	**8,382**

Estimates, including $138,000 for the Boulder Canyon Project, include transportation and per diem allowances for day-to-day performance of duties of Federal staff, including crews who maintain the interconnected system. The remote and rural locations in Western's 15-State service area result in less competitive pricing. Rental/lease of GSA vehicles and other transportation estimates are also included. Estimates are based on historical costs and an assessment of planned activity. The slight increase is attributable to inflation, offset by a decrease of planned travel activity.

Support Services	**20,458**	**20,429**	**24,265**

Support services funded in this category include information processing, warehousing, job related training and education, engineering, miscellaneous advisory and assistance services, and general administrative support. The Boulder Canyon portion of the support services estimate totals $328,000. The increase to this activity is required to support Western's mission needs in communication, operating, and planning engineering; ADP program support for the power billing system; consulting services in support of the Market Redesign Technology Upgrade (MRTU); and, administrative support associated with transmission line reliability and substation upgrades. Other increases are primarily inflationary in nature.

Other Related Expenses	**14,246**	**18,159**	**19,249**

Other related expenses include rental space, utilities, supplies and materials, telecommunications, personal computers, printing and reproduction, training tuition, and DOE's working capital fund distribution. The Boulder Canyon portion of these expenses total $255,000. Rental space costs assume the General Services Administration's (GSA) inflation factor. Other costs are based on historical usage

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
and actual cost of similar items. The increase is due to additional A&E requirements and inflationary factors, slightly offset by a decrease in rental space, printing and reproduction, and estimates for services from other government agencies. Also decreasing is miscellaneous other expenses to include supplies and services from Western's indirect distribution to this account.			
Total, Program Direction	**147,748**	**156,128**	**166,423**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Salaries and Benefits	
▪ The increase to salary and benefits includes anticipated salary increases to fund the FTE financed in this account, to include those salaries determined through negotiations.	+5,314
Travel	
▪ The slight increase is attributable to inflation, offset by a decrease of planned travel activity.	+55
Support Services	
▪ The increase to this activity is required to support Western's mission needs in communication, operating, and planning engineering; ADP program support for the power billing system; consulting services in support of the Market Redesign Technology Upgrade (MRTU); and, administrative support associated with transmission line reliability and substation upgrades. Other increases are primarily inflationary in nature.	+3,836
Other Related Expenses	
▪ The increase is due to additional A&E requirements and inflationary factors, slightly offset by a decrease in rental space, printing and reproduction, and estimates for services from other government agencies. Also decreasing is miscellaneous other expenses to include supplies and services from Western's indirect distribution to this account.	+1,090
Total Funding Change, Program Direction	**+10,295**

Support Services by Category

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Technical Support			
Economic and Environmental Analysis	1,372	1,498	2,738
Test and Evaluation Studies	0	0	0
Total, Technical Support	1,372	1,498	2,738
Management Support			
Management Studies	0	0	0
Training and Education	0	906	1,006
Automated Data Processing	4,979	5,909	6,284
Reports and Analyses Management and General Administrative Services	14,107	12,116	14,237
Total, Management Support	19,086	18,931	21,527
Total, Support Services	20,458	20,429	24,265

Other Related Expenses by Category

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Training	650	294	364
Working Capital Fund	759	735	1,174
Printing and Reproduction	126	135	104
Rental Space	2,033	2,016	1,858
Software Procurement/Maintenance Activities/Capital Acquisitions	3,171	2,899	3,940
Purchases from Government Accounts	1,023	1,553	1,131
Architectural and Engineering Services	0	1,822	2,889
Other Miscellaneous Expenses	6,484	8,705	7,789
Total, Other Related Expenses	14,246	18,159	19,249

Utah Mitigation and Conservation
Funding Schedule by Activity

	(dollars in thousands)		
	FY 2007	FY 2008[a]	FY 2009
Total, Utah Mitigation and Conservation Budget Authority	6,633	7,114	7,342

Description

The Reclamation Projects Authorization and Adjustment Act of 1992, Title IV, established the Utah Reclamation Mitigation and Conservation Account (Account) in the Treasury of the United States. The purpose of this Account is to ensure that the level of environmental protection, mitigation, and enhancement achieved in connection with projects identified in the Act and elsewhere in the Colorado River Storage Project in the State of Utah is preserved and maintained. The Administrator of Western is authorized to deposit funds into the Account. Such expenditures are to be considered non-reimbursable and non-returnable. The Utah Reclamation Mitigation and Conservation Commission established under Title III of the Act, is authorized to administer all funds deposited into this Account.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Utah Mitigation and Conservation	**6,633**	**7,114**	**7,342**
A deposit of $7,342 thousand will be made to this Account.			
Total, Utah Mitigation and Conservation	**6,633**	**7,114**	**7,342**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Utah Mitigation and Conservation	
▪ This increase is based on the required calculation using factors found in the Economic Assumptions, CPI – Urban Customers.	+228
Total Funding Change, Utah Mitigation and Conservation	**+228**

[a] FY 2008 adjustment reflects the 0.91 percent general rescission of $53,563 (P.L. 110-161).

Falcon and Amistad Operating and Maintenance Fund

Funding Profile by Subprogram

(dollars in thousands)

	FY 2007 Current Appropriation	FY 2008 Original Appropriation	FY 2008[a] Adjustments	FY 2008 Current Appropriation	FY 2009 Request
Falcon and Amistad Operating and Maintenance Fund	2,665	2,500	-23	2,477	2,959
Total, Falcon and Amistad Operating and Maintenance Fund (Budget Authority)	2,665	2,500	-23	2,477	2,959

Public Law Authorizations:
Public Law 103-236, "Foreign Relations Authorization Act, Fiscal Years 1994 and 1995"
The Act of June 18, 1954 (68 Stat. 255)

Mission

The Falcon and Amistad Operating and Maintenance Fund (Maintenance Fund) was established in the Treasury of the United States as directed by the Foreign Relations Authorization Act, Fiscal Years 1994 and 1995. The Maintenance Fund is administered by the Administrator of Western for use by the Commissioner of the U.S. Section of the International Boundary and Water Commission (IBWC) to defray administrative, O&M, replacements, and emergency costs for the hydroelectric facilities at the Falcon and Amistad Dams.

The Falcon-Amistad Project hydroelectric power generation plants sell generated power to rural electric cooperatives through Western. The United States' share of the generating capacity of the two powerplants is 97.5 MW. All revenues collected in connection with the disposition of electric power generated at the Falcon and Amistad Dams, except monies received from the Government of Mexico, are credited to the Maintenance Fund. Any monies received from the Government of Mexico are credited to the General Fund of the U.S. Treasury. Revenues collected in excess of expenses are used to repay, with interest, the cost of replacements and original investments, thus supporting Western's Program Goal. Full funding will support 24-hour/day operation and maintenance of the two powerplants to ensure response to ever-changing water conditions, customer demand, and continual coordination with operating personnel of the Government of Mexico. In addition, power will be marketed, repayment studies will be completed, and revenues collected. The Federal staff funded under this program continues to be allocated to the U.S. Section of IBWC by the Department of State.

[a] FY 2008 adjustment reflects the 0.91 percent general rescission of $22,750 (P.L. 110-161).

Falcon and Amistad Operating and Maintenance Fund
Funding Schedule by Activity

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Falcon and Amistad Operating and Maintenance Fund			
Salaries and Benefits	1,754	1,785	1,965
Routine Services	783	573	803
Miscellaneous Expenses	108	104	176
Marketing, Contracts, Repayment Studies	20	15	15
Emergency Contingency	0	0	0
Total, Falcon and Amistad Operating and Maintenance Fund	2,665	2,477	2,959

Detailed Justification

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Salaries and Benefits	**1,754**	**1,785**	**1,965**

Salaries and benefits are provided for 35 positions of the U.S. Section of the IBWC who operate and maintain the two power plants on a 24-hour/day basis, including planned maintenance activities, required safety services, and emergency response to flood operations and/or equipment failure. The slight increase is attributed to promotions, salary, and cost of living adjustments.

Routine Services	**783**	**573**	**803**

Routine services such as inspection and service of the HVAC and air compressor systems, fire suppression systems, elevators, self-contained breathing apparatus, recharge and hydro-testing of fire extinguishers, calibration of test equipment, rebuild of electric motors, and repair of obsolete equipment when replacement parts are no longer available, will be provided The request includes capitalized estimates of $232,000 to plan and design a new Supervisory Control and Data Acquisition (SCADA) System within the Amistad power plant. This system is necessary to improve and enhance the ability to monitor installed equipment, and to perform trend analyses to detect future problems before catastrophic damage occurs. Also included in the capitalized estimates is $66,000 for the preliminary design to upgrade the generator and transformer electrical protection, and $11,000 for designing and installing an updated lubrication system for the wicket gates.

Miscellaneous Expenses	**108**	**104**	**176**

Estimates include miscellaneous expenses for IBWC employees and technical advisors, including travel, training, communications, utilities, printing, and office supplies and materials. Planned training and travel activities include that which is essential for flood response, dam safety, power house safety, to comply with the standards of the Interagency Commission on Dam Safety (ICODS), Occupational Safety and Health Administration (OSHA), the National Dam Safety Act, and to participate in the international efforts of drought management. The increase in this activity is attributed to inflation, an

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
increase to utility estimates, and replacement of obsolete computer equipment.			
Marketing, Contracts, Repayment Studies	**20**	**15**	**15**
Costs for marketing power, administration of power contracts, and preparation of rate and repayment studies are included. Based on accurate studies, staff ensures that power revenues are set at an appropriate level to recover annual expenses and meet repayment schedules.			
Total, Falcon and Amistad Operating and Maintenance Fund Budget Authority	**2,665**	**2,477**	**2,959**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Salaries and Benefits	
▪ The increase is attributed to promotions, salary, and cost of living adjustments.	+180
Routine Services	
▪ The increase in routine services is attributable to an increase in operation and maintenance activities charged to this account. These services include the fiber optic network upgrade at both the Falcon and Amistad power plants, plan and design of SCADA system at Amistad power plant, and preliminary design to upgrade the generator and transformer electrical protection, also at the Amistad power plant.	+230
Miscellaneous Expenses	
▪ The increase in this activity is attributed to inflation, an increase to utility estimates, and replacement of obsolete computer equipment.	+72
Total Funding Change, Falcon and Amistad Operating and Maintenance Fund	**+482**

Colorado River Basins Power Marketing Fund

Funding Profile by Subprogram

(dollars in thousands)

	FY 2007 Current Appropriation	FY 2008 Current Appropriation	FY 2008 Adjustments	FY 2008 Current Appropriation	FY 2009 Request
Colorado River Basins Power Marketing Fund					
Equipment, Contracts and Related Expenses	144,080	190,444	0	190,444	195,137
Program Direction	42,141	41,701	0	41,701	45,147
Total, Operating Expenses from new authority	186,221	232,145	0	232,145	240,284
Offsetting Collections Realized	-186,221	-255,145	0	-255,145	-263,284
Total, Obligational Authority	0	-23,000	0	-23,000	-23,000

Public Law Authorizations:
Public Law 75-529, "The Fort Peck Project Act of 1938"
Public Law 84-484, "The Colorado River Storage Project Act of 1956"
Public Law 90-537, "The Colorado River Basin Project Act of 1968"
Public Law 95-91, "Department of Energy Organization Act" (1977)

Mission

Western operates and maintains the transmission system for the projects funded in this account to ensure an adequate supply of reliable electric power in a clean and environmentally safe, cost-effective manner. The Colorado River Basins Power Marketing Program (Program) is comprised of the three power systems: the Colorado River Storage Project, including the Dolores and Seedskadee Projects; the Fort Peck Project, and the Colorado River Basin Project. This program is funded through Western's business-type revolving fund (Federal Enterprise Fund), the Colorado River Basins Power Marketing Fund.

Western achieves continuity of service by maintaining its power systems at or above industry standards, rapidly restoring service following any system disturbance, mitigating adverse environmental impacts, performing clean-up activities, and maximizing the revenues gained from non-firm energy sales. In concert with its customers, Western reviews required replacements to its existing infrastructure to sustain reliable power delivery to its customers and to contain annual maintenance expenses.

Revenues from the sale of electric energy, capacity and transmission services replenish the fund and are available for expenditure for operation, maintenance, replacements, power billing and collection, program direction, purchase power and wheeling, interest, emergencies, and other power marketing expenses. Power sales and other revenues, which are collected in excess of expenses, are used to repay Federal investments to the U.S. Treasury. This request represents Western's estimate of obligations to finance these business-type operations.

Equipment, Contracts and Related Expenses

Funding Schedule by Activity

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Equipment, Contracts and Related Expenses			
Supplies, Materials, and Services	11,203	11,148	12,837
Purchase Power Costs	123,286	162,213	164,284
Capitalized Equipment	9,591	6,421	6,171
Interest/Transfers	0	10,662	11,845
Total, Equipment, Contracts and Related Expenses	144,080	190,444	195,137

Description

This program supports the Department of Energy's Strategic Theme, Goal 1.3, Energy Infrastructure. Western ensures an adequate supply of reliable electric power in a safe, cost-effective manner, and achieves continuity of service throughout its service territory by maintaining its power system at or above industry standards, rapidly restoring service following any system disturbance, mitigating adverse environmental impacts, performing clean-up activities, and maximizing the revenues gained from ancillary services and cost-based non-firm energy sales.

Western's equipment, contracts and related expenses are necessary to operate and maintain this activity. Revenues from the sale of electric energy, capacity and transmission services replenish the fund and are available for expenditure for operation, maintenance, power billing and collection, program direction, purchase power and wheeling, interest, emergencies, and other power marketing expenses.
Supplies and materials, such as wood poles, instrument transformers, meters and relays, must be procured to provide necessary resources to respond to routine and emergency situations in the high-voltage interconnected transmission system. Technical services, such as waste management disposal and pest/weed control, are used as needed.

Western's planned replacement and addition activity is based on an assessment of age and the maintenance frequency/problems of individual items of equipment, availability of replacement parts, safety of the public and Western's personnel, environmental concerns, and an orderly work plan. The work plans, coordinated with Western's customers who ultimately bear the burden of all Western expenses, reflect an overall sustainable level of effort, with shifts in emphasis between categories (i.e. electrical versus communication equipment) in any given year.
Electrical equipment replacements, such as circuit breakers, transformers, insulators, revenue meters, switches, control boards, relay and controls must be acquired to assure reliable service to Western's customers. System age and environmental concerns necessitate orderly replacement before significant problems develop.

Replacement and upgrade of microwave, SCADA, and other communication and control equipment continues to provide increased system reliability, and reduce maintenance and equipment costs.

Capitalized movable equipment such as special purpose vehicles (e.g., truck tractor, diggers), special purpose equipment (e.g., pole trailers, brush chippers), specialized test equipment (e.g., motion analyzers and relay test equipment), computer-aided engineering equipment, office equipment, IT equipment and software must be upgraded and replaced.

Electrical resources and transmission capability to firm up the Federal hydropower supplies needed to meet Western's contractual obligations will continue to be obtained. Transmission wheeling services are also purchased when a third party's transmission lines are needed to deliver Federal power to Western's customers.

Reimbursements to the U.S. Army Corps of Engineers for operation and maintenance of the Fort Peck Powerplant and planned interest payments to the U.S. Treasury are also included in this section.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Supplies, Materials, and Services	**11,203**	**11,148**	**12,837**

Supplies, materials, and services necessary to respond to routine and emergency situations in the high-voltage interconnected transmission system will be procured, and reimbursements to the U.S. Army Corps of Engineers for operation and maintenance of the Fort Peck Powerplant will continue. A well-maintained transmission system supports Western's attainment of reliability and transmission availability performance by preventing sudden failure, unplanned outages, and possible regional power system disruptions. By providing 24-hour/day reliable electric power delivery to its customers, Western secures revenues for repayment of the Federal investment. Safe working procedures are discussed before work begins to optimize public safety, Western personnel, and equipment. The target request is based on projected work plans for activities funded from this Account. Estimates are based on historical data of actual supplies needed to maintain the transmission system reliably, including emergency situations such as ice storms and tornadoes. Costs are based on recent procurement of similar items. The increase is primarily due to a slight decreased requirement in this activity.

Purchase Power Costs	**123,286**	**162,213**	**164,284**

Electrical resources, transmission capability and wheeling services will be purchased. The request anticipates the continued low-steady-flow tests conducted at Glen Canyon Dam, as required by the Glen Canyon Dam Environmental Impact Statement Record of Decision. Additionally, amounts include obligational authority to accommodate replacement power purchases for customers served by the Colorado River Storage Project. The replacement power purchases, a provision of the Salt Lake City Area Integrated Projects electric power contracts, are made at the request of power customers at times when Western lacks sufficient generation to meet its full contract commitment. The funds for the replacement power purchases are advanced by the requestors prior to the purchase. Anticipated purchase power budget estimates increase in FY 2009 as a result of increased power costs to Western, and an increase in delivered MWh.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Capitalized Equipment	**9,591**	**6,421**	**6,171**

Capitalized equipment including circuit breakers, transformers, relays, switches, transmission line equipment, microwave, SCADA, and other communication and control equipment, will be acquired to assure reliable service to Western's customers. Replacement and upgrade of aged power system components are crucial to system reliability and transmission availability performance. Removing environmental hazards and replacing aged equipment eliminates safety hazards for the public and Western's personnel. Planned communications equipment purchases remain relatively constant and include funding for the continuation of the project to replace analog microwave with fiber optic ground wire and fiber optic terminal. Aged fiberglass communication buildings that have suffered extensive irreparable physical damage are also scheduled for replacement. Transmission line estimates include the purchase of poles, crossarms, conductors, overhead ground wire and hardware for the continued transmission line rebuilds and replacement to the 230-kV specifications of the Harvre-Rainbow line, as the current microwave system is obsolete.

Planned substation estimates include funding to upgrade the programmable logic controllers at the Pinnacle Peak Substation, and the continuation of the program to upgrade circuit switches as they are aged and worn. Also included is the replacement of air core reactors at Hayden, and reactor and breaker replacement at Shelby. Western is beginning the fourth year of a 10-year program to replace older electro-mechanical relays with microprocessor relays due to aged equipment. The microprocessor relays will assist in finding faults faster in order to more efficiently restore service to the customer. Also planned is the replacement of existing transformer monitors with Digital Temperature and Dissolved Gas monitors. This new technology enhances reliability of critical equipment. Funding is also requested to replace circuit breakers at Shiprock, Midway, and Blue Mesa, replace aged disconnect switches, and install security improvements per NERC guidelines at substation facilities. Other miscellaneous items required for substation replacements include surge arrestors, batteries and chargers, and monitoring equipment.

Planned movable capitalized property estimates include the replacement of special purpose trucks at Havre and Ft. Peck. The existing trucks have reached the end of their useful life and require major transmission rebuilds. Also requested is a new loader to clear the right-of-ways under an agreement with the Forest Service. Other estimates include the replacement of outdated test equipment, and test equipment to troubleshoot the new digital microwave radio system. Replacement is also planned for aging information technology support systems and router. The dependability of this equipment is nearing the uncertainty mark and reaching vendor end of life. Other requests include funding for the continuation SCADA Upgrade program as well as other small minor enhancements that provide for the ease of maintenance, protection of equipment and materials, and environmental compliance.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Interest/Transfers	**0**	**10,662**	**11,845**

Interest payments to the U.S. Treasury will occur. Estimates are based on Power Repayment Studies for the Projects funded in this account. The projected interest payment increases in FY 2009 primarily due to an increase in investment and a reduction in principal payments made from the prior years estimated Power Repayment Study.

Total, Equipment, Contracts and Related Expenses	**144,080**	**190,444**	**195,137**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Supplies and Materials	
▪ The increase is attributable to inflation and a slightly higher level of activity.	+1,689
Purchase Power Costs	
▪ Purchase power costs increase in FY 2009 as a result of an increase in the costs of purchase power and the delivery of additional MWh.	+2,071
Capitalized Equipment	
▪ The decrease in capitalized equipment purchases is primarily attributed to a decreased level of purchases associated with planned replacement of substation equipment offset by a slight increase in replacement of transmission line hardware.	-250
Interest	
▪ Planned interest payment to the U.S. Treasury in FY 2009 increases due to increase in investment and a reduction in principal payments made from the prior years estimated Power Repayment Study.	+1,183
Total Funding Change, Equipment, Contracts and Related Expenses	**+4,693**

Program Direction

Funding Profile by Category

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Program Direction			
Salaries and Benefits	31,631	29,913	32,113
Travel	2,372	2,182	2,362
Support Services	5,035	5,196	5,338
Other Related Expenses	3,103	4,410	5,334
Total, Program Direction	42,141	41,701	45,147
Full Time Equivalents	266	261	272

Mission

Program Direction provides the Federal staffing resources and associated costs required to provide overall direction and execution of the Colorado River Basins Power Marketing Fund. Western trains its employees on a continuing basis in occupational safety and health regulations, policies and procedures, and conducts safety meetings at employee, supervisory and management levels to keep the safety culture strong. Accidents are reviewed to ensure lessons are learned and proper work protocol is in place.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Salaries and Benefits	**31,631**	**29,913**	**32,113**

Salaries and benefits will be provided for Federal employees who operate and maintain the Program's high-voltage integrated transmission system and associated facilities; plan, design, and supervise the replacement (capital investments) to the transmission facilities; and market the power and energy produced to repay annual expenses and capital investment. Engineers and craft workers rapidly restore the transmission system, comprised of approximately 4,000 circuit-miles of transmission lines and associated substations, switchyards, communication, control and general plant facilities, following any disturbance. Staff routinely maintain and/or replace equipment to assure capability for reliable power delivery. Dispatchers respond to minute-by-minute changes to load and generation to meet or exceed the NERC and industry averages. Energy schedulers maximize revenues from non-firm energy sales, and power rates are reviewed and adjusted, thereby supporting the repayment of Federal investment. Staff provides continuing services such as system operations, power billing and collection, power marketing, energy services, technology transfer, environmental, safety, security and emergency management activities. Due to the extreme hazards associated with a high-voltage electrical system, staff makes safety a priority in each and every task. Staff evaluates general power resources, collaborating and planning with customers and members of the interconnected transmission system to

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

identify the most effective transmission system improvements to maximize benefits to all participants.

The 272 FTE supported in this account reflects both direct and indirect (portions of administrative and general expense employees). Amounts are based on planned work associated with facilities funded through this Account and not on specific positions; therefore, FTE numbers may vary from year to year. The funding increase supports the increase of within target FTE and reflects anticipated salary and within-grade increases. As authorized in P.L. 99-141, Western annually establishes pay rates and compensation policy for some employees (craft workers, power system dispatchers, schedulers, and marketers) based on prevailing rates in the electric utility industry. Due to recruitment/retention issues for those occupations across the Nation and increased staff in these categories to meet the additional workload requirements attributed to FERC Order Nos. 888 and 889, Western's Federal salary/benefit costs for the dispatching/scheduling functions increase at varying rates.

	FY 2007	FY 2008	FY 2009
Travel	**2,372**	**2,182**	**2,362**

Transportation/per diem allowances for day-to-day performance of duties of Federal staff, including crews maintaining the transmission facilities will continue. Rental/lease of GSA vehicles and transportation of things are also included. Estimates are based on historical travel costs, adjusted for inflation and planned activity. Increased levels are attributable to inflation and an increased cost of transportation and in-house operation and maintenance work activities charged to this account.

	FY 2007	FY 2008	FY 2009
Support Services	**5,035**	**5,196**	**5,338**

Support services funded in this category include IT support, warehousing, computer-aided drafting/engineering, and general administrative support. The increase is attributed to inflationary factors, an increase in overhead distribution charged to this account, a slight increase in job related training, offset by a decrease to ADP and administrative support.

	FY 2007	FY 2008	FY 2009
Other Related Expenses	**3,103**	**4,410**	**5,334**

Other related expenses include, but are not limited to, DOE's working capital fund distribution, space, utilities and miscellaneous charges, printing and reproduction, training tuition, maintenance of office equipment, supplies and materials, telecommunications, personal computers, and multi-project costs. Intermittent specialized services, not included in on-going support service contracts, are also included. Rental space costs assume the GSA inflation factor. Other costs are based on historical usage and actual cost of similar items. The request reflects inflationary increases, as well as increases from Western's overhead distribution, communications, miscellaneous contractual support, utility costs, and office equipment purchases.

	FY 2007	FY 2008	FY 2009
Total, Program Direction	**42,141**	**41,701**	**45,147**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Salaries and Benefits	
▪ Increase in salaries and benefits is attributed to the increase in FTE charged to this account, as well as salary and within grade increases, including salaries determined by prevailing rates in the electric utility industry.	+2,200
Travel	
▪ Increased levels are attributable to inflationary factors, and an increase in transportation and travel costs.	+180
Support Services	
▪ The increase is primarily attributed to inflationary factors, an increase in overhead distribution and mission related training.	+142
Other Related Expenses	
▪ The request reflects inflationary increases, as well as increases from Western's overhead distribution, communications, miscellaneous contractual support, utility costs, and office equipment purchases.	+924
Total Funding Change, Program Direction	**+3,446**

Support Services by Category

(dollars in thousands)

	FY 2007	FY 2008	FY 2009
Technical Support			
Economic and Environmental Analysis	0	0	0
Test and Evaluation Studies	0	0	0
Total, Technical Support	0	0	0
Management Support			
Management Studies	0	0	0
Training and Education	0	152	241
ADP Support	1,056	1,259	1,246
Administrative Support	3,979	3,785	3,851
Total, Management Support	5,035	5,196	5,338
Total, Support Services	5,035	5,196	5,338

Other Related Expenses by Category

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Training	266	91	31
Working Capital Fund	201	185	204
Printing and Reproduction	11	29	29
Rental Space	720	689	743
Software Procurement/Maintenance Activities/Capital Acquisitions	787	401	796
Other Services	1,118	3,015	3,531
Total, Other Related Expenses	3,103	4,410	5,334

Estimate of Gross Revenues [a]

(dollars in thousands)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Boulder Canyon Project	80,020	80,577	84,727	87,604	85,598	82,084	83,034
Central Valley Project	316,986	326,236	334,821	350,114	362,723	362,723	362,723
Central Arizona Project [b]	102,342	102,342	102,342	102,342	102,342	102,342	102,342
Falcon-Amistad Project	4,923	4,942	4,941	4,941	4,940	4,939	4,938
Fryingpan-Arkansas Project	16,487	16,965	16,001	15,841	15,044	14,910	14,910
Pacific Northwest-Southwest Intertie Project	31,173	32,944	32,944	32,944	32,944	32,944	32,944
Parker-Davis Project	50,421	48,927	46,158	43,283	40,785	46,177	46,172
Pick-Sloan Missouri Basin Program	356,343	431,011	414,094	427,999	427,130	427,130	427,544
Provo River Project	259	301	310	324	329	339	349
Washoe Project	777	777	777	777	777	777	777
Salt Lake City Area Integrated Projects	170,422	172,201	173,649	174,515	175,381	174,985	174,985
Total, Gross Revenues	1,130,153	1,217,223	1,210,764	1,240,684	1,247,993	1,249,350	1,250,718

[a] For most power systems, amounts are based on the FY 2006 Power Repayment Studies (PRS). The Central Arizona Project (CAP) amounts shown are based on estimated projections.
[b] Western has contractually agreed for the Salt River Project (SRP) to act as the scheduling entity and operating agent for CAP's portion of the Navajo Generating Station's output (547 MW). In return, as Western retains marketing responsibility, SRP agreed to pay monthly costs to cover annual expenses.

Estimate of Energy Sales[a]

	(in gigawatthours) [b]						
	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Boulder Canyon Project	3,965	3,916	4,072	4,047	4,069	4,076	4,081
Central Valley Project	9,262	9,262	9,262	9,262	9,262	9,262	9,262
Central Arizona Project (Navajo)	4,321	4,321	4,321	4,321	4,321	4,321	4,321
Falcon-Amistad Project	87	87	87	87	87	87	87
Loveland Area Projects [c]	2,123	2,123	2,123	2,123	2,123	2,123	2,123
Pacific Northwest-Southwest Intertie Project [d]	0	0	0	0	0	0	0
Parker-Davis Project	1,346	1,346	1,346	1,346	1,346	1,346	1,346
Pick-Sloan Missouri Basin Program, Eastern Division	9,197	9,579	10,055	10,470	10,467	10,478	10,490
Provo River Project	19	19	19	19	19	19	19
Washoe Project	11	11	11	11	11	11	11
Salt Lake City Area Integrated Projects [e]	5,152	5,266	5,391	5,407	5,440	5,418	5,418
Total	35,483	35,930	36,687	37,093	37,145	37,141	37,158

[a] For most power systems, sales amounts are based on FY 2006 Power Repayment Studies (PRS). The estimates for Central Arizona, Central Valley Project, Falcon-Amistad, and Provo River projects are based on average sales over the prior five years.
[b] One gigawatthour (GWh) equals one million kilowatt-hours (kWh).
[c] Loveland Area Projects include Fryingpan-Arkansas Project and the Western Division of the Pick-Sloan Missouri Basin Program.
[d] Pacific Northwest-Southwest Intertie shows no energy sales, but reflects revenues from the transmission of energy (refer to the Estimate of Revenues table). The Intertie Project is for transmission of energy only.
[e] Salt Lake City Area Integrated Projects include the Colorado River Storage Project, Collbran Project, Rio Grande Project, Seedskadee Project, and Dolores Project.

Estimate of Proprietary Receipts

(dollars in thousands)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
MANDATORY							
Falcon Amistad Maintenance Fund, 895178	3,088	2,500	2,959	3,076	3,196	3,323	3,454
Sale and transmission of electric power, Falcon and Amistad Dams, 892245	1,800	2,372	1,982	1,865	1,744	1,616	1,484
Sale of Power and Other Utilities Not Otherwise Classified, 892249	14,599	30,000	30,000	30,000	30,000	30,000	30,000
Sale of Power–Western–Reclamation Fund, 895000.27	143,823	199,967	123,776	180,742	135,869	136,515	140,979
Total, Mandatory Receipts	163,310	234,839	158,717	215,683	170,809	171,454	175,917
DISCRETIONARY							
Offsetting Collections from the recovery of power related expenses – Western – 89X5068.01	278,923	308,702	328,118	278,493	273,135	278,342	283,126
Less Purchase Power and Wheeling expenses	-278,923	-308,702	-328,118	-278,493	-273,135	-278,342	-283,126
Subtotal, 89X5068.01	0	0	0	0	0	0	0
TOTAL, PROPRIETARY RECEIPTS	163,310	234,839	158,717	215,683	170,809	171,454	175,917

Pending Litigation

Pending litigation that may impact Western's FY 2009 Congressional Budget request includes:

- ***California Power Exchange Corp.*, United States Bankruptcy Court, Central District of California, Case No. LA 01-16577-ES**. On March 9, 2001, the California Power Exchange (PX) filed for bankruptcy under Chapter 11 of the Federal Bankruptcy Code. The filing was necessary after the PX had ceased operations on January 31, 2001. The PX could not operate after that date because it was not being paid by Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) for purchases they were making from the PX. Western is owed approximately $6.7 million by the PX. Western has filed a claim in the case and is being represented by bankruptcy counsel from the Department of Justice (DOJ) in Washington, DC. Final settlement of the bankruptcy is complicated due to the interrelationship of this case and many others stemming from the dysfunctional California electricity markets in 2000 and 2001. In order to pay its debts, the PX must ultimately be able to collect significant sums from PG&E and SCE. PG&E was itself in bankruptcy and SCE was in default for most of its obligations. The resolution of PG&E's bankruptcy has assisted in final resolution of the PX's bankruptcy. PG&E has escrowed significant funds to cover its obligations to the PX, as has SCE.

  The PX has a court approved Reorganization Plan. Much of the plan is dependent on certain approvals being made by FERC. Among other issues, FERC must address: the allocation of defaults among participants in the PX markets, the disposition of collateral, the calculation of "refunds" in the "Refund Case" (See FERC Docket Nos. EL00-95-000, et al., below), and the winding up of litigation related to the PX markets.

  Additionally, to wind up its FERC related activities, the Reorganized PX requires funding. In July 2002, the PX made a Section 205 application to FERC for approval of a rate schedule that would permit the PX to charge its participants for their appropriate share of the costs of winding up its operations. FERC approved the rate schedule in August 2002. In July 2004, the Court of Appeals for the DC Circuit struck down the rate, concluding it violated the "filed rate doctrine" and amounted to impermissible retroactive rate making. Settlement proceedings have successfully reached new rates for the PX, with the first settlement filed with FERC on September 1, 2005.

  Additionally, as part of the rate settlement discussed above, California State Court proceedings related to "inverse condemnation" of the "block forward" contracts that were seized by former California Governor Davis immediately following the PX's initial defaults in January 2001 were dismissed. Similarly, litigation against former directors and officers for allegations of malfeasance at the time of the PX's demise in 2001 was dismissed in exchange for cash settlements with the "Director & Officer" insurers. The PX made filings in the appropriate fora to effectuate the settlement.

  By its terms, the settlement discussed above is effective through December 31, 2007. In view of the current status of the refund proceeding (See also FERC Docket No. ER00-95, et al., below), it was very unlikely that PX's work will be concluded before the expiration of the settlement on December 31, 2007. The PX Board of Directors directed PX's management to make plans to extend the effective period of the settlement. There was no opposition to the extension of the settlement. On May 4, 2007, the PX filed the request for the extension in FERC Docket No. ER07-861-000. The filing extends the prior settlement until December 31, 2010. FERC issued a letter order on July 2, 2007.

On November 16, 2007, Enron Power Marketing, Inc. (EPMI) filed an interpleader action in United States Bankruptcy Court for the Southern District of New York asking for resolution of rights the PX and PX participants, including Western, may have in $17.5 million that results from a general unsecured claim the PX filed in the EPMI bankruptcy proceeding. A hearing is set for January 10, 2008.

- ***Quechan Indian Tribe vs. United States*, United States District Court, Southern District of California, Docket No. 02 CV 01096 JH (AJB)**. On June 7, 2002, the Quechan Indian Tribe filed suit in Federal District Court in its own capacity, and as *parens patriae* on behalf of its members, seeking declaratory and injunctive relief and $9.4 million in damages relating to the alleged impact to cultural sites that occurred within the Tribe's Fort Yuma Reservation located in Imperial County, California. The causes of action against Western are for money damages for injury or loss of property caused by the alleged negligent or wrongful acts or omissions of federal employees while acting within the scope of their office or employment when doing work on a project known as the Gila-Knob Pole 161-Kv Wood Pole Rehabilitation Project. The United States filed an Answer on October 22, 2002.

  In July 2003, the Parties applied for and were granted a stay of the present litigation pending a ruling by the United States Supreme Court in a case that addressed whether the Tribe ceded ownership of its reservation in 1893. *See Arizona v. California*, 530 U.S. 392 (2000). A ruling by the Supreme Court could have resulted in the Tribe losing its interest in its Reservation, which would impact nearly all of the Tribe's claims in the present lawsuit. However, the parties settled the Supreme Court litigation. The Solicitor General's office requested comments from Western on the terms of the Supreme Court Settlement and Western formally objected to the language permitting the Tribe to retain all arguments in this case.

  Following the Supreme Court settlement, the United States and the Tribe negotiated, and the Court approved, a Case Management Order that sets forth the following four phased approach: (Phase 1) fact discovery (which was completed on June 10, 2005); (Phase 2) summary judgment motions; (Phase 3) expert discovery; and (Phase 4) pretrial proceedings.

  The Parties are now in Phase 2. The Parties filed Cross Motions for Summary Judgment on September 2, 2005, Responsive Briefs on November 4, 2005, and Reply Briefs on December 9, 2005. Oral argument was held on January 11, 2006, and we are still waiting on a ruling from the U.S. District Court Judge.

- ***California Independent System Operator Corp.*, Docket ER01-313-000 and *Pacific Gas and Electric Company*, Docket No. ER01-424-000 (consolidated), United States Court of Appeals for the District of Columbia, 04-1090, *and Pacific Gas and Electric Company v. United States*, United States Court of Federal Claims, 07-352-C.** In docket ER01-313-000, the California Independent System Operator Corporation (CAISO), tendered for filing an unbundled Grid

Management Charge (GMC) on November 1, 2000. The purpose of the GMC is to allow the CAISO to recover its administrative and operating costs. The CAISO requested that the unbundled GMC be made effective as of January 1, 2001.

In docket ER01-424-000, PG&E tendered for filing a GMC Pass-Through Tariff on November 13, 2000. PG&E alleges that the filing seeks to recover the costs proposed in the CAISO's GMC filing in Docket No. ER01-313-000. PG&E further alleges that it is a new service. PG&E requests an effective date of January 1, 2001, or the date the Commission makes effective the CAISO's filing. In the alternative, PG&E argued it was allowed to modify the existing contracts to pass through the GMC. Western argued that PG&E was not offering a new service for its existing contract customers. Western also argued the GMC was unjust and unreasonable. Finally, Western argued the filing was insufficient.

On December 29, 2000, the Commission consolidated ER01-313-000 with ER01-424-000, accepted the matter for filing and set the matter for evidentiary hearing. Western filed its answering testimony on August 17, 2001. Western filed a motion asking for summary judgment on the issue of whether PG&E could modify Western's existing contracts. The Presiding Judge granted Western's motion. As a result, the only issue at hearing was whether the charges were new services. From November 13, 2001 – December 20, 2001, the Presiding Law Judge heard the case. The Presiding Judge issued her initial decision on May 10, 2002.

The Initial Decision found that the charges for Control Area Service (CAS bucket) constituted a new service to PG&E's Control Area Agreement (CAA) customers, i.e. existing contract holders. The Initial Decision also found that charges for Market Operations (MO bucket) was not a new service for CAAs. Therefore, the Presiding ALJ ordered PG&E to make a compliance filing to reflect the existing charges for market operations under each CAA and those additional ISO MO charges. However, in the case of Western, the Presiding Judge acknowledged her earlier ruling on Summary Judgment that PG&E had not fulfilled its limited Section 205 rights under 2948A.

Western filed a brief on exceptions on June 10, 2002, asserting that the Initial Decision errs in finding that the CAS bucket constitutes a new service and violates Commission precedent. On May 2, 2003, the Commission issued an opinion affirming the Presiding Judge's opinion that the CAS pass through was a new service and reversing the Presiding Judge's finding that the MO component of the GMC was not a new service. On June 2, 2003, Western filed a request for rehearing. On January 23, 2004, the Commission issued an order denying Western's, and other parties', Requests for Rehearing. Western then requested that the Department of Justice seek judicial review of FERC's decision.

The Department of Justice filed a Petition for Review on March 22, 2004. In the meantime, numerous parties filed requests for rehearing on the Commission's Opinion 463-A, 106 FERC ¶61,032 (2004). As a result of these continued administrative proceedings, FERC Staff moved to stay the Circuit Court appeal proceedings and the Circuit Court granted that motion. On January 29, 2007, the Commission issued its final administrative order. As a result, the parties to the D.C. Circuit proceedings moved to lift the stay and negotiated a joint briefing schedule. The Department of Justice recommended Western participate in a joint brief with the other appellants and Western concurred in that recommendation. Final briefs are due on January 18, 2008 and the Court has not yet set a date for oral argument.

In the meantime, PG&E has sent invoices to Western for the GMC charges. Western, however, was unable to verify PG&E's loads on which it was basing the GMC charge. Therefore, Western was unable to pay the invoices. Also, Western's obligation to pay the invoice was dependent on the outcome of Western's D.C. Circuit Court appeal. On December 1, 2005, Western received a revised GMC bill from PG&E. On April 13, 2006, PG&E sent Western a Claim for Damages under the Contract Disputes Act (CDA) seeking $5.5 million for the remaining unpaid balance PG&E alleges Western owes for GMC. On June 12, 2006, Western sent PG&E a letter denying its claim. PG&E had 90 days from the date it received Western's denial to provide notice it intended to pursue an appeal with the agency board of contract appeals. Instead of appealing to the agency board of contract appeals, PG&E had the option of bringing an action directly in the United States Court of Federal Claims within 12 months of the date it received Western's decision. PG&E filed such a claim in the Court of Federal Claims on June 5, 2007 in 07-352-C. Western filed an Answer and Counterclaim on September 5, 2007. PG&E filed an Answer on September 26, 2007. The Parties filed a Joint Preliminary Status Report indicating the case should be stayed pending the D.C. Circuit Court appeal, described above. On November 29, 2007, the Court held a scheduling conference and granted the parties request to stay the case.

Federal Energy Regulatory Commission Litigation

- ***Calpine Construction Finance Co., FERC Docket ER05-912-000***. On December 21, 2005, Calpine Corporation and numerous affiliates filed a Chapter 11 Reorganization with the Federal Bankruptcy Court in the Southern District of New York. Western has numerous contracts with Calpine and is closely monitoring the proceedings. In a typical month, Calpine pays Western over $1 million for transmission service under Western's Open Access Transmission Tariff. Western and Calpine executed an assurance agreement in May 2006. Under this agreement, Calpine will prepay Western 30 days in advance for transactions. Western bills Calpine 20 days in advance. Western filed its proofs of claim in April 2006 for more than $1 million for certain pre-petition transactions. On June 20, 2007, Calpine filed a plan of reorganization. The Department of Justice, in conjunction with Western, is looking over the plan.

- ***San Diego Gas & Electric Company Investigation of Practices of the California Independent System Operator and California Power Exchange, California Electricity Oversight Board, et al.***, **Docket Nos. EL00-95-000, et al.** In the fall of 2000, the Commission began an investigation under Section 206 of the Federal Power Act into the dysfunctional California markets. The Commission has issued a series of orders addressing both price mitigation and potential refunds. The Commission eventually (June 19, 2001) ordered "hard" price caps in the California and WSCC spot markets. The Commission also made a finding that prices charged in the California markets were unjust and unreasonable. Important to Western was a Commission decision to assert jurisdiction over non-public utilities with regard to refunds.

  FERC issued rehearing orders on December 19, 2001, largely upholding the earlier Commission orders in the case, including jurisdiction over non-public utilities. Hearings were first held in March 2002 to calculate the appropriate mitigated market clearing prices and scope of refunds. Subsequent hearings on Issues II and III ("who owes what to whom") were held in August 2002. The Presiding ALJ did preliminarily decide that Western's CRSP "exchange transactions" with the ISO were not subject to refund.

The Presiding ALJ issued his Initial Decision (ID) in December 2002. At approximately the same time, FERC responded to an order of the Ninth Circuit Court of Appeals in August 2002 that found that FERC had not developed an adequate record with respect to the extent of manipulation. FERC allowed an additional discovery period of 100 days. Western responded to over 140 data requests from the "California Parties" and organized a document repository at SNR. In March 2003, the Commission issued an order largely upholding the ID. Following the March 2003 Order, the Commission initiated proceedings to resolve outstanding issues relating to gas prices. These proceedings have continued and Western has worked in particular with the City of Redding regarding the filing of a Fuel Cost Allowance (FCA) claim on behalf of Redding. Notice of the FCA claim was filed with the Commission on April 1, 2005 and also submitted to the auditor, Ernst & Young, at that time. On August 30, 2005, Western submitted Redding's final FCA to the ISO.

In September 2004, the Ninth Circuit ruled against the Commission and found that the Commission did in fact have authority to order refunds for the time period prior to October 2, 2000, based on the theory that certain sellers with market-based rate authority had failed to file required reports of sales with the Commission. The Commission has not yet issued any orders in response to the Ninth Circuit opinion.

The ISO and PX have generally finished conducting "reruns" of the markets for the refund period in order to calculate refunds in accordance with the Commission's current rulings and formulae in the case. In December 2003, SNR and Montrose began receiving the first sets of rerun data for review and possible dispute proceedings. Latest indications from the ISO show it may still be many months before completion, probably not until sometime in 2008. The Commission has attempted to speed up the process in response to Congressional direction in the 2005 Energy Policy Act. The Act called on FERC to attempt to resolve these proceedings by the end of 2005 and to provide Congress a progress report at that time. On August 8, 2005, the Commission issued an order, in part to amend the procedural schedules, in order to meet these new time requirements. That order also set procedures for the submission of revenue shortfall filings. Western evaluated the potential of making cost filings, but under current Commission directives, found that is was not advantageous to do so. The August 8 Order also included provisions for entities to file "final" disputes regarding ISO and PX reruns. Western also evaluated that possibility, but did not file any further disputes. The Commission continues to hear matters related to the cost filings and other offsets.

On September 6, 2005, the Ninth Circuit ruled (in Bonneville v. FERC) that FERC did not have the authority under the Federal Power Act to order refunds from governmental sellers, such as Western, in these proceedings. The ruling was appealed (unsuccessfully) back to the Ninth Circuit and is now on final appeal to the United States Supreme Court. The Supreme Court should indicate by December 2007 whether it will hear the appeal. Until such time as the ruling is final and FERC takes action in accordance with the ruling, Western may still need to participate in continued proceeding in order to preserve procedural rights.

On December 5 and 29, 2005, Western received claims (under the Contract Disputes Act or CDA) from the California Parties in the approximate amount of $30 million. This action was in response to the Ninth Circuit's rejection of FERC's jurisdiction over Western, BPA and other governmental sellers. Because of their setback at the Ninth Circuit, the California Parties have turned to the filing of administrative contractual claims against Western, BPA (under the CDA) and the other governmental sellers (as administrative claims under California State law). The California Parties rely on a portion of the Ninth Circuit's opinion where the Court, while rejecting FERC's authority to order refunds under the FPA, raises the possibility of contract-based actions. The Ninth Circuit cited to FERC and Federal court proceedings to support this possibility. Western requested further information to support the claims. The California Parties refused to provide such information and on March 23, 2006, the claims were denied. In March 2007, the California Parties followed up these administrative claims with law suits in the COFC (See Pacific Gas & Electric Co., Southern California Edison Co., and California Electricity Oversight Board v. US; San Diego Gas & Electric Company v. US; and The People of the State of California, Ex Rel. Edmund G. Brown, Jr., Attorney General of the State of California and the Department of Water Resources by and through its California Energy Resources Scheduling Division v. US, under Federal Courts, above).

In August 2006, the Ninth Circuit issued an opinion in the "Scope Cases" finding that FERC did generally have authority to order refunds for the "Summer 2000" period and for exchange transaction; however, the Ninth Circuit did find that "CERS transactions (bi-lateral sales made to the California Department of Water Resource's - California Energy Resources Scheduling Division)" were not subject to refund. These changes to the scope of the case arguably increase Western's overall refund liability by as much as $6 million, although those numbers have not yet been calculated by FERC. Following this decision, the Ninth Circuit also initiated a new settlement process in these proceedings, with the first settlement conference held in San Francisco on September 19, 2006. A further meeting was held in Pasadena in November between the various municipal sellers (including Western and BPA) and the mediators.

While the Ninth Circuit/Supreme Court proceedings have developed, Western has still engaged in settlement discussions with the California Parties. In February 2007, Western made a counteroffer to the California Parties, who replied with a further counter-offer. Western and Bonneville also met with the California Parties in San Francisco on March 1, 2007, for the purposes of settlement. Settlement discussions have now waned in the face of the COFC filings referred to above; however, the Ninth Circuit did hold another status conference in San Francisco in October 2007.

On April 2, 2007, the California Parties filed a motion with FERC seeking certain procedures to be put in place following the issuance of the Ninth Circuit mandate in <u>Bonneville</u>. The California Parties essentially ask FERC to continue the process of having the ISO rerun the markets for all participants, including governmental entities, which were effectively removed from the case by <u>Bonneville</u>. On April 17, 2007, Western and BPA answered and opposed the California Parties' motion. The California Parties answered that answer on April 30, 2007. Western and BPA further answered on May 14, 2007. Various other parties have weighed in on the issue of the FERC procedures to be implemented following the mandate, and Western and BPA responded to the motion of Pinnacle West on May 18, 2007. During this period, Western also filed comments on April 19, 2007, opposing the ISO's authority for making certain interest adjustments during the Refund Period and also on that same day opted out of the El Paso Marketing LP settlement. On October 19, 2007, FERC took action on the *Bonneville* mandate and issued an order confirming that governmental entities' sales are not subject to refund and ordering that collateral and receivables be paid out to the governmental entities, including Western. The order also, importantly, stated that FERC had not "reset" prices in the ISO and PX markets. This finding was important because it severely undercut arguments the California Parties were making in the contract claims litigation, including those claims against BPA and Western in the COFC. The California Parties immediately sought clarification of FERC's order and on November 19, 2007, FERC reversed the October 19, 2007, order and said it had misspoken on the issue of "resetting" of the markets and now said that it had, in fact, reset the markets. Western, BPA and the other governmental entities sought rehearing of FERC's November 19, 2007, order. Additionally, of interest, on December 10, 2007, the Supreme Court denied certiorari of PG&E's request to have the Ninth Circuit's *Bonneville* opinion overturned.

Bonneville Power Administration

Bonneville Power Administration

Bonneville Power Administration

Proposed Appropriations Language

Expenditures from the Bonneville Power Administration Fund, established pursuant to Public Law 93-454, are approved for[the Lower Granite Dam fish trap, the Kootenai River White Sturgeon Hatchery, the Nez Perce Tribal Hatchery, Redfish Lake Sockeye Captive Brood expansion, hatchery production facilities to supplement Chinook salmon below Chief Joseph Dam in Washington, Hood River Production Facility, Klickitat production expansion, Mid Columbia Coho restoration, and Yakama Coho restoration, and, in addition, for] official reception and representation expenses in an amount not to exceed $1,500.

During fiscal year [2008]*2009*, no new direct loan obligations may be made.

Explanation of Changes

The proposed appropriations language restricts new direct loans in FY 2009 as in FY 2008

Bonneville Power Administration

Overview

Summary by Program

(accrued expenditures in thousands of dollars)

	FY 2007	FY 2008	FY 2009
Capital Investments			
Power Services	150,492	236,675	215,330
Transmission Services	140,965	242,370	293,533
Capital Equipment & Bond Premium	20,610	31,017	51,123
Total, Capital Investments	312,067	510,062	559,986
Accrued expenditures will require budget obligations of	312,067	510,062	559,986
Operating Expenses	2,349,791	2,718,980	2,865,884
Projects Funded in Advance	107,269	71,775	125,318
Capital Transfers (cash)	623,400	408,264	275,723
BPA Net Outlays	(508,000)	42,000	23,000
BPA Staffing (FTE)	2,896	3,000	3,000

Outyear Summary

(accrued expenditures in thousands of dollars)

	FY 2010	FY 2011	FY 2012	FY 2013
CAPITAL INVESTMENTS				
Power Services	219,325	224,314	234,236	239,181
Transmission Services	278,184	369,836	419,059	319,631
Capital Equipment & Bond Premium	54,798	28,363	28,431	29,501
Total, Capital Investments	552,307	622,513	681,726	588,313
Accrued expenditures will require budget obligations of	552,307	622,513	681,726	588,313
Operating Expenses	2,695,594	2,789,216	2,708,184	2,667,493
Projects Funded in Advance	65,856	78,966	72,242	72,603
Capital Transfers (cash)	423,976	417,680	293,841	246,661
BPA Net Outlays	30,000	17,000	(4,000)	(10,000)
BPA Staffing (FTE)	3,000	3,000	3,000	3,000

Overview

The accompanying notes are an integral part of this table.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that, along with actual market conditions, will impact revenues and expenses. Actual Net Outlays are volatile and are reported in SF-133. Estimated Net Outlays could change due to changing market conditions, streamflow variability, and continuing restructuring of the electric industry.

Revenues, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools, including upcoming rate adjustment mechanisms, a net revenue risk adjustment, debt service refinancing strategies and/or short-term financial tools to manage net revenues and cash. Some of these potential tools will reduce costs rather than generate revenue, causing the same Net Outlay result. Adjustments for depreciation and 4(h)(10)(C) credits of the NW Power Act are also assumed.

The cumulative amount of actual advance amortization payments as of the end of FY 2007 is $2,091 million.

FTE outyear data are estimates and may change.

Preface

The Bonneville Power Administration (Bonneville or BPA) serves the Pacific Northwest through operating an extensive electricity transmission system and marketing wholesale electrical power at cost from Federal dams and other non-Federal generating units including some wind energy generation facilities.

The organization of Bonneville's FY 2009 budget reflects Bonneville's business services basis for utility enterprise activities. Bonneville's two major areas of activity on a consolidated budget and accounting basis include Power Services (PS) and Transmission Services (TS) with administrative costs included. The PS includes line items for Fish and Wildlife, Conservation and Energy Efficiency, Residential Exchange Program (REP), Associated Projects O&M Costs, and Northwest Power and Conservation Council (Planning Council, Council).

Mission

The strategic mission of Bonneville as a public service organization is to create and deliver the best value for its customers and constituents as it acts in concert with others to assure the Pacific Northwest:

- An adequate, efficient, economical and reliable power supply;
- A transmission system that is adequate to the task of integrating and transmitting power from Federal and non-Federal generating units, providing service to BPA's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and
- Mitigation of the Federal Columbia River Power System (FCRPS) impacts on fish and wildlife.

As BPA shapes programs and plans spending levels, it is driven by its strategic vision that encompasses the following four pillars:

- High reliability;
- Low rates consistent with sound business principles;
- Responsible environmental stewardship; and
- Accountability to the region.

Bonneville is committed to cost-based rates and public and regional preference in its marketing of power. Bonneville will set its rates as low as possible consistent with sound business principles and the full recovery of all of its costs, including timely repayment of the Federal investment in the system.

Benefits

Bonneville provides electric power (about one third of the electricity consumed in the region), transmission (about three-fourths of the region's high voltage transmission capacity), and energy efficiency throughout the Pacific Northwest, a 300,000 square mile service area. Bonneville markets the electric power produced from 31 operating Federal hydro projects in the Pacific Northwest owned by the U.S. Corps of Engineers (Corps) and the U.S. Department of Interior, Bureau of Reclamation (Reclamation), and also acquires non-Federal power, including the power from the Columbia Generating Station (CGS), to meet the needs of its customer utilities. Bonneville owns and operates over 15,000 circuit miles of lines, 237 substations and associated power system control and communications facilities over which this electric power is delivered. Bonneville also supports the protection and enhancement of fish and wildlife, and provides leadership in conservation and renewables development, as part of its efforts to preserve and balance the economic and environmental benefits of the FCRPS.

Bonneville's strategic direction establishes the agency's most important long-term objectives and the actions that will help it manage to these objectives. The strategic direction calls on BPA to advance the Pacific Northwest's future leadership in three core values: trustworthy stewardship of the FCRPS, collaborative relationships, and operational excellence.

Strategic Themes and Goals and GRPA Unit Program Goals

The Department of Energy's (Department or DOE) Strategic Plan identifies five Strategic Themes (one each for nuclear, energy science, management, and environmental aspects of the mission plus sixteen Strategic Goals that tie to the Strategic Themes). The Bonneville program supports the following goal:

Strategic Theme 1, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

Strategic Goal 1.3 Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

Bonneville's Government and Results Performance Act (GRPA) Unit Program Goal contributes to the Strategic Goals in the "goal cascade." This goal is to Market and Deliver Federal Power:

GRPA Unit Program Goal 01.03.18.00: Bonneville Power Administration. Market and Deliver Federal Power: Ensure Federal hydropower is marketed and delivered while passing the North American Electric Reliability Council's (NERC) Control Compliance Ratings, meeting planned repayment targets, and achieving targeted hydropower generation efficiency performance.

Contribution to Strategic Goal

Bonneville contributes to this strategic goal through its strategic vision to advance a Northwest power system that is a national leader in providing reliability, low rates consistent with sound business principles, environmental stewardship, and accountability to the region. BPA is continuing its emphasis on performance with 27 agency-wide long-term objectives for FYs 2008-2014 that are key to achieving its mission. These objectives, aligned using the balanced scorecard model, are focused on stakeholder value, financial performance, internal operations, and people and culture. Bonneville's infrastructure investments in the Pacific Northwest to meet power and transmission needs continue to support DOE's strategic goal on energy infrastructure.

Bonneville's strategic direction has helped to identify a number of key long-term issues. These issues center on providing Bonneville customers with certainty over load service obligations and enabling customers and the market to respond with the necessary electric industry infrastructure investments. Other key strategic interests include general market stability, BPA risk management, and long-term assurance of funding to repay the U.S. Treasury (Treasury) investment in infrastructure. Bonneville is now addressing these key issues through the Regional Dialogue, BPA's post-2011 power marketing planning process.

Funding by Strategic and GRPA Unit Program Goal

	(accrued expenditures in thousands of dollars)		
	FY 2007	FY 2008	FY 2009
Strategic Theme 1, Energy Security			
Strategic Goal 1.3 Energy Infrastructure			
GRPA Unit Program Goal 01.03.18.00, Market and Deliver Federal Power			
Bonneville Power Administration			
Capital Investments			
Power Services	150,492	236,675	215,330
Transmission Services	140,965	242,370	293,533
Capital Equipment & Bond Premium	20,610	31,017	51,123
Total Capital Investments	312,067	510,062	559,986
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BPA Staffing (FTE)	2,896	3,000	3,000

Outyear Funding by Strategic and GRPA Unit Program Goal

	(accrued expenditures in thousands of dollars)			
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Strategic Theme 1, Energy Security				
Strategic Goal 1.3 Energy Infrastructure				
GRPA Unit Program Goal 01.03.18.00, Market and Deliver Federal Power				
Capital Investments				
Power Services	219,325	224,314	234,236	239,181
Transmission Services	278,184	369,836	419,059	319,631
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Total Capital Investments	552,307	622,513	681,726	588,313
Accrued expenditures will require budget obligations of	552,307	622,513	681,726	588,313

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Operating Expenses	2,695,594	2,789,216	2,708,184	2,667,493
Projects Funded in Advance	65,856	78,966	72,242	72,603
Capital Transfers (cash)	423,976	417,680	293,841	246,661
Net Outlays	30,000	17,000	(4,000)	(10,000)
BPA Staffing (FTE)	3,000	3,000	3,000	3,000

Funding by General and Program Goal

The accompanying notes are an integral part of this table.

Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that, along with actual market conditions, will impact revenues and expenses. Actual Net Outlays are volatile and are reported in SF-133. Estimated Net Outlays could change due to changing market conditions, streamflow variability, and continuing restructuring of the electric industry.

Revenues, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools, including upcoming rate adjustment mechanisms, a net revenue risk adjustment, debt service refinancing strategies and/or short-term financial tools to manage net revenues and cash. Some of these potential tools will reduce costs rather than generate revenue, causing the same Net Outlay result. Adjustments for depreciation and 4(h)(10)(C) credits of the NW Power Act are also assumed.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

FTE outyear data are estimates and may change.

Annual Performance Results and Targets

FY 2004 Results	FY 2005 Results	FY 2006 Targets	FY 2007 Targets	FY 2008 Targets	FY 2009 Targets	
Strategic Goal.3.1, Energy I						
System Reliability Performance: Met Goal Actual: CPS1: 198.5% CPS2: 94.3%	System Reliability Performance: Met Goal Actual: CPS1: 196.6% CPS2: 93.9%	System Reliability Performance: Met Goal Actual: CPS1: 193.3% CPS2: 96.1%	System Reliability Performance: Met Goal Actual: CPS1: 193.9% CPS2: 96.01%	System Reliability Performance: Attain average North American Reliability Council (NERC) compliance ratings for the following NERC Control Performance Standards (CPS) measuring the balance between power generation and load, including support for system frequency: (1) CPS1, which measures generation/load balance on one-minute intervals (rating > or =100); and (2) CPS2, which limits any imbalance magnitude to acceptable levels (rating > or =90).	System Reliability Performance: Attain average North American Reliability Council (NERC) compliance ratings for the following NERC Control Performance Standards (CPS) measuring the balance between power generation and load, including support for system frequency: (1) CPS1, which measures generation/load balance on one-minute intervals (rating > or =100); and (2) CPS2, which limits any imbalance magnitude to acceptable levels (rating > or =90).	
Repayment of Federal Power Investment Performance: Met Goal ($246 million) Actual: $592 million	Repayment of Federal Power Investment Performance: Met Goal ($303 million) Actual: $618 million	Repayment of Federal Power Investment Performance: Met Goal ($304 million) Actual: $646 million	Repayment of Federal Power Investment Performance: Met Goal ($387 million) Actual: $618 million	Repayment of Federal Power Investment Performance: Meet planned annual repayment of principal on Federal power investments.	Repayment of Federal Power Investment Performance: Meet planned annual repayment of principal on Federal power investments.	
	Hydropower Generation Efficiency Performance: Met Goal (97%) Actual: 100% (EOY)	Hydropower Generation Efficiency Performance: Met Goal (97%) Actual: 100% (EOY)	Hydropower Generation Efficiency Performance: Met Goal (97%) Actual: 99.6% (cumulative for the four quarters of FY 2007)	Hydropower Generation Efficiency Performance: Achieve > or = 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Army Corps of Engineers, and Bureau of Reclamation. HLHA is actual machine capacity available during heavy-load hours (0700-2200 Monday-Saturday), divided by planned available capacity during heavy-load hours.	Hydropower Generation Efficiency Performance: Achieve > or = 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Army Corps of Engineers, and Bureau of Reclamation. HLHA is actual machine capacity available during heavy-load hours (0700-2200 Monday-Saturday), divided by planned available capacity during heavy-load hours.	

Annual Outyear Performance Targets

FY 2010 Targets	FY 2011Targets	FY 2012 Targets	FY 2013Targets
Strategic Goal.3.1, Energy Infrastructure			
System Reliability Performance: Attain average NERC compliance ratings for the NERC CPS measuring the balance between power generation and load, including support for system frequency.	System Reliability Performance: Attain average NERC compliance ratings for the NERC CPS measuring the balance between power generation and load, including support for system frequency.	System Reliability Performance: Attain average NERC compliance ratings for the NERC CPS measuring the balance between power generation and load, including support for system frequency.	System Reliability Performance: Attain average NERC compliance ratings for the NERC CPS measuring the balance between power generation and load, including support for system frequency.
Repayment of Federal Power Investment Performance: Meet planned annual repayment of principal on Federal power investments.	Repayment of Federal Power Investment Performance: Meet planned annual repayment of principal on Federal power investments.	Repayment of Federal Power Investment Performance: Meet planned annual repayment of principal on Federal power investments.	Repayment of Federal Power Investment Performance: Meet planned annual repayment of principal on Federal power investments.
Hydropower Generation Efficiency Performance: Achieve > or = 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Army Corps of Engineers, and Bureau of Reclamation. HLHA is actual machine capacity available during heavy-load hours (0700-2200 Monday-Saturday), divided by planned available capacity during heavy-load hours.	Hydropower Generation Efficiency Performance: Achieve > or = 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Army Corps of Engineers, and Bureau of Reclamation. HLHA is actual machine capacity available during heavy-load hours (0700-2200 Monday-Saturday), divided by planned available capacity during heavy-load hours.	Hydropower Generation Efficiency Performance: Achieve > or = 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Army Corps of Engineers, and Bureau of Reclamation. HLHA is actual machine capacity available during heavy-load hours (0700-2200 Monday-Saturday), divided by planned available capacity during heavy-load hours.	Hydropower Generation Efficiency Performance: Achieve > or = 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Army Corps of Engineers, and Bureau of Reclamation. HLHA is actual machine capacity available during heavy-load hours (0700-2200 Monday-Saturday), divided by planned available capacity during heavy-load hours.

BPA is continuing to assess target measures that achieve the best alignment with its strategic objectives.

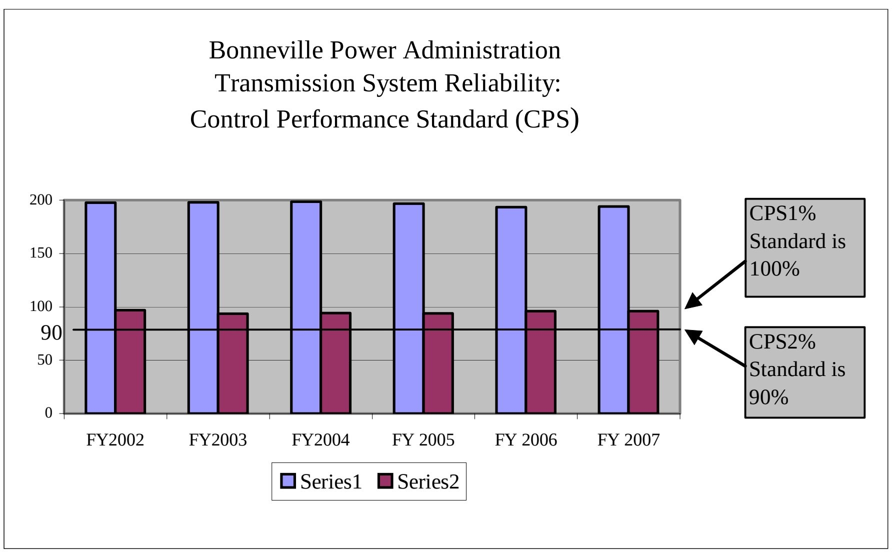
The Hydropower Generation Efficiency Performance Target is included in this FY 2009 budget as a performance measure starting in FY 2005. For FY 2004, the goal for this measure was 97% with actual results of 100%.

Transmission System Reliability Performance Indicator

This indicator defines a standard of minimum monthly control performance as established by the NERC. Each control area within the system is to operate above minimum monthly control compliance ratings that can be achieved within the bounds of reasonable economic and physical limitations. Each control area is to monitor its control performance continuously against two standards, CPS 1 and 2.

The CPS-1 and CPS-2 performance indicators are industry standards that U.S. and Canadian electric utilities use in conjunction with NERC to help assure the reliability of the North American high voltage distribution system, and thereby to benefit the public. These measures are intended to indicate whether or not electric utility systems are being operated within acceptable operating parameters. Any deviation from the minimum standards must be reported to NERC. CPS-1 helps assure generation and load balance. CPS-2 helps limit the magnitude of any imbalance to acceptable levels, and provides a frequency sensitive evaluation of how well a control area meets its demand requirements.

Transmission System Reliability Target in FY 2009: Attain average NERC compliance ratings for the following NERC CPS measuring the balance between power generation and load, including support for system frequency: (1) CPS-1, which measures generation/load balance on one-minute intervals (rating >=100); and (2) CPS-2, which limits any imbalance magnitude to acceptable levels (rating >=90).



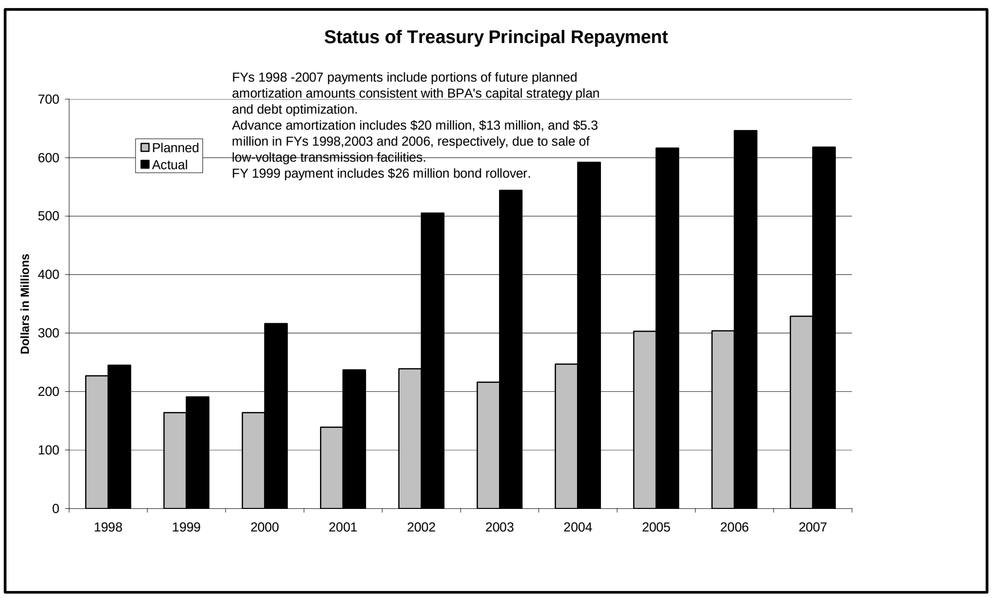
Repayment of Federal Power Investment Performance Indicator

This indicator measures the variance of actual from planned principal payments to the Treasury.

Treasury payment outyear estimates for planned amortization of principal are based on rate case estimates when available and planned amortization for future rate case periods. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and advanced amortization payments. In recent years, BPA has made amortization payments in excess of those scheduled in its Federal Energy Regulatory Commission (FERC)-approved rate filings, resulting in a balance of advance repayment. Bonneville made its full FY 2007 payment of $1,045 million to the Treasury comprised of $618 million in amortization that includes $289 million in advanced amortization, $395 million in interest, and $32 million of unfunded CSRS liabilities and other costs.

> Repayment target in 2009 – Meet planned repayment of principal on Federal power investments in FY 2009.

The following chart displays principal repayment only.



For FY 2007, the planned repayment of principal of Federal power investment reflects the amount calculated in the most recent Power Rate Case that was scheduled to be the lowest level of amortization satisfying the repayment requirements. This display of planned repayment of principal is consistent with all prior years shown on the table. The most recent Power Rate Case also included some amount of advanced repayment of principal to the U.S. Treasury that resulted from the way the debt optimization program was designed to repay a relatively small portion of the Energy Northwest debt.

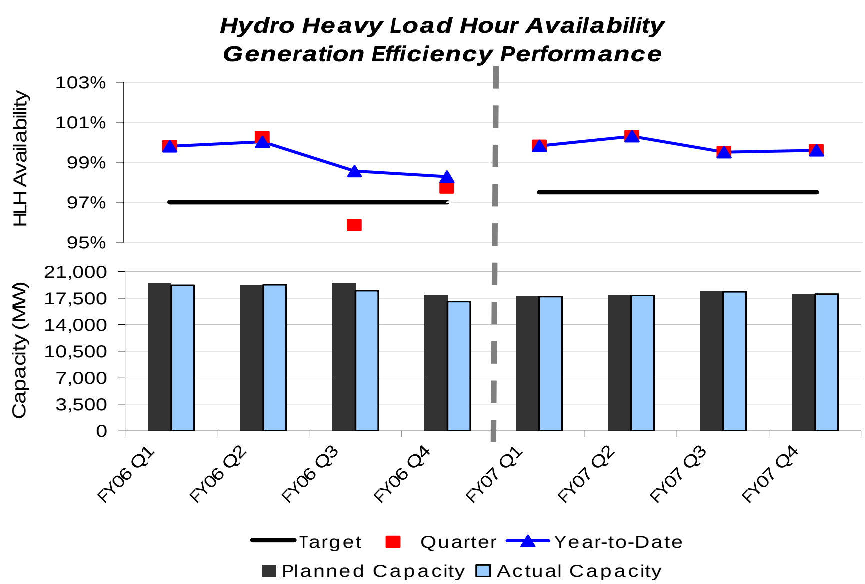
Hydropower Generation Efficiency Performance Indicator

The fundamental programmatic role of Bonneville within the FCRPS is the marketing of electricity generated at the multi-purpose hydro projects owned and operated by the Corps and Reclamation in the Pacific Northwest. HLHA concerns the actual effective performance of the hydroelectric generating system, reflecting joint work between BPA, the Corps, and Reclamation to optimize the operational performance of these generating projects to ensure they are available when they are needed most for meeting the region's firm power loads. It is important from a reliability and economic standpoint to have power generation available when loads are high.

HLHA is the ratio of actual available machine capacity during heavy load hours, divided by planned available capacity during heavy load hours, expressed as a percent.

Actual available machine capacity is measured directly from data supplied from the hydroelectric generating facilities. Planned available capacity is established annually through the Annual Outage planning process, then updated quarterly based on changes in load, water forecasts, and work activities at the plants. The resulting outage plans are stored in BPA's Outage Database.

> Hydropower Generation Efficiency target: Achieve actual efficiency results at or above planned availability target levels for hydropower generation efficiency.



As represented above, FCRPS hydro generating performance tracked very closely to the HLHA targets for all of FY2007, meeting the target in all four quarters.

Means and Strategies

Bonneville provides electric power, transmission, and energy services while supporting the achievement of its vital responsibilities for fish and wildlife, energy conservation, renewable resources, and low-cost power in the Pacific Northwest.

BPA's strategic direction and balanced scorecard establish a key objective of meeting electricity availability, adequacy, reliability, and cost-effectiveness standards through performance and expansion of the transmission system. The strategic direction and balanced scorecard efforts include a long-term vision of Bonneville's future and an assessment of critical environment factors and key objectives. The vision and assessment help direct Bonneville activities needed to meet its mission over the long-term. The objectives are supported by multi-year targets to lay out the long-term course for achieving the objectives.

To improve system adequacy, reliability and availability, BPA has embarked on major transmission infrastructure projects. The projects shore up the region's transmission system and help meet the region's future power needs. These projects address multiple challenges, such as the need to relieve a number of congested transmission paths, the pressure to keep up with growing energy demands, and the need to meet FERC's open access policy in support of competitive markets.

For FY 2009 BPA's total transmission capital budget includes a total of $419 million for main grid additions, upgrades and additions, system replacements, area and customer services, and projects funded in advance. These investments, repaid entirely by revenues from BPA's transmission customers or benefiting third parties, are foundational to BPA's transmission performance.

As part of BPA's strategic direction, Bonneville is also working to improve efficiency and initiate further cost reductions. Bonneville coordinates its power operational activities with the Corps, Reclamation, NERC, regional electric reliability councils, its customers, and other stakeholders to provide the most efficient use of Federal assets. Ongoing work with the Corps and Reclamation is focused on improving the reliability of the FCRPS, increasing its generation efficiency and optimization of hydro facility operation.

In addition, Bonneville is committed to continue funding efforts to recover listed fish and wildlife species in the Columbia Basin under the Endangered Species Act (ESA) and to work closely with the Council, regional fisheries managers, and other Federal agencies to prioritize and manage fish and wildlife program projects.

Bonneville initiatives are impacted by external factors such as continually changing economic and institutional conditions in the electric utility industry, competitive dynamics, and the continued restructuring of the electric industry.

Private and public sector partners have been and continue to be an important part of BPA's collaborative efforts to promote and foster efficient use of energy. BPA has initiated efforts to explore non-Federal financial participation in its transmission infrastructure projects with transmission customers and others in the region. The most recent BPA power rate setting process supported a high level of cooperation and collaboration with customers and other rate case parties resulting in significant cost efficiencies and enhanced risk management approaches. Additionally, BPA is partnering with and assisting a DOE Wind Power crosscutting initiative to strengthen energy security by adding alternative sources of renewable energy.

Additional activities and products contributing to BPA's long-term achievement of its mission include the Regional Dialogue, an enhanced capital asset management plan, a workforce plan that addresses the long-term staffing needs of the agency, and continuing efforts to increase operational efficiencies. A separate Innovative Technology office within BPA leads the long-term strategy development and management for research, development, demonstration and deployment of new technology by BPA. BPA is also working to incorporate the numerous aspects of the Energy Policy Act of 2005 related to its business, in particular transmission reliability, energy supply, conservation, and new energy technologies for the future.

Validation and Verification

To validate and verify program performance, Bonneville conducts various internal and external reviews and audits. Bonneville's programmatic activities are subject to review by Congress, the General Accountability Office (GAO), the Department's Inspector General, and other governmental entities. Bonneville accounts are reviewed annually by an independent outside auditor. In addition, BPA uses Institute of Electrical and Electronics Engineers standard measures to monitor and evaluate system reliability performance, and participates yearly in an independent reliability benchmarking study.

Program Assessment Rating Tool (PART)

The Department implemented a tool to evaluate selected programs. PART was developed by the Office of Management and Budget (OMB) to provide a standardized way to assess the effectiveness of the Federal government's portfolio of programs. The structured framework of the PART provides a means through which programs can assess their activities differently than through traditional reviews.

The current focus is to establish outcome- and output-oriented goals, the successful completion of which will lead to benefits to the public, such as increased national security and energy security, and improved environmental conditions. BPA has incorporated feedback from OMB into the FY 2009 budget submission, and will take the necessary steps to continue to improve performance.

In the 2004 PART review by OMB, Bonneville received high scores of 89 and 100 in the Planning and Management sections. These high scores reflect Bonneville's strong program management system and internal and external program and management reviews. Bonneville's somewhat lower scores in the Purpose and Results sections were attributed in part to its rate setting processes and the need for improved performance measures. Enactment of the adjustable BPA power rates to accommodate changing water conditions and financial performance is an example of how BPA is working to continuously improve its rate setting as a tool to protect the taxpayer's investment in the FCRPS. This rate adjustment helped BPA establish its rates with a targeted Treasury payment probability over 90 percent for the FY 2007-2009 rate period. BPA's FY 2007 Treasury payment marks the 24th consecutive year that BPA has made its payment on time and in full.

Regarding PART feedback on performance measurement, BPA annually reviews its overall strategic vision and associated performance measures, enhancing the linkage between its financial performance and strategy.

With respect to the marketing and cost recovery findings, BPA has initiated a multi-year, agencywide efficiency drive—the Enterprise Process Improvement Program (EPIP). The EPIP has already led to consolidation and centralization of several agency functions, elimination of redundancies and establishment of consistent processes. The resulting transition from a business line basis of organization to a services structure is reflected in this FY 2009 budget. The second phase of the EPIP program is focusing on asset management, marketing and sales, and the materials supply chain. Each EPIP area of focus undergoes an assessment of the current state, benchmarking to identify best practices, designing of the desired future state, and conducting gap analysis to determine changes needed.

Program Perspectives

This section provides an introduction to Bonneville operations and statutory authorities followed by a description of ongoing activities.

Introduction:

Bonneville is DOE's electric Power Marketing Administration for the FCRPS. Bonneville provides electric power, transmission, and energy efficiency throughout the Pacific Northwest. Created in 1937 to market and transmit the power produced by the Bonneville Dam on the Columbia River, Congress has since directed Bonneville to sell at wholesale the electrical power produced from 31 operating Federal hydro projects and to acquire non-Federal power and conservation resources sufficient to meet the needs of Bonneville's customer utilities. Bonneville also owns and operates over 15,000 miles of high-voltage transmission lines, transmitting power from the dams and other sources on an open-access non-discriminatory basis. Bonneville serves a 300,000 square mile area including Oregon, Washington, Idaho, Western Montana, and parts of Northern California, Nevada, Utah, and Wyoming.

The Bonneville Project Act of 1937 provided the foundation for Bonneville's statutory utility responsibilities and authorities. In 1974, passage of the Federal Columbia River Transmission System Act (Transmission System Act) placed Bonneville under provisions of the Government Corporation Control Act (31 U.S.C. 9101-9110). The legislation provided Bonneville with "self-financing" authority and established the Bonneville Fund, a permanent, indefinite appropriation, allowing Bonneville to use its revenues from electric power and transmission ratepayers to directly fund all programs and to sell bonds to the Treasury to finance the region's high-voltage electric transmission system requirements. In 1980, enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) expanded Bonneville's utility obligations and responsibilities to encourage electric energy conservation; develop renewable energy resources; and protect, mitigate and enhance the fish and wildlife of the Columbia River and its tributaries. In support of these responsibilities, Bonneville's Treasury borrowing authority was expanded to allow the sale of bonds to finance conservation and other resources and to carry out fish and wildlife capital improvements. The Northwest Power Act also required regional energy plans and programs and created the Pacific Northwest Electric Power and Conservation Planning Council, now commonly called the Northwest Power and Conservation Council.

Bonneville's program is treated as mandatory and nondiscretionary. As such, Bonneville is "self-financed" by the ratepayers of the Pacific Northwest and is not annually appropriated by Congress. Under the Transmission System Act, Bonneville funds the expense portion of its budget and repays the Federal investment with revenues from electric power and transmission rates. Bonneville's revenues fluctuate primarily in response to market prices for fuels and stream flow variations in the Columbia River System due to weather conditions and fish recovery needs. Bonneville's permanent statutory borrowing authority authorizes the agency to sell bonds to the Treasury up to a cumulative total of $4.45 billion outstanding at any one time. Through FY 2007, Bonneville has returned approximately $23.7 billion to the Treasury for payment of FCRPS O&M and other costs (about $3.0 billion), interest (about $12.2 billion), and amortization (about $8.5 billion) of appropriations and bonds.

Treasury Payments and Budget Overview:

Bonneville made its full planned FY 2007 payment of $1,045 million to the Treasury, including $289 million in advanced amortization (as part of BPA's debt optimization program). Total FY 2007 4(h)(10)(C) credits applied to the Treasury payment for fish mitigation were about $71 million. For FY 2008, Bonneville plans to pay the Treasury $774 million: $408 million to repay investment principal, $348 million for interest, and $18 million for Associated Project costs and pension and post-retirement benefits. The FY 2009 Treasury payment is currently estimated at $673 million. FYs 2008 and 2009 4(h)(10)(C) credits, associated with fish recovery and to be applied toward BPA's Treasury payment, are estimated at $85 million annually, consistent with power rate case documentation.

Estimates of interest levels for outyear Treasury payments are based on FY 2007 Power Rate Case estimates and TS's FY 2008 Rate Case estimates updated to reflect current capital estimates. Bond and Appropriations Interest will continue to be revised based on upcoming capital investments and debt management actions. Amortization estimates are based on existing rate case plans and estimated amortization for future rate case periods. These estimates may change due to revised capital investment plans and actual Treasury borrowing. In recent years, BPA has made amortization payments in excess of those scheduled in its FERC-approved rate filings resulting in a balance of advance repayment. The cumulative amount of advance amortization payments as of the end of FY 2007 is about $2,091 million. Amortization estimates in this FY 2009 budget include planned amortization amounts in advance of scheduled amortization (due to earlier Energy Northwest [EN] refinancing) in FYs 2008 and 2009 of $63 million and $78 million, respectively, consistent with power rate case documentation.

Starting in FY 1997, Bonneville began direct funding the Reclamation's Pacific Northwest power O&M costs, and in FY 1999 Bonneville began direct funding Corps Pacific Northwest power O&M costs. Bonneville began direct funding the U.S. Fish and Wildlife Service (USFWS) in FY 2001 to pay for O&M costs of the Lower Snake River Compensation Plan facilities. Bonneville's direct funding arrangement includes a portion of power O&M capital investments. Direct funded capital costs, previously funded through appropriations, are now being paid through BPA borrowing from the Treasury. BPA's total O&M direct funding, including the small capital program, was $244 million in FY 2007.

This FY 2009 budget proposes Bonneville accrued expenditures of $2,865 million for operating expenses, $125 million for Projects Funded in Advance, $560 million for capital investments, and $276 million for capital transfers in FY 2009. The budget has been prepared on the basis of Bonneville's major areas of activity, power and transmission. This business structure arose as a response to FERC Orders 888 and 889 requiring separation of public utilities' power and transmission functions. As a Federal agency, Bonneville is not subject to FERC's jurisdiction (except for the new requirements of the Energy Policy Act of 2005) but chooses to voluntarily comply with FERC open-access policy. Further, Bonneville supports DOE's October 1995 "Power Marketing Administration Open Access Policy" which states the Power Marketing Administrations' commitment to offer transmission services to eligible entities in a manner comparable to the services offered by FERC-jurisdictional transmission providers to the extent not otherwise inconsistent with Federal law.

Spending levels in this budget are still subject to change to accommodate competitive dynamics in the region's energy markets, debt optimization strategies, and the continued restructuring of the electric industry.

Current Financial Status

- Bonneville's FY 2009 budget reflects the significant financial and business events that have shaped Bonneville's response to the physical and competitive pressures of the region's electricity environment. BPA is striving to enhance its competitive, cost-effective delivery of utility products and services and continued delivery of the public benefits of its operations, while ensuring its ability to make its payments to the Treasury on time and in full. BPA utilizes a strategic planning process using the balanced scorecard model to align all business units around specific goals and align resources to achieve these goals. Additionally, BPA continues to recognize PART feedback from OMB in the areas of planning, performance measurement, and results and marketing. From these efforts, results include continued efficiency gains, performance integration improvements, and a high assurance for repayment of Treasury borrowing.

- After several years of sustained effort, BPA has recovered from the financial effects of the 2000-2001 west coast power crisis. FY 2007 financial results were strong despite a below average water year. Continued cost management efforts helped BPA end FY 2007 with strong reserve levels. These gains are helping BPA continue its efforts to assure full recovery of its costs and to assure long-term financial stability while meeting its overall responsibilities to the Pacific Northwest and the U.S. taxpayer. BPA is well positioned as it moves through the FY 2007-2009 power rate period.

- BPA conducted an extensive consultation process with stakeholders on its power cost structure for the 2007 through 2009 power rate period. This process, called a Power Function Review (PFR), gave the region the opportunity to examine and provide input on the cost projections that formed the basis for BPA's 2007-2009 power rates. The PFR helped BPA identify total estimated rate period savings forecasted to be $122 million per year. BPA submitted its FYs 2007-2009 power rate to FERC and on September 21, 2006 received interim approval of the new rates that took effect October 1, 2006.

- In anticipation of establishing transmission rates for the FY 2008-2009 period, BPA initiated Programs in Review (PIR), a separate public process with customers, constituents and others designed to share proposed transmission program funding levels. Results from the PIR process served as the basis for development of costs in BPA's final 2008 transmission rate proposal and Record of Decision issued in April 2007. The Record of Decision establishes transmission and ancillary services rates for FYs 2008 and 2009 and results in no overall rate increase for the rate period. BPA submitted its transmission rates to FERC for approval in May 2007 and received final approval in September 2007.

- By 2008, BPA intends to align its transmission and power rate cases and consolidate its public processes on agency wide expenses and capital plans as part of its efforts to increase transparency for customers and stakeholders.

- Bonneville released its Long-Term Regional Dialogue Policy and Record of Decision in July 2007. The Regional Dialogue Policy is focused on defining how Bonneville will market its wholesale power after 2011 and to ensure it does so in a way that meets key regional and national energy goals and ensures BPA's ability to meet its Treasury obligations.

  In the Regional Dialogue Policy, BPA committed to updating its Financial Plan. BPA is planning to update the current 10-year Financial Plan in 2008 to reflect current policies and strategies as well as those for the future.

Infrastructure Investment:

- Bonneville is planning infrastructure investments in the Pacific Northwest to meet Northwest transmission needs that will also continue to support a competitive wholesale market in the Western Interconnection that encompasses 14 western States, two Canadian provinces and one Mexican State. These efforts will help to buffer against escalating fossil fuel prices. BPA continues to target transmission investments in those areas with reliability needs.

- Bonneville has identified a number of actions that it is taking or could take over the next several years to provide additional electric system infrastructure relief. These actions include Federal hydro generation efficiencies and additions, additional renewable resource generation and conservation efforts, long-term and short-term power purchases, and construction of transmission projects that reinforce the grid and integrate new generation. As part of these efforts, Bonneville is implementing a process to review and approve certain proposed FCRPS investments.

- Bonneville received an additional $700 million in available Treasury financing through the FY 2003 Appropriations Act to help assure a sufficient level of infrastructure planning. For efficient use of this newly available Treasury financing, BPA will encourage private-sector or other non-Federal financing or joint financing of transmission line expansions and additions, develop a five-year investment plan with the participation of the regional Infrastructure Technical Review Committee or its successor in the region, continue to use funds only for authorized purposes, continue to include the proposed use of the funds in its annual budget submissions and select projects based on cost-effectiveness criteria for achieving the objective. The FY 2003 Appropriations Act increases to $4.45 billion the aggregate amount of bonds Bonneville is authorized by statute to sell to the Treasury and have outstanding at any one time.

- Bonneville considers other strategies to sustain funding for its infrastructure investment requirements as well. These additional strategies include restructuring of EN debt, reserve financing of some amount of transmission investments, and seeking, when feasible, third party financing sources. See the BP-5 Potential Third Party Financing Transparency table in the budget schedules section of this budget. This FY 2009 budget assumes $15 million of annual reserve financing in FYs 2008-2009 for transmission infrastructure capital that is included in this budget in Projects Funded In Advance.

- As part of its continuing efforts, Bonneville is working to further optimize debt service costs (often referred to as debt optimization elsewhere in this budget). BPA, in collaboration with EN, is pursuing the refinancing of certain EN bonds as part of an ongoing debt optimization program. Through this program, BPA uses the reductions in debt service for its EN bonds to make advance payments on its Federal debt. Implementation of the refinancing components will be subject to favorable market conditions and interest rate environment.

Budget Estimates and Planning:

- This FY 2009 budget includes capital and expense estimates for PS based on forecasts in the FY 2007 Final Power Rate proposal, and associated outyear estimates for FYs 2010-2013. TS capital and expense estimates are based on 2008 Transmission Rate Case estimates and associated outyear estimates for FYs 2010-2013. FY 2007 costs are based on BPA's audited actual financial results.

- Capital funding levels also reflect BPA's Capital Planning Review process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region, and national energy security goals. Capital investment levels in this FY 2009 budget also reflect executive management decisions from BPA's Capital Allocation Board.

- The FYs 2007-2013 revenue estimates in this budget, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools; for example, upcoming rate adjustment mechanisms, reduced cost estimates, a net revenue risk adjustment, debt management strategies, and/or short-term financial tools to manage net revenues and cash.

- Revenue calculations include depreciation and 4(h)(10)(C) credit assumptions. These credits offset BPA's fish and wildlife program costs allocable to the non-power project purposes of the FCRPS, consistent with the Northwest Power Act. FYs 2008-2009 credits for 4(h)(10)(C) included in this FY 2009 budget are estimated at $85 million annually. Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that, along with actual market conditions, will impact revenues and expenses.

- Bonneville's efforts to keep its rates as low as possible are augmented by the implementation of the Bonneville Appropriations Refinancing Act (part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996) that refinanced Bonneville's outstanding repayment obligations on appropriations. The legislation called for raising low interest rates on historic appropriations to then current Treasury market rates and resetting the principal of unpaid FCRPS appropriations. As called for in the legislation, Bonneville submitted its calculations and interest rate assignments implementing the refinancing to the Treasury. The Treasury then approved the BPA submission in July 1997, thus finalizing the implementation of the Bonneville Appropriations Refinancing Act refinancings.

- The Northwest Power Act created the REP to extend the benefits of low-cost Federal power to the residential and small farm customers of Pacific Northwest electric utilities that meet certain conditions. The 1996 Comprehensive Regional Review (Comprehensive

Review) recommended that Bonneville engage in settlement discussions regarding the REP. Bonneville then developed a Subscription Strategy based on the recommendations of the Comprehensive Review. That Strategy proposed a comprehensive settlement of REP disputes with IOUs in the Pacific Northwest, which resulted in new contracts with regional IOUs that provided power and monetary benefits to their residential and small farm customers.

The 2000 REP Settlement Agreements and the way the settlement costs were allocated in setting the Priority Firm (PF) rate were challenged by public utilities and others in the Ninth Circuit Court of Appeals. The PF rate is the cost-based rate that preference customers pay for their requirements purchases from BPA. On May 3, 2007, the court held that the REP Settlement Agreements were inconsistent with the Northwest Power Act and that the settlement costs were improperly allocated in setting the PF rate.

As a result of these court rulings, payments to the IOUs were suspended in May 2007. Regional discussions continue that could lead to a recommendation to BPA on how best to implement a Residential Exchange Program, beginning in FY 2009. However, the PF rate remains unchanged in the meantime. BPA is planning a section 7(i) rate proceeding during FY 2008 to revise FY 2009 power rates, as well as a public process to review and revise the 1984 Average System Cost Methodology, to respond to the Court's rulings. These processes are expected to conclude in 2008.

- The Energy Policy Act of 2005 authorized FERC to approve and enforce mandatory Electric Reliability Standards with which users, owners and operators of the bulk power system, including traditionally non-jurisdictional entities, are required to comply. These standards became enforceable on June 18, 2007, and compliance is monitored by the North American Electric Reliability Corporation (NERC) and the regional reliability organizations. Because FERC's authority includes the imposition of financial penalties for violations, BPA may be required to pay fines in the event of BPA violations of FERC-approved reliability standards.

- As part of its strategic staffing efforts and implementation of operational efficiency initiatives, Bonneville has shown a downward trend in Full-Time Employee (FTE) levels since FY 2003. BPA expects its succession planning efforts and continuing efficiency initiatives in targeted areas to level out FTE at about 3,000 in the outyears. BPA continues to pursue various authorities, including the use of voluntary separation incentives (VSI) and voluntary early retirement authority (VERA) to help achieve targeted levels. Annual Bonneville FTE projections included in this FY 2009 budget for FYs 2008 and 2009 are 3,000.

Fish and Wildlife Program Overview:

- Bonneville is committed to continue funding its share of the region's efforts to recover listed Columbia Basin fish and wildlife. To the extent possible, Bonneville is integrating the actions implemented in response to the FCRPS Biological Opinions with projects implemented under the Council's Fish and Wildlife Program. Sub-basin Plans that include prioritized strategies for mitigation actions will help guide project selection to meet both BPA's ESA and Northwest Power Act responsibilities.

- Discussion of a minimum cost-sharing requirement for fish and wildlife projects funded by BPA in 2007 and beyond is continuing in ongoing discussions with the Council and the regional fish and wildlife managers and Northwest Tribes. As part of these discussions for the Integrated Fish and Wildlife Program, BPA has recommended a reorientation and transition of the program over FYs 2007 – 2009 that places greater emphasis on projects that are performance based and deliver more results on-the ground. On-the ground results include habitat protection, enhancement, tributary passage, screening and hatchery efforts.

- Consistent with the PFR, this FY 2009 budget sets an estimated Fish and Wildlife program level of $36 million in capital and $143 million in expense for FYs 2007 – FY 2009. These estimates, as well as those for other Bonneville fish program costs may change, however, depending upon evolving circumstances including the long-term effect of Federal court decisions on the NOAA Fisheries 2004 Biological Opinion and the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion.

- Many of the actions in the FCRPS Biological Opinions and the Council's program overlap, particularly in the areas of habitat and hatchery offsite mitigation measures. The FCRPS Action Agencies' (Corps, Reclamation, and Bonneville) Biological Opinion Implementation Plans describe an approach that maximizes the use of the Council's regional processes to identify and select projects that avoid jeopardizing the survival of the ESA-listed species and to protect, mitigate and enhance fish and wildlife; both listed and non-listed affected by the operation of the FCRPS. The Council's Fish and Wildlife Program provides the mechanism for integrating activities focused on ESA-listed fish stocks in the 2004 BiOp and USFWS 2000 and 2006 Biological Opinions for the FCRPS with those for non-listed species affected by the Columbia Basin's Federal and non-Federal hydrosystems.

- The FY 1997 Energy and Water Development Appropriations Act added section 4(h)(10)(D) to the Northwest Power Act, directing the Council to appoint an Independent Scientific Review Panel (ISRP) "to review a sufficient number of projects" proposed to be funded through Bonneville's fish and wildlife budget "to adequately ensure that the list of prioritized projects recommended is consistent with the Council's program." The Northwest Power Act further states that ". . . in making its recommendations to Bonneville, the Council shall consider the impact of ocean conditions on fish and wildlife populations; and shall determine whether the projects employ cost-effective measures to achieve program objectives." Consequently, projects funded by Bonneville under the program are typically reviewed and prioritized as part of the Council recommendation process.

- Included with the budget schedules section of this budget document is the current tabulation of Bonneville's fish and wildlife costs from FY 1996 through 2007.

President's Management Agenda:

- In the area of the President's Management Agenda (PMA), Bonneville is leveraging the President's initiatives to achieve efficiencies while preserving the long-term value of the FCRPS. Bonneville is self-reporting its Current Status as "green", or successful, on both the Financial Management and the Integrating Budget and Performance initiatives. BPA continues to coordinate closely with DOE to accommodate accelerated budget and financial results reporting requirements.

  Bonneville has received a clean audit opinion since the mid-1980s and no material weaknesses have been identified in controls over financial reporting. In accordance with OMB Circular A-123, BPA conducted its assessment of the effectiveness of its controls over financial reporting and is able to make an unqualified attestation. Bonneville's financial management systems and reporting procedures meet Federal standards, comply with Generally Accepted Accounting Principles (GAAP), and are consistent with the President's Management Agenda.

- In the area of Expanding E-Government, Bonneville is self-reporting its Progress Toward Implementing the President's Management Agenda as "green." Supporting "E-Gov" initiatives, BPA has expanded its participation and efforts in this area and has consolidated its business and administrative Information Technology (IT) groups to gain operating efficiencies and improve overall performance. Bonneville has developed an Enterprise Resource Planning system that integrates its major business processes and provides its managers and employees with access to timely and accurate financial, personnel, and property reports. BPA will continue to work with DOE to expand and strengthen its E-Gov initiative participation.

  Bonneville is self-reporting "green" in Current Status and "green" in Progress toward Implementing the President's Management Agenda in the area of Human Capital. This initiative has served as a catalyst in redefining BPA's organizational strategy, in developing and getting alignment with meaningful objectives, and in assigning clear accountabilities. Development of a new Human Resource Management Information System tool to support organizational development plans focused on closing mission critical skills gaps is underway. Additionally, as a result of efficiency improvement recommendations, developmental cross training programs are being utilized to support succession planning.

Overview of Detailed Justifications:

Bonneville's Detailed Justification Summaries, included in this FY 2009 budget, follow present budget requirements for budget line items on the basis of accrued expenditures.

Accrued expenditure is the basis of presenting Bonneville's program funding levels in the power and transmission rate making processes and the basis upon which Bonneville managers control their resources to provide products and services. Accrued expenditures relate period costs to period performance. Traditional budget obligation requirements for Bonneville's budget are assumed on the Program and Financing Summary Schedule prepared in accord with OMB Circular A-11.

The organization of BPA's FY 2009 budget and these performance summaries reflect Bonneville's business services basis for utility enterprise activities. Bonneville's major areas of activity on a consolidated budget and accounting basis include power and transmission with administrative costs included. PS includes line items for Fish and Wildlife, Conservation and Energy Efficiency, REP, Associated Projects O&M Costs, and the Council. Environmental activities are shown in the relevant power and transmission services, as are reimbursable costs. Bonneville's interest expenses, pension and post-retirement benefits, and capital transfers to the Treasury are shown by program.

The first section of performance summaries, Capital Investments, includes accrued expenditures for investments in electric utility and general plant associated with the FCRPS generation and transmission services, conservation and energy efficiency services, fish and wildlife, and capital equipment. These capital investments will require budget obligations and use of existing borrowing authority of $560 million in FY 2009.

The near-term forecast capital funding levels have undergone an extensive internal review as a result of BPA's Capital Planning Review process and its associated capital asset management strategy. These capital reviews encompass project cost management initiatives, capital investment assessments, and categorization of capital projects to be funded based on risk and other factors. Consistent with BPA's near-term capital funding review process and BPA's standard operating budget process, this FY 2009 budget includes updated capital funding levels for FY 2008. Utilizing this review process helps Bonneville in its efforts to compete in the deregulated wholesale energy market. Bonneville will continue to work with the Corps and Reclamation to optimize the best mix of projects.

In addition to its extensive internal management assessment of capital investments, Bonneville has developed and implemented an associated external capital investment review process that provides significant benefits to Bonneville. The combined internal and external processes add value by both improving direction on what the FCRPS invests in (tying investments more closely to agency strategy) and by improving how those investments are made (better analysis and review of capital investments and their alternatives). BPA will continue its efforts to refine and further implement its capital investment review process to improve the value provided.

Bonneville's second section of the performance summaries, entitled Annual Operating Expenses, includes accrued expenditures for services and program activities financed by power sales revenues, transmission services revenues and projects funded in advance. For FY 2009, budget expense obligations are estimated at $2,865 million. The total program requirements of all Bonneville programs include estimated budget obligations of $3,550 million in FY 2009.

Bonneville Power Administration

Funding Profile by Subprogram 1/

(accrued expenditures in thousands of dollars)

	Fiscal Year				
	2007 (Audited Actuals)	2008 Original /2	2008 Adjustments	2008 Revised /2	2009 Proposed
Capital Investment Obligations					
Associated Project Costs 3/	108,351	N/A	-	158,675	137,330
Fish & Wildlife	35,186	N/A	-	36,000	36,000
Conservation & Energy Efficiency 3/	6,955	N/A	-	42,000	42,000
Subtotal, Power Services 4/	150,492	N/A	-	236,675	215,330
Transmission Services	140,965			242,370	293,533
Capital Equipment & Bond Premium	20,610	N/A	-	31,017	51,123
Total, Capital Obligations 3/ 5/	312,067	538,480	-	510,062	559,986
Expensed and Other Obligations					
Expensed	2,349,791	2,464,963	-	2,718,980	2,865,884
Projects Funded in Advance	107,269	94,989	-	71,775	125,318
Total, Obligations	2,769,127	3,098,432		3,300,817	3,551,188
Capital Transfers (cash) 5/	623,400	877,573	-	408,264	275,723
BPA Total	3,392,527	3,976,005	-	3,709,081	3,826,911
Full-time Equivalents (FTEs)	2,896	3,000	-	3,000	3,000

Public Law Authorizations include:

Bonneville Project Act of 1937, Public Law No. 75-329, H.R. 7642

Federal Columbia River Transmission Act of 1974, Public Law No. 93-454 S. 3362

Regional Preference Act of 1964, Public Law No. 88-552

Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act), Public Law No. 96-501, S. 885

Outyear Funding Profile by Subprogram 1/

(accrued expenditures in thousands of dollars)

	Fiscal Year			
	2010	2011	2012	2013
Associated Project Costs 3/	143,325	148,314	153,236	158,181
Fish & Wildlife	36,000	36,000	36,000	36,000
Conservation & Energy Efficiency 3/	40,000	40,000	45,000	45,000
Subtotal, Power Services 4/	219,325	224,314	234,236	239,181
Transmission Services	278,184	369,836	419,059	319,631
Capital Equipment & Bond Premium	54,798	28,363	28,431	29,501
Total, Capital Obligations 3/ 5/	552,307	622,513	681,726	588,313
Expensed and Other Obligations				
Expensed	2,695,594	2,789,216	2,708,184	2,667,493
Projects Funded in Advance	65,856	78,966	72,242	72,603
Total, Obligations	3,313,757	3,490,695	3,462,152	3,328,409
Capital Transfers (cash) 5/	423,976	417,680	293,841	246,661
BPA Total	3,737,733	3,908,375	3,755,993	3,575,070
Full-time Equivalents (FTEs)	3,000	3,000	3,000	3,000

The accompanying notes are an integral part of this table.

1/ This budget has been prepared in accordance with the Budget Enforcement Act (BEA) of 1990. Under this Act all BPA budget estimates are treated as mandatory and are not subject to the discretionary caps included in the BEA. These estimates support activities which are legally separate from discretionary activities and accounts. Thus, any changes to BPA estimates cannot be used to affect any other budget categories which have their own legal dollar caps. Because BPA operates within existing legislative authority, BPA is not subject to a Budget Enforcement "pay-as-you-go" test regarding its revision of current-law funding estimates.

2/ Original estimates reflect BPA's FY 2008 Congressional Budget Submission. Revised estimates, consistent with BPA's annual near-term funding review process, provide notification to the Administration and Congress of updated capital and expense funding levels for FY 2008.

3/ Includes infrastructure investments designed to address the long-term needs of the Northwest and to reflect significant changes affecting BPA's power and transmission markets.

4/ Power Services includes Fish & Wildlife, Residential Exchange, Planning Council, Conservation & Energy Efficiency and Associated Project Costs which have been shown separately for display purposes.

5/ This FY 2009 budget includes capital and expense estimates for PS based on forecasted FY 2007 Final Power Rate Proposal and associated outyear estimates for FYs 2010-2013. The TS capital and expense estimates are based on forecasted Transmission 2008 Rate Case estimates and associated outyear estimates for FYs 2010-2013.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2009 budget have been updated to reflect executive management decisions from BPA's Capital Allocation Board.

The cumulative amount of actual advance amortization payments as of the end of FY 2007 is $2,091 million.

Refer to 16 USC Chapters 12B, 12G, 12H, and BPA's other organic laws, including P.L. 100-371, Title III, Sec. 300, 102 Stat. 869, July 18, 1988 regarding BPA's ability to obligate funds.

Major Outyear Considerations

Bonneville's outyear estimates reflect its ongoing efforts to achieve its long-term mission and strategic direction. The outyear estimates are developed with consideration of and support of BPA's multi-year performance targets that lay out the course for achieving BPA's long-term objectives. Outyear capital investment levels support BPA's infrastructure program, hydro efficiency program, conservation and energy efficiency projects, and its fish and wildlife mitigation projects.

With passage of the Energy Policy Act of 2005, Bonneville continues to incorporate the various aspects of the legislation related to its business, in particular the energy supply, conservation and new energy technologies for the future that are highlighted in the legislation.

Power Services - Capital

Funding Schedule by Activity

Power Services - Capital (accrued expenditures) (dollars in thousands)	FY 2007	FY 2008	FY 2009
Associated Project Costs	108,351	158,675	137,330
Fish & Wildlife	35,186	36,000	36,000
Conservation & Energy Efficiency	6,955	42,000	42,000
Total, Power Services - Capital	150,492	236,675	215,330

Outyear Funding Schedule

(accrued expenditures) (dollars in thousands)	FY 2010	FY 2011	FY 2012	FY 2013
Total, Power Services - Capital.	219,325	224,314	234,236	239,181

Description

Associated Project Costs provide for direct funding of additions, improvements and replacements of existing Reclamation and Corps hydroelectric projects in the Pacific Northwest that provide for increased performance and availability of generating units. The Reclamation and Corps hydro projects produce electric power which is marketed by Bonneville.

Maintaining the availability and increasing the efficiency of the FCRPS is critical to ensuring that the region has an adequate, reliable and low-cost power system. The FCRPS represents about 80 percent of Bonneville's power supply and is composed of 31 operating Federal hydro electric projects with over 200 generating units. These projects have an average age of over 45 years, with some that exceed 60 years of age. Through direct funding and the close cooperation of the Corps and Reclamation, Bonneville uses its Treasury borrowing authority to make investments needed to restore generation availability and improve efficiency, reducing demand on Corps and Reclamation appropriations for power-related investments. Since the beginning of direct funding, Bonneville along with these joint operating partners have significantly improved system performance. In 1999, at the direction of Congress, Bonneville issued a report that it soon began to implement called the "Asset Management Strategy for the FCRPS." Bonneville concluded in this report that it needed to invest nearly $1 billion in the projects over the next 12-15 years. Without these investments, which are focused on restoring and maintaining the reliability of the system, history indicates that unit availability may initially decline at a rate of about 1.5 percent per year. Supplementary analyses and experience with the system have revealed additional investment needs above and beyond the levels originally planned under the Asset Management Strategy for this and the next several rate periods.

These planned investments, included in this FY 2009 budget funding estimates, will maintain the output of the FCRPS. Moving forward with these cost-effective opportunities to expand the generation and to preserve and enhance the capability of the Federal system is a smart economic and environmental decision when compared to purchasing power from the market to serve growing Pacific Northwest electricity needs.

The Fish and Wildlife program provides for the protection, enhancement and mitigation of Columbia River Basin fish and wildlife due to losses attributed to the development and operation of the Federal hydroelectric projects on the Columbia River and its tributaries from which Bonneville markets power, pursuant to Section 4(h) of the Northwest Power Act. Bonneville satisfies a major portion of its fish and wildlife responsibilities by meeting the Administrator's obligation under the Council's Fish and Wildlife Program.

Bonneville is also mandated to implement measures called for under the ESA. These measures are part of the most recent biological opinions issued in November 2004 by NOAA Fisheries (2004 Biop) and in 2006 by the USFWS (2006 Biop) to address the effects of the operation of the FCRPS on threatened and endangered salmon and steelhead and ESA-listed Kootenai River white sturgeon and bull trout. The biological opinions require the FCRPS Action Agencies to implement actions in the Columbia River Basin that address impacts of the Federal hydrosystem on ESA-listed fish to ensure that operation of the FCRPS does not jeopardize the continued existence of listed species or adversely modify their designated critical habitat. In February 2005, the FCRPS Action Agencies published an implementation plan for their proposed action addressed in the 2004 BiOp. The implementation plan, together with projects undertaken to address mitigation for non-listed species under the Northwest Power Act, and those to address requirements of the USFWS 2000 and 2006 Biological Opinion form the basis for Bonneville's planned capital investment of $36 million for FYs 2008 and 2009.

The 2004 BiOp was challenged in Federal District Court. In October 2005, the District Court invalidated the 2004 BiOp, although leaving it "in place" during the remand period. The Judge also ordered the sovereign parties to collaborate during the remand process, to try to find an acceptable approach for the 2004 BiOp that would have regional support. In December, the Department of Justice filed a notice to appeal the District Court's October 2005 remand order. However, the Federal parties continue to support the court ordered collaboration on the 2004 BiOp, even though an appeal has been filed. In response to litigation seeking injunctive relief on the FCRPS in 2006, the Court approved the Federal spill plan with two modifications. In 2006 (the timeframe of the injunction), the FCRPS continued to spill during late spring and late August. The 2007 spill plan largely repeats the 2006 plan. The collaboration process has continued to make progress over the past two years and is now scheduled to be completed by spring 2008 when BPA anticipates NOAA Fisheries will complete a final FCRPS BiOp.

There has also been litigation directed at the USFWS Biological Opinions for Libby dam. In 2003, the Corps and BPA reinitiated consultation on the operations at Libby dam to address impacts to recently designated critical habitat for the Kootenai River white sturgeon, and to evaluate information that had been developed on the Kootenai River white sturgeon and bull trout since the 2000 USFWS BiOp. That consultation was completed in February 2006, but was challenged by environmental groups, the Kootenai Tribe, and the State of Montana in the Federal District Court of Montana. However these parties have reached tentative agreement on a long term plan of recovery efforts including a combination of hatchery, habitat and flow regimes that can be implemented by BPA, Corps, Kootenai Tribe, State of Montana and others.

Bonneville's fish and wildlife capital program is directed at activities that increase numbers of Columbia River Basin fish and wildlife resources including projects designed to increase juvenile and adult fish passage in tributaries and at mainstream dams, and increase fish production and survival through construction of hatchery and acclimation facilities, land acquisitions for resident fish and wildlife that are consistent with Bonneville's Capital Policy, and fish monitoring facilities. Capital project funding will focus on integrating ESA-related priorities with the Council's Fish and Wildlife Program.

The FY 1997 Energy and Water Appropriations Act added section 4(h)(10)(D) to the Northwest Power Act, directing the Council to appoint an ISRP "to review a sufficient number of projects" proposed to be funded through Bonneville's fish and wildlife budget "to adequately ensure that the list of prioritized projects recommended is consistent with the Council's program." The Northwest Power Act further states that " . . . in making its recommendations to Bonneville, the Planning Council shall consider the impact of ocean conditions on fish and wildlife populations; and shall determine whether the projects employ cost effective measures to achieve program objectives." The Conference Report on the FY 1999 Energy and Water Development Appropriations Act included a new assignment for the ISRP and the Council. The ISRP was to review the fish and wildlife projects, programs, or measures included in Federal agency budgets that are reimbursed and/or directly funded by Bonneville and to make funding recommendations to Congress. The ISRP was directed to determine whether the proposals are consistent with the scientific criteria in the Northwest Power Act as amended in 1996, and to provide a report to the Council by April 1 of each year. The Council, in turn, must report to Congress annually by May 15.

The Federal Caucus, a group of eight agencies operating in the Columbia River Basin that have natural resource responsibilities related to ESA, released in December 2000 a comprehensive long-term strategy to restore ESA-listed fish throughout the Columbia Basin. This strategy includes the "All-H" paper that focuses on the establishment of explicit, scientifically based performance standards to gauge the status of salmon and the success of recovery efforts. Consistent with the principles of the All-H Strategy, Bonneville is implementing much of the off-site mitigation actions required by the FCRPS Biological Opinions through the Council's Fish and Wildlife Program.

Under the 1980 Northwest Power Act, the Fish and Wildlife Program is tasked with protecting, mitigating and enhancing Columbia River Basin fish and wildlife affected by any hydroelectric project in the basin. The Council's Fish and Wildlife Program provides the mechanism for integrating activities focused on ESA-listed fish stocks in the 2004 BiOp and USFWS 2006 Biological Opinions for the FCRPS with those for non-listed species affected by the Columbia Basin's Federal and non-Federal hydrosystems. Recently completed Sub-basin Plans that include strategies for mitigation actions will help guide project selection to meet both BPA's ESA and Power Act responsibilities. Additionally, discussion of a minimum cost-sharing requirement for fish and wildlife projects funded by BPA in 2007 and beyond is continuing in currently ongoing discussions with the Council and the regional fish and wildlife managers and Tribes. BPA established a Cost-Sharing Memorandum of Understanding with the US Forest Service in FY 2007 that requires a programmatic 30 percent cost share for fish and wildlife mitigation projects funded by BPA on US Forest Service lands.

As part of discussions for the Integrated Fish and Wildlife Program, BPA recommended a reorientation and transition of the program over FYs 2007 – 2009 that places greater emphasis on projects that are performance based and deliver more results on-the ground. On-the ground results include habitat protection, enhancement, tributary passage, screening and hatchery efforts. Recommended guidelines are 70 percent of overall program funding for on-the-ground projects; 25 percent to RM&E; and 5 percent for coordination, data management and administration. This FY 2009 budget sets an estimated program level of $36 million in capital and $143 million in expense for FYs 2008 – FY 2009. These estimates as well as those for other Bonneville fish program costs may change, however, depending upon evolving circumstances including the long-term effect of the Federal district court decision on the 2004 BiOp and the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion. Additional proposals to be implemented during FY 2009, if any, resulting from the completion of remand collaboration process (by spring of 2008) requiring expenditures above and beyond the $143 million in expense and $36 million in capital are uncertain at this time.

Conservation is an important part of Bonneville's diverse portfolio of resources that provides a reliable approach to meeting Bonneville's load obligations. When acquiring resources to meet planned future loads, the Northwest Power Act requires the Administrator to first consider and acquire cost-effective conservation that the Administrator determines is consistent with the Northwest Power and Conservation Council's Power Plan. The Council's most recent Power Plan, finalized in January 2005, recommended that the region target 700 aMW of conservation over the next 5-years. Bonneville's share of the conservation target is 40 percent or 280 aMW. Bonneville anticipates that between 100 and 150 aMW of this amount will be acquired under its capital conservation acquisition program. Program performance measurements ($/aMW) indicate that Bonneville is getting excellent value for these investments as benchmarked against other utilities across the nation.

Long-term investments in energy efficiency help buffer the FCRPS against future resource uncertainties. During periods of price volatility, conservation also helps reduce financial risk associated with relying on the market for energy purchases in the future.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Associated Project Costs	**108,351**	**158,675**	**137,330**

BPA will work with both the Corps and Reclamation to reach mutual agreement on those capital improvement projects that need to be budgeted and scheduled, are cost-effective and provide system or site-specific enhancements, increase system reliability, or provide generation efficiencies.

The work is focused on improving the reliability of the FCRPS, increasing its generation efficiency through turbine runner replacements and optimization of hydro facility operation, and small capital reimbursements associated with routine maintenance activities. Also, limited investments may be made in joint use facilities that are beneficial to both the FCRPS operations and to other Corps and Reclamation purposes.

(dollars in thousands)

FY 2007	FY 2008	FY 2009

- **Corps of Engineers (known projects to date)**

FY 2007: Continued main unit and station service breaker replacements at selected projects. Continued hydro optimization investigations and equipment installations at selected projects. Received spare transformers at four projects. Continued emergency notification system replacement/upgrades at several projects. Completed rehabilitation of bridge crane and continue gantry crane replacement at Bonneville. Continued refurbishment/replacement of head gates at Bonneville. Continued exciter installation and DC and preferred AC upgrades at Bonneville Powerhouse 2. Continued rehabilitation work at Bonneville. Continued HVAC upgrade and completed unwatering pumps replacement at Bonneville. Began the planning/design work for station service upgrades, fire protection upgrades and additional crane refurbishments at Bonneville. Completed exciter replacements at John Day and Willamette Valley projects. Repaired failed linkage for unit 16 at John Day. Began planning for fire protection upgrades and bridge crane refurbishment at John Day. Completed installation of replacement transformer for failed unit at The Dalles. Completed work on oil/water separators at The Dalles.

Completed butterfly valve control replacement at Hills Creek. Evaluated turbine runner replacement at Hills Creek. Continued crane refurbishment at Lookout Point. Awarded contract for turbine runner replacement at Lookout Point. Continued governor replacement project, control system installation, hi-lift pump replacement and protective relay replacements at Albeni Falls. Began exciter replacement at Libby. Continued CO2 system replacement at Chief Joseph. Completed evaluating turbine replacements at Chief Joseph and awarded contract for new runners. Continued design for exciter replacements, protective relay replacements and supervisory control console replacement at Chief Joseph.

Continued crane rehabilitation at Chief Joseph. Completed station air compressor replacements at McNary. Discontinued procurement for turbine runner replacements at McNary due to increased price and unavailability of water for the new units – replacement is no longer economical to pursue. Continued with plant modernization at McNary, including fire protection, external oil cooler installation, station service upgrades, transformer installations, and roof replacement. Completed 480 V switchgear replacement at Dworshak. Completed crane rehabilitation at Ice Harbor. Continued installation of replacement generator windings at Lower Granite. Completed or continued replacement and upgrades on protective relays and fire protection at Lower Snake River and Dworshak projects. Began purchase of diesel generator for Lower Granite, Little Goose and Lower Monumental. Continued elevator refurbishment at Little Goose and Lower Monumental. Began intake crane refurbishment at Lower Granite and Lower Monumental, and tailrace crane refurbishment at Lower Monumental.

(dollars in thousands)

FY 2007	FY 2008	FY 2009

Continued with purchase of a spare draft tube bulkhead for Lower Snake projects, plus a variety of smaller continuing or new investments and repairs to failed units. Continued intake crane rehabilitation, heat pump replacement and station service improvements at The Dalles. Continued rehabilitation work at The Dalles. Began fire protection design, spare transformer replacement and disconnect replacement at The Dalles. Completed plant upgrade and repair of the turbine replacement which failed during testing at Cougar. Continued fire protection design for all Willamette Valley projects. Completed crane modernization at Detroit and Big Cliff. Continued generator winding replacement at Detroit. Began electric reliability upgrades at Detroit.

FY 2008: Complete main unit and station service breaker replacements at selected projects. Continue hydro optimization investigations and equipment installations at selected projects. Complete emergency notification system replacement/upgrades at several projects. Complete replacement of gantry crane at Bonneville. Continue refurbishment/replacement of head gates at Bonneville. Continue exciter installation at Bonneville Powerhouse 2. Continue rehabilitation work at Bonneville. Continue HVAC upgrade at Bonneville. Continue station service upgrades, fire protection upgrades and additional crane refurbishments at Bonneville. Continue fire protection upgrades and bridge crane refurbishment at John Day. Continue intake crane rehabilitation, heat pump replacement and station service improvements at The Dalles. Continue rehabilitation work at The Dalles. Continue fire protection design, spare transformer replacement and disconnect replacement at The Dalles. Continue fire protection upgrades at all Willamette Valley projects. Complete generator winding replacement at Detroit in conjunction with powerhouse fire restoration. Continue electric reliability upgrades at Detroit. Continue turbine runner replacement at Hills Creek. Continue crane refurbishment at Lookout Point.

Continue turbine runner replacement at Lookout Point. Complete governor replacement project, control system installation, hi-lift pump replacement and protective relay replacements at Albeni Falls. Complete exciter replacements at Libby. Continue CO2 system replacement at Chief Joseph. Continue turbine runner replacements at Chief Joseph. Continue exciter replacements, protective relay replacements, and automatic generator synchronizer replacements at Chief Joseph. Complete crane rehabilitation and repair of unit 21 at Chief Joseph. Continue with plant modernization at McNary, including fire protection, external oil cooler installation, station service upgrades, transformer installations, and roof replacement. Begin replacements of generator windings at McNary. Continue bridge crane and elevator refurbishment at Dworshak. Continue installation of replacement generator windings at Lower Granite. Complete or continue fire protection upgrades at Lower Snake River and Dworshak projects. Continue diesel generator purchase for Lower Granite, Little Goose and Lower Monumental. Complete elevator refurbishment at Little Goose and Lower Monumental. Continue intake crane refurbishment at Lower Granite and Lower Monumental, and tailrace and bridge crane refurbishments at Lower Monumental. Continue with purchase of a spare draft tube bulkhead for Lower Snake projects, plus a variety of smaller continuing or new investments and repairs to failed units.

(dollars in thousands)		
FY 2007	FY 2008	FY 2009

FY 2009: Continue hydro optimization investigations and equipment installations at selected projects. Continue refurbishment/replacement of head gates at Bonneville. Complete exciter installation at Bonneville Powerhouse 2. Continue rehabilitation work at Bonneville. Continue HVAC upgrade at Bonneville. Continue station service upgrades, fire protection upgrades and additional crane refurbishments at Bonneville. Continue fire protection upgrades and bridge crane refurbishment at John Day. Continue fire protection upgrades, heat pump replacement and station service improvements at The Dalles. Continue rehabilitation work at The Dalles. Complete fire protection upgrades at all Willamette Valley projects. Continue electric reliability upgrades at Detroit. Continue turbine runner replacement at Hills Creek. Complete crane refurbishment at Lookout Point. Continue turbine runner replacement at Lookout Point. Continue CO2 system replacement at Chief Joseph. Continue turbine runner replacements at Chief Joseph. Continue exciter replacements and protective relay replacements at Chief Joseph. Continue with plant modernization at McNary, including fire protection, external oil cooler installation and station service upgrades. Continue installation of replacement generator windings at Lower Granite. Continue diesel generator purchase for Lower Granite, Little Goose and Lower Monumental. Continue intake crane refurbishment at Lower Granite. Complete with purchase of a spare draft tube bulkhead for Lower Snake projects, plus a variety of smaller continuing or new investments and repairs to failed units.

Bureau of Reclamation (known projects to date):

FY 2007: Continued Grand Coulee runner replacements. Continued main unit breaker replacements and air housing coolers at Grand Coulee. Continued relay and switchgear replacements at Grand Coulee. Continued hydro optimization investigations and equipment installations at Grand Coulee. Continued SCADA replacement at Grand Coulee and Hungry Horse. Completed river bank monitoring system and station service transformer replacements at Grand Coulee. Began failed transformer replacement, 500 kV differential relay replacements, right powerhouse station service upgrade, third powerhouse transformer replacements, third powerhouse exciter replacements, an elevator refurbishment and roof replacements at GCL. Continued or began various breaker replacements at Hungry Horse. Completed exciter replacement at Anderson Ranch. Continued transformer replacements at Green Springs and Roza. Completed DC upgrade at Palisades. Began roof replacement at Palisades. Continued seal ring replacement at Chandler. Began design of exciter replacement at Chandler and Roza, plus a variety of smaller continuing or new investments and repairs to failed units

	(dollars in thousands)	
FY 2007	FY 2008	FY 2009

FY 2008: Continue Grand Coulee runner replacements. Continue main unit breaker replacements and air housing coolers at Grand Coulee. Complete switchgear replacements at Grand Coulee. Continue hydro optimization investigations and equipment installations at Grand Coulee. Continue SCADA replacement at Grand Coulee and Hungry Horse. Complete the elevator refurbishment and roof replacements at GCL. Complete 500 kV differential relay replacements. Continue failed transformer replacement, right powerhouse station service upgrade, third powerhouse transformer replacements and third powerhouse exciter replacements at Grand Coulee. Continue various breaker replacements at Hungry Horse. Complete transformer replacements at Roza. Continue transformer replacement at Green Springs. Complete roof replacement at Palisades. Complete seal ring replacement at Chandler. Complete exciter replacement at Chandler and Roza, plus a variety of smaller continuing or new investments and repairs to failed units.

FY 2009: Continue Grand Coulee runner replacements. Complete main unit breaker replacements and air housing coolers at Grand Coulee. Continue hydro optimization investigations and equipment installations at Grand Coulee. Continue SCADA replacement at Grand Coulee and Hungry Horse. Continue right powerhouse station service upgrade, third powerhouse transformer replacements and third powerhouse exciter replacements at Grand Coulee. Continue or complete various breaker replacements at Hungry Horse. Complete transformer replacements at Green Springs. Complete seal ring replacement at Chandler. Complete exciter replacement at Chandler, plus a variety of smaller continuing or new investments and repairs to failed units.

Fish and Wildlife	**35,186**	**36,000**	**36,000**

Specific project solicitation and funding decisions were completed in early 2007. The following projects may be candidates for capital funding in FY 2009. It is Bonneville's intention to proceed with design, environmental review, and construction of those projects from this list and that are recommended for funding within the available budget. The costs indicated are preliminary estimates only and actual costs may be greater or lower than those estimates, depending on final environmental review decisions and design and construction costs.

(dollars in thousands)

FY 2007	FY 2008	FY 2009

FY 2007-2009 efforts include continued implementation of high priority ESA-related projects and activities associated with the 2004 BiOp and USFWS 2000 and 2006 Biological Opinions and amended FCRPS Action Agency proposal, consistent with the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion. Implementation of reforms to hatchery programs that help reduce impacts upon ESA-listed populations may also be warranted as information on the types of changes to these facilities are established and priorities for sequencing implementation are developed. Projects that implement the NOAA Fisheries 2004 and USFWS 2006 Biological Opinions are also described in the updated FCRPS Action Agencies' Implementation Plans. Although not subject to the Northwest Power Act's section 4(h)(10)(B) for capital construction projects, Bonneville may include capitalization of investment in some wildlife habitat acquisitions and in land acquisition for fish and wildlife provided such land acquisition costs exceed $1 million, such investment provides a creditable and quantifiable benefit against a defined obligation for Bonneville, and is consistent with Bonneville's Capital Policy.

The five types of capital projects as defined by the FY 2007 Power Rate Case are as follows:

1) ***Tributary passage*** -- Activities that enhance fish passage to tributary rivers. For the purpose of this policy, a tributary is defined by the Council designated sub-basin of the tributary. Functionally interdependent work elements could contain the following: wells, ladders, screens, pumping, culverts, diversion (irrigation) consolidation, piping to reduce water loss, irrigation efficiencies (drip irrigation), lining of ditches (seepage reduction), removal of damming objects or pushup dams in conjunction with related construction, and construction related habitat restoration.
2) ***Gas abatement*** -- Projects that reduce or eliminate the super-saturation of gaseous nitrogen in water beneath the dam spillways.
3) ***Hatchery facility construction*** -- Projects and activities relating to the construction of fish hatcheries, including related satellite facilities (acclimation ponds). This may also include construction-related habitat restoration.
4) ***Mainstem passage*** -- Projects and activities which benefit fish passage in the mainstem of Columbia River or Snake River. Capital projects include: ladders, removable spillway weirs, collection facilities, PIT tag facilities, etc.
5) ***Land acquisition*** -- Land acquisition projects protect, enhance, and maintain instream wetland and riparian habitat and provide habitat units (HUs) for wildlife and instream miles for resident fish to fulfill the legal obligation of FCRPS.

(dollars in thousands)

FY 2007	FY 2008	FY 2009

Anadromous fish supplementation, production and related facilities, and/or juvenile and adult passage improvement projects that may require capital funds in FY 2009 include the following:

- Yakima River Spring Chinook Supplementation Facility, located in Cle Elum, Washington: This project includes the construction of an interpretive building for public education at Bonneville's existing hatchery and for the design and construction of a monitoring and evaluation building at Nelson Springs for use by project biologists.

-Snake River Spring Chinook Salmon artificial propagation facilities (known as the Northeast Oregon Hatchery or NEOH); to be located on the Upper Grande Ronde River near La Grande, Oregon, on Catherine Creek near Union, Oregon, and on Lostine River near Enterprise, Oregon: The design and construction is expected to continue. This project, as a measure in the Council's Fish & Wildlife Program, would also identify and develop artificial propagation facilities to protect and enhance salmon and steelhead native to the Imnaha and Grande Ronde River Basins.

-Kootenai River Hatchery: The Kootenai River sturgeon hatchery, in Bonners Ferry, Idaho, is in need of hatchery upgrades and expansion to improve temperature control and rearing conditions that will result in the increased overall survival of these ESA-listed fish after release from this facility. In addition this may also include development of a burbot production facility to offset the loss of natural production below Libby Dam. The project requires development and review of a Master Plan prior to implementation. Fish and wildlife resources in the Kootenai drainage were historically abundant and were used by the Kootenai Tribe for cultural and subsistence purposes. Over the past decades, native fish and wildlife populations have declined significantly due to large-scale habitat and ecosystem changes. Native kokanee from the South Arm of Kootenay Lake are considered "functionally extinct," burbot from the lower Kootenai River are on the verge of extinction, and the white sturgeon population in the Kootenai River was listed as endangered by the U.S. Fish and Wildlife Service in 1994. The Kootenai River White Sturgeon Study and Conservation Aquaculture Project was initiated by the Kootenai Tribe of Idaho as a stopgap measure in 1989 to produce fish from wild Kootenai River adults until effective habitat restoration measures could be identified and implemented. Only the long life span of the sturgeon has forestalled extinction to date. Natural recruitment has been absent or limited for decades and the current population of large old fish is steadily dwindling. Continued failure of natural recruitment means that the next generation of Kootenai white sturgeon will come almost entirely from the hatchery.

(dollars in thousands)

FY 2007	FY 2008	FY 2009

-Nez Perce Tribal Hatchery: Additional rearing and acclimation facilities are requested as part of the existing Nez Perce Tribal Hatchery in Clearwater County, Idaho, for reintroduction of up to 700,000 coho smolts into the Clearwater River in Idaho. Requires development and review of Master Plan prior to implementation. The Nez Perce Tribe (NPT) is motivated to implement the Clearwater Coho Restoration Project (CCRP) for the following reasons: 1) historically, coho salmon were one of the species making up a complex multi-species anadromous ecosystem within the Clearwater; 2) the 1855 Treaty with the United States reserved harvest rights at all usual and accustomed places; 3) coho salmon are a cultural resource to the NPT; and 4) the extirpation of coho salmon from the Snake River Basin remains unmitigated. The NPT goal is to restore coho salmon to the Clearwater subbasin measured by 14,000 adults at Lower Granite Dam annually. The 2007-2009 proposal is for completing the Step planning process and construction based on the 2004 Master Plan. Plans are to develop an integrated management plan to optimize the use of hatchery fish to meet recovery and harvest objectives.

-Redfish Lake Sockeye Captive Brood expansion: Project would expand the sockeye captive broodstock program by constructing new or additional facilities at Eagle Hatchery in Eagle, Idaho, Oxbow Hatchery in Multnomah County, Oregon, and at an additional site to be selected in Idaho to increase production annually to between 150,000 and 1,000,000 smolts, depending upon the outcome of the BiOp Remand Collaborative Process. Project requires development and review of a Master Plan prior to implementation. Precipitous declines of Snake River sockeye salmon led to their Federal listing as endangered in 1991 (56 FR 58619). In that same year, the Idaho Department of Fish and Game (IDFG) initiated a Captive Broodstock Program to maintain Snake River sockeye salmon and prevent species extinction. The ultimate program goal is to reestablish sockeye salmon runs to Stanley Basin waters and to provide for sport and treaty harvest opportunities. The program’s near-term goal is to prevent species extinction, slow the loss of critical population genetic diversity and heterozygosity, and increase the number of individuals in the population.

-Chief Joseph Dam Hatchery: BPA is proposing to fund the Chief Joseph Dam Hatchery Program, a comprehensive management program for supplementing Chinook salmon below Chief Joseph Dam, in Washington in the Okanogan subbasin and the Columbia River between the confluence of the Okanogan River and Chief Joseph Dam. Project includes a new hatchery facility (at the base of the Chief Joseph Dam) and acclimation ponds (throughout the Okanogan River subbasin), broodstock collection, egg incubation, rearing, release, and selective broodstock collection method development. The objective is to improve production of spring/summer and fall Chinook salmon in the Okanogan River Subbasin below Chief Joseph Dam. Planned production levels are 2 million summer/fall chinook and 0.9 million spring chinook smolts. Exploration of potential cost sharing for O&M and capital is underway with three public utility districts having some level of mitigation responsibility for their hydro projects within this geographic area.

(dollars in thousands)

FY 2007	FY 2008	FY 2009

-Hood River Production Facility: This project includes expansion of existing Parkdale fish facility to accommodate spring chinook rearing, construction of new Hood River adult salmonid trapping facilities, and development of alternative adult trapping sites. Powerdale Dam, which is owned and operated by PacifiCorp, is scheduled for decommissioning during the summer of 2010. The dam forms an integral part of the Powerdale Dam Fish Trap (PDFT), as fish are shunted into the fish trap as they ascend the fish ladder at the facility. Removal of the dam will also remove the fish trapping facility. The PDFT currently provides the foundation for many of the activities associated with implementation of the Hood River Production Program (HRPP). These include: monitoring escapement, collecting life history characteristics, and broodstock acquisition. In order to continue implementing the HRPP, alternative trapping sites will need to be developed. The HRPP has four primary goals: 1) re-establish naturally sustaining runs of spring chinook in the Hood River; 2) re-build naturally sustaining runs of summer and winter steelhead in the Hood River; 3) maintain genetic characteristics of Hood River fish populations; and 4) provide fish for sustainable harvest by both sport and tribal fishers.

-Mid Columbia Coho restoration: Indigenous natural coho salmon no longer occupy the mid-Columbia river basins. Columbia coho salmon populations were decimated in the early 1900s. For several reasons, including the construction and operation of mainstem Columbia River hydropower projects, habitat degradation, release locations, harvest management, and hatchery practices and genetic guidelines, self-sustaining coho populations were not re-established in mid-Columbia basins. Currently, the lack of locally adapted stock and in-basin habitat degradation may be the biggest challenges to coho reintroduction in mid-Columbia tributaries. This program's vision is to re-establish naturally reproducing coho salmon populations in the Wenatchee and Methow subbasins at biologically sustainable levels which provide significant harvest in most years.

Cultural, socio-economic, and ecological benefits are expected from the return of this species to areas where it once occurred in abundance. The phased approach incorporates development of a mid-Columbia hatchery broodstock, local adaptation to tributaries in the Wenatchee and Methow basins, and habitat restoration that will benefit coho as well as ESA-listed spring chinook, steelhead, and bull trout.

-Yakama Coho restoration: Before the ocean and lower Columbia exploitation of salmon and steelhead in the late l9th century and early 20th century, and before the Yakima River valley was developed, the Yakima Subbasin supported large runs of spring, summer and fall Chinook, summer steelhead, coho and sockeye. Historical returns of coho to the Yakima River Basin have been estimated in the range of 44,000 to more than 100,000 fish annually.

Cumulative effects from the disruption of the Yakima Subbasin ecosystem functions and processes, out of subbasin impacts, and harvest of salmon have resulted in a significant decline of fish and wildlife abundance from historic levels. Over the last ten years, Yakima River mouth returns of coho have ranged from about 800 to 6,200 salmon. The significant decrease in abundance of these fish is mirrored on the terrestrial landscape. The goal of this restoration project is to restore extirpated coho salmon to the Yakima River basin at biologically sustainable levels.

-Walla Walla River Juvenile and Adult Passage Improvements: This project would provide safe passage for migrating juvenile and adult salmonids in the Walla Walla Basin by constructing and maintaining passage facilities at irrigation diversion dams and canals.
-Walla Walla Hatchery planning and design. Project requires development and review of a Master Plan prior to implementation.

-Okanogan Basin Locally-Adapted Steelhead Supplementation Program: This project will expand Cassimer Bar Hatchery to meet the estimated production level of 200,000 summer steelhead smolts to supplement natural production within the Okanogan River Basin. The goal is to increase abundance and accelerate recovery of endangered steelhead in the Basin. The Colville Tribes will operate the hatchery program using locally-adapted broodstock collected at weirs in the Basin. Project will require development and review of a Master Plan and completion of the other steps of the Council's 3-Step Review Process.

The FCRPS BiOp Remand Collaboration Process is currently assessing potential hatchery reform actions for all Federally funded hatcheries including those funded by BPA as part of the Council Integrated Fish and Wildlife Program and those programs funded directly by BPA through the Corps, USFWS and Bureau. Specific actions designed to benefit ESA-listed stocks to be funded have not yet been identified and depend upon the outcome of this regional collaborative process, anticipated to conclude in spring 2008. Any new efforts will be identified at that time in the Action Agencies Updated Proposed Action and in updates to yearly implementation plans.

Potential non-construction Wildlife Habitat Acquisitions (Including Conservation Easements):
- Grand Coulee and Chief Joseph Wildlife Habitat Acquisition
- Couer d'Alene Fish and Wildlife Habitat Acquisition
- Albeni Falls Wildlife Mitigation.
- Blue Creek Winter Range Wildlife Habitat Acquisition
- Yakima Valley Fish and Wildlife Habitat Acquisition
- Grande Ronde Wildlife Habitat Acquisition
- Salmon River Fish Habitat Acquisition
- Fish and Wildlife Land Acquisition - Selah Gap to Union Gap
- Palisades and Minidoka Wildlife Habitat Acquisition
- Black Canyon, Boise Diversion, Anderson Ranch Wildlife Habitat Acquisition
- Willamette Fish and Wildlife Habitat Acquisition
- Libby and Hungry Horse Reservoirs Resident Fish Acquisitions

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Conservation and Energy Efficiency	**6,955**	**42,000**	**42,000**

The conservation acquisition program offers several ways for customers to participate in regional conservation. Program components include: (1) utility standard offer and custom programs, which result in customer proposals to conserve energy through residential weatherization, commercial lighting and HVAC (Heating, Ventilation, and Air Conditioning), industrial processes and lighting, and irrigated agriculture; (2) third party delivery programs, such as residential compact fluorescent lighting, "Vending Mi$er" (a program to reduce energy use in regional refrigerated vending machines) and the Water and Waste Water Treatment Facilities program; (3) Federal programs to help Federal installations in the region reduce energy use, which includes the Federal Hatcheries program and work at various dams to help the Corps and Reclamation in their efforts to reduce energy use; and (4) other initiatives still in the design stage.

	FY 2007	FY 2008	FY 2009
Total Power Services – Capital	**150,492**	**236,675**	**215,330**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Associated Project Costs	
▪ Reflects a reshaping of funding requirements based on the need to maintain a minimum level of generation each year.	-21,345
Fish and Wildlife	
▪ Program costs average $36 million annually for FYs 2007 through the rate period.	0
Conservation and Energy Efficiency	
▪ Funding is consistent with the Council's most recent Power Plan, finalized in 2005.	0
Total Funding Change, Power Services - Capital	**-21,345**

Transmission Services – Capital

Funding Schedule by Activity

Transmission Services - Capital	FY 2007	FY 2008	FY 2009
	(accrued expenditures) (dollars in thousands)		
Main Grid	5,261	32,333	70,474
Area & Customer Services	2,635	38,684	31,766
Upgrades & Additions	50,854	70,729	65,108
System Replacements	82,215	100,624	126,185
Projects Funded in Advance	107,269	71,775	125,318
Total, Transmission Services - Capital	248,234	314,145	418,851

Outyear Funding Schedule

	FY 2010	FY 2011	FY 2012	FY 2013
	(accrued expenditures) (dollars in thousands)			
Total, Transmission Services - Capital	344,040	448,802	491,301	392,234

Description

TS is responsible for about 75 percent of the Pacific Northwest's high-voltage transmission. TS provides for all additions, upgrades, and replacements to the Federal BPA transmission system, resulting in reliable service to northwest industrial users and utility customers. The Federal BPA transmission system also facilitates the sale and exchange of power to and from the region.

The eastern blackout on August 14, 2003, alerted the Nation to the lack of investment in utility transmission infrastructure. BPA has been working on infrastructure investments and operational practices to improve the transmission grid since the West Coast disturbance on August 10, 1996. TS has made, and continues to make significant infrastructure improvements and additions to the system to assure reliable transmission in the Northwest. These improvements and additions will help the Federal transmission system continue to comply with national reliability standards, replace aging equipment, allow for interconnection of needed new generation, and remove constraints that limit economic trade or the ability to maintain the system. Prior to beginning the infrastructure improvements, TS had built no major transmission projects since 1987. Only incremental additions had been added to the system over the years.

The Northwest transmission system continues to show signs of stress, as two close calls in 2003 demonstrated. On June 4, 2003, voltage instability in the Spokane area was prevented by quick operator action on the Federal system. Two weeks later, the non-Federal transmission path between Montana and Idaho was overloaded for two days, and operator adjustments prevented load loss. In 2004, it was noted that a small load change at BPA's interconnection with Idaho Power near LaGrande, Oregon, was causing an unusually large voltage change. These examples demonstrate how the transmission system is being ‘pushed’ to its limits of capacity to carry power. The completions of the Grand Coulee-Bell, Kangley-Echo Lake, and Schultz-Wautoma lines projects have provided dispatchers with a greater Operator’s Transfer Capability, and have reduced the likelihood of outages or reduction of transmission capacity for outage situations.

Bonneville’s completed infrastructure investments that further strengthen the network consist of the following projects: Puget Sound Area Additions, North of Hanford/ North of John Day, Cross Cascades North, Celilo Modernization, Eastern Washington Reinforcement, Portland Area Additions.

These projects relieve congestion and contribute toward restoring an adequate reliability margin back into the grid. These additional margins will be used to respond to a competitive market, meet regional load during outages, move power to meet changing loads, perform maintenance without harming the market, and allow Columbia Grid (formerly referred to as Grid West) to start with the regional grid less congested.

In 2005, with the Congressional approval of wind tax credits, a number of potential wind generation companies have made requests for connection to the BPA transmission grid. In 2007 BPA connected 200 MWs and it is expected that in 2008 1100 MWs will be connected and 1300 MWs by FY 2009. The wind generation being proposed is in addition to the 1200 MW of gas and geothermal generation already being proposed in 2008 and 2009.

Bonneville assumes that some generators will seek to interconnect their power projects into the Federal transmission system. Depending on which generators build on sites in the Northwest, and depending on the project locations, between 1000 and 1,600 MW can be interconnected and integrated with the completion of the above additions and improvements. Integration directly into the Federal transmission system will be consistent with BPA’s open access transmission tariff.

As a means to sustain BPA’s limited Treasury financing, third-party funding partnerships are currently being explored as a financing option for some investments.

System Replacements replace high-risk, obsolete, and maintenance-intensive facilities and equipment and reduce the chance of equipment failure by: 1) replacing high voltage transformers and power circuit breakers which are at or near the end of their useful life; 2) replacing risky, outdated and obsolete Control Center and control and communications equipment and systems; and includes replacements provided for in the Commercial Spectrum Enhancement Act (CSE Act) (PFIA work); and 3) replacing all other existing high-risk equipment and facilities affecting the safety and reliability of the transmission system.

Bonneville will continue to fund fiber optic communications facilities needed to meet Bonneville’s projected operational needs. To the extent that these investments create temporary periods of excess fiber optic capacity, such dark fiber capacity can be made available to telecommunications providers and to non-profits to meet public benefit Internet access needs for rural areas and other needs in Bonneville’s service area. Bonneville’s investments in fiber optics, including the role of the private sector in building fiber optic networks, is consistent with the “Fiber Optic Cable Plan” submitted to Congress on May 24, 2000, accompanying the FY 2000 Energy and Water Development Appropriations Act. In accordance with this plan, when possible, Bonneville will establish partnerships with fiber optic facility and service providers to meet its needs.

In December 2004, the Congress passed and the President signed the Commercial Spectrum Enhancement Act (CSEA, Title II of P.L. 108-494), creating the Spectrum Relocation Fund (SRF) to streamline the relocation of Federal systems from certain spectrum bands to accommodate commercial use by facilitating reimbursement to affected agencies of relocation costs. The Federal Communications Commission has auctioned licenses for reallocated Federal spectrum, which will facilitate the provision of Advanced Wireless Services to consumers. Funds were made available to agencies in FY 2007 for relocation of communications systems operating on the affected spectrum. These funds are mandatory and will remain available until expended, and agencies will return to the SRF any amounts received in excess of actual relocation costs. The estimated BPA cost of this relocation is $48.7 million.

As part of the Homeland Security Presidential Directives, Bonneville has completed a physical security assessment of all critical facilities and is implementing security enhancements at these facilities. These security enhancements increase access control to BPA's facilities and provide video surveillance and monitoring capabilities.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Main Grid	**5,261**	**32,333**	**70,474**

Bonneville's strategic objectives for Main Grid projects are to provide voltage support; provide a reliable transmission system for open access, per FERC criteria; provide for relief of transmission system congestion; and assure compliance with the National Electrical Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and BPA reliability standards. During this budgeting period, projects are planned that will provide voltage support to major load areas that are primarily west of the Cascade Mountains, and provide for transmission access for new generation projects to the load center. Reinforcements along the I-5 corridor are also planned.

- FY 2007: (1) Began the planning and design of I-5 Corridor reinforcements; (2)Began the design, material ordering and construction of the Libby-Troy 115kv transmission line upgrade; (3) Completed the environmental work and began the design for the Olympia Peninsula Reinforcement project(formerly known as the Olympic Peninsula Addition project); (4) Began the Preliminary Engineering and Environmental Impact Statement (EIS) for West of McNary Generation Integration Project; (5) Continued planning studies to identify and clarify needed infrastructure additions; (6) Continued planning studies to identify projects driven by NERC/ WECC reliability Standards; (7) Continued planning and design studies to comply with the N-2 outage criteria; (8) Continued planning studies to identify additional system reactive needs to mitigate unacceptable low or high voltage problems and other system additions; (9) Continued planning studies to relieve the transmission system capacity congestion and to integrate new generation facilities.

- FY 2008: (1) Continue design and begin the material ordering of I-5 Corridor reinforcements; (2) Continue the design, material ordering and construction of the Libby-Troy 115KV transmission line upgrade; (3) Continue the construction for the Olympic Peninsula Reinforcement project (formerly know as the Olympic Peninsula Addition project); (4) Continue the preliminary engineering

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

and complete the EIS for the West of McNary Generation Integration Project; (5) Complete the design and begin ordering materials and start construction for the Tri – Cities Reinforcement project; (6) Begin the design and material ordering for the Redmond 230/115 kv bank #2; (7) Continue planning studies to identify and clarify needed infrastructure additions; (8) Continue planning studies and design to identify projects driven by NERC/ WECC reliability Standards; (9) Continue planning and design studies to comply with the N-2 outage criteria; (10) Continue planning studies to identify other system reactive needs to mitigate unacceptable low or high voltage problems and other system additions; (11) Continue planning studies to relieve the transmission system capacity congestion and for integrating potential new generation facilities.

- FY 2009: (1) Continue design and material ordering and begin the construction of I-5 Corridor reinforcements; (2) Complete construction of the Libby-Troy 115KV transmission line upgrade; (3) Complete the construction for the Olympic Peninsula Reinforcement project (formerly known as the Olympic Peninsula Addition project); (4) Begin design and material ordering for the West of McNary Generation Integration Project; (5) Begin the design and material ordering for the Redmond 230/115 kv Bank #2; (6) Begin the design for the Mid – Columbia Area Reinforcement project; (7) Continue planning studies to identify and clarify needed infrastructure additions; (8) Continue planning studies and design to identify projects driven by NERC/ WECC reliability Standards; (9) Continue planning and design studies to comply with the N-2 outage criteria; (10) Continue planning studies to identify other system reactive needs to mitigate unacceptable low or high voltage problems and other system additions; (11) Continue planning studies to relieve the transmission system capacity congestion and for integrating potential new generation facilities.

Area and Customer Services	**2,635**	**38,684**	**31,766**

Bonneville's strategic objective for Area and Customer Service projects is to assure that Bonneville meets the reliability standards and the contractual obligations we have to our customers for serving load.

- FY 2007: (1) Began design of the SVC at Rogue Substation to serve Southern Oregon Coast; (2) Cancelled the design for shunt capacitor addition at Fords Prairie area; (3) Continued design and material ordering and begin construction of the new Hooper Springs (formerly know as Lower Valley Reinforcement ,Caribou Substation); (4) Began the design, material ordering and construction of the City of Centralia Reinforcement Project; (5) Continued preliminary engineering and design for miscellaneous facilities required to meet contractual obligations and maintain reliable service for BPA's service area.

- FY 2008: (1) Complete design and begin material ordering for the SVC at Rogue Substation; (2) Cancelled the addition of the SVC at Port Angeles Substation; (2) Continue construction on Hooper Springs; (3) Complete the City of Centralia Reinforcement Project; (4) Begin the design and material ordering of the Drummond Shunt Capacitors; (5) Begin design and material ordering of the Albany- Eugene Rebuild; (6) Begin the design and material ordering for the Lebanon 115 kv shunt capacitors; (7) Continue preliminary engineering and design for miscellaneous facilities required to meet contractual obligations and maintain reliable service for BPA's service area.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

- FY2009: (1) Complete construction on Hooper Springs; (2) Complete design and construction of the Drummond Shunt Capacitors; (3) Complete the construction of the Albany- Eugene Rebuild; (4) Complete the construction of the Lebanon 115 kv shunt capacitors; (5) Continue preliminary engineering and design for miscellaneous facilities required to meet contractual obligations and maintain reliable service for BPA's service area.

Upgrades & Additions	**50,854**	**70,729**	**65,108**

Bonneville's strategic objectives for Upgrades and Additions are to replace older communications and controls with newer technology including fiber optics in order to maintain or enhance the capabilities of the transmission system; to implement special remedial action control schemes to accommodate new generation and mitigate immediate operational and market constrained paths; and, to support communications and remedial action schemes, among other proposals.

During this budget period, BPA will complete design, material acquisition, construction and activation of several fiber optics facilities to provide bandwidth capacity and high-speed data transfers to eventually replace microwave analog radios, which are technologically obsolete and nearing the end of their useful life. Temporarily, in some areas, excess fiber capacity is being offered for a term to telecommunications providers or to public entities such as public utilities, schools, libraries, and hospitals, providing them access to high-speed telecommunication services as a public benefit.

- FY 2007: Continued developing project scope and agreement for the Maple Valley – SnoKing - Snohomish fiber optic project; (2) Completed design for the 2 mile taps for Sifton and Kennewick Fiber optic projects; (3) Designed 1 mile tap for Augspunger fiber project; (4) Designed 2 miles of fiber between Bonneville power house and Bonneville control house; (5) Continued construction of secondary fiber related projects and digital radio system upgrades to improve the operational telecommunication system; (6) Continued replacement and upgrade of operational and marketing business tools at the Dittmer and Munro control centers; (7) Completed design and construction of seismic upgrade projects; (8) Continued planning, design, material acquisition and construction of special remedial action control schemes required for interconnecting new generation projects and mitigating immediate constrained paths; (9) Continued planning, design, material acquisition and construction of various system additions and upgrades necessary to maintain a reliable system for BPA's service area.

- FY 2008: (1) Begin the design and material acquisition for Maple Valley – SnoKing - Snohomish fiber project; (2) Order materials and construct 2 mile taps for Sifton and Kennewick fiber projects; (3) Order materials and construct 1 mile tap for Augspunger fiber project; (4) Order materials and construct 2 miles of fiber between Bonneville power house and Bonneville control house; (5) Continue planning, design, material acquisition and construction of special remedial action control schemes required for interconnecting new generation projects and mitigating immediate constrained paths; (6) Continue planning, design, material acquisition and construction of various system additions and upgrades necessary to maintain a reliable system for BPA's service area.

- FY 2009: (1) Continue negotiations for joint use fiber project from SnoKing to Intalco; (2) Continue

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

planning, design, material acquisition and construction of special remedial action control schemes required for interconnecting new generation projects and mitigating immediate constrained paths; (3) Continue planning, design, material acquisition and construction of various system additions and upgrades necessary to maintain a reliable system for BPA's service area.

System Replacements	**82,215**	**100,624**	**126,185**

Bonneville's strategic objectives for System Replacement are to replace high-risk, obsolete, and maintenance-intensive facilities and equipment and to reduce the chance of equipment failure by (1) replacing high voltage transformers and power circuit breakers which are at or near the end of their useful life; (2) replacing risky, outdated and obsolete control and communications equipment and systems, and includes mandated replacements due to legislation; and (3) replacing all other existing high-risk equipment and facilities affecting the safety and reliability of the transmission system.

Non-Electric Replacements:

- FY 2007: (1) Completed other non-electric replacements as necessary; (2) Continued the design, material acquisition, and construction for the Access Road Program; (3) Completed 12 security enhancement projects at various substations; (4) Completed order for replacement of three BPA helicopters for future delivery utilizing General Services Administration exchange sale authority; (5) Completed order for two fixed wing and receive delivery of one aircraft utilizing General Services Administration exchange sale authority.

- FY 2008: (1) Complete seismic upgrades to substations and buildings; (2) Complete other non-electric replacements as necessary; (3) Continue the design, material acquisition, and construction for the Access Road Program; (4) Complete 12 security enhancement projects at various substations; (5) Receive delivery of two helicopters; (6) Receive delivery of one fixed wing aircraft utilizing General Services Administration exchange sale authority.

- FY 2009: (1) Complete other non-electric replacements as necessary; (2) Continue the design, material acquisition, and construction for the Access Road Program; (3) Complete 12 security enhancement projects at various substations; (4) Receive delivery of one helicopter.

Electric Replacements:

- FY 2007: (1) Continued replacement of system protection and control equipment and other substation and line facilities as needed to maintain reliability using Reliability Centered Maintenance (RCM) criteria. Such replacements include relays, annunciators, oscillographs, metering and replacing and migrating analog to digital technology and Supervisory Control and Data Acquisition (SCADA) equipment; (2) Continued replacement of under-rated and high maintenance substation equipment; (3) Continued replacing spacer dampers on various 500kV lines; (4) Continued replacing critical, operational tools and marketing business systems at the Dittmer and Munro Control Centers; (5) Continued replacing deteriorating wood pole transmission line structures and insulators with Non-Ceramic Insulators (NCI).

	(dollars in thousands)	
FY 2007	FY 2008	FY 2009

- FY 2008: (1) Continue replacement of system protection and control equipment and other substation and line facilities as needed to maintain reliability using RCM criteria. Such replacements include relays, annunciators, oscillographs, metering and various types of communication related equipment replacing and migrating analog to digital technology and SCADA equipment; (2) Continue replacement of under-rated and high maintenance substation equipment; (3) Continue replacing spacer dampers on various 500kV lines; (4) Continue replacing critical, operational tools and marketing business systems at the Dittmer and Munro Control Centers; (5) Continue replacing deteriorating wood pole transmission line structures, spacer dampers and insulators with NCI.

- FY 2009: (1) Continue replacement of system protection and control equipment and other substation and line facilities as needed to maintain reliability using RCM criteria. Such replacements include relays, annunciators, oscillographs, metering and various types of communication related equipment replacing and migrating analog to digital technology and SCADA equipment; (2) Continue replacement of under-rated and high maintenance substation equipment; (3) Continue replacing spacer dampers on various 500kV lines; (4) Continue replacing critical, operational tools and marketing business systems at the Dittmer and Munro Control Centers; (5) Continue replacing deteriorating wood pole transmission line structures, spacer dampers and insulators with NCI.

Projects Funded in Advance	**107,269**	**71,775**	**125,318**

This category includes those facilities and/or equipment where BPA retains control or ownership but which are funded by a third party or with revenues, either in total or in part. This category also includes investments associated with the CSE Act.

- FY 2007: (1) Continued to integrate various new wind generation projects into BPA transmission grid per Transmission Service Request via the Open Access Tariff; (2) Completed planning studies to identify system impacts and needs regarding proposed new generation projects; (3) Completed environmental cleanup and other work necessary for the sale of BPA facilities; (4) Completed other projects as agreed to with customers; (5) Began preliminary engineering for the radio replacements associated with the CSE Act; (6) Began the design of the California-Oregon Intertie (COI) reinforcement project.

- FY 2008 (1) Continue to integrate various new wind generation projects into BPA transmission grid per Transmission Service Request via the Open Access Tariff; (2) Continue planning studies to identify system impacts and needs regarding proposed new generation projects; (3) Continue environmental cleanup and other work necessary for the sale of BPA facilities; (4) Complete other projects as agreed to with customers; (5) Begin the design and construction for various radio replacements at accessible sites associated with the CSE Act; (6) Continue the design, order materials and start construction of the COI reinforcement project.

- FY 2009: (1) Continue to integrate various new wind generation projects into BPA transmission grid per Transmission Service Request via the Open Access Tariff; (2) Continue planning studies to

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

identify system impacts and needs regarding proposed new generation projects; (3) Continue environmental cleanup and other work necessary for the sale of BPA facilities; (4) Complete other projects as agreed to with customers; (5) Continue the design and construction for various radio replacements at accessible sites associated with the CSE Act; (6) Continue the design, order materials and continue construction of the COI reinforcement project.

Total, Transmission Services – Capital	**248,234**	**314,145**	**418,851**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Main Grid	
▪ Reflects increase in design, material and construction costs and to accommodate new projects associated with updated power flow study results.	+38,141
Area & Customer Services	
▪ Reflects decrease in design, material and construction costs and to accommodate new customer service projects.	-6,918
Upgrades & Additions	
▪ Reflects decrease on both system wide controls schemes, fiber projects and communications upgrades and improvements and additions to other transmission facilities.	-5,621
System Replacements	
▪ Reflects continuing focus on system replacements.	+25,561
Projects Funded in Advance	
▪ Reflects increase of large customer funded projects related to generation integration.	+53,543
Total Funding Change, Transmission Services - Capital	+104,706

Capital IT & Equipment/Capitalized Bond Premium

Funding Schedule by Activity

(accrued expenditures)
(dollars in thousands)

Capital IT & Equipment/Capitalized Bond Premium	FY 2007	FY 2008	FY 2009
Capital Information Technologies (IT) & Equipment	20,610	31,017	51,123
Capitalized Bond Premium	0	0	0
Total, Capital IT & Equipment/Capitalized Bond Premium	20,610	31,017	51,123

Outyear Funding Schedule

(accrued expenditures)
(dollars in thousands)

	FY 2010	FY 2011	FY 2012	FY 2013
Total, Capital IT & Equipment/Capitalized Bond Premium	54,798	28,363	28,431	29,501

Description

Capital Information Technologies provides for the acquisition of general and some dedicated special purpose capital information technologies, and acquisition of special-use capital and IT equipment in support of Bonneville's strategic objectives. This category also includes BPA efforts to facilitate becoming a highly resilient organization, able to anticipate, withstand and effectively respond to disruptive events affecting it and its partners in the Northwest region. The four main areas of resiliency focus include asset management, emergency management, crisis management and continuity of operations.

As part of a major efficiency effort and in support of the President's Management Initiative on Expanded Electronic Government, BPA is moving its IT infrastructure to a more efficient architecture. This FY 2009 budget incorporates the results of this effort. IT is seeking to eliminate redundancies in tools and applications, establish an agency-wide IT architecture with standardized IT purchasing criteria, standardize software licensing processes and minimize agency liabilities through stronger contracts, improve IT project management, and formulate an agency IT portfolio cost management strategy. The IT estimates in this FY 2009 budget, under Capital Information Technologies and Equipment include all IT functions within the agency except TS grid operations. See the Capital Program – Transmission Services section of this budget for additional discussion of transmission-related IT requirements acquisitions.

Capital equipment provides for the acquisition of general and some dedicated special purchases of capital office furniture and equipment.

Bonneville incurs a bond premium whenever it repays a Treasury bond before the due date. When bonds are refinanced, the bond premiums incurred are capitalized. Historically, Bonneville generally has chosen to finance capitalized bond premiums with bonds issued to the Treasury, as was envisioned in the Transmission System Act of 1974.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Capital Information Technology/Equipment	**20,610**	**31,017**	**51,123**

Includes enhancements to Bonneville's information technology processes to provide cost effective efficiencies for secure, timely and accurate information. Continue enhancements to Bonneville's Enterprise systems that are designed to link key information systems throughout Bonneville and improve business processes. Current efforts include continued functional process improvement in areas not included in the initial development phase. Acquire capital office furniture and equipment, capital automatic data processing (ADP) -based administrative telecommunications equipment, ADP equipment (hardware), and support capital software development for certain Bonneville programs.

Capitalized Bond Premium.	**0**	**0**	**0**

- Continue to assess financial market and when cost-effective, refinance available bonds as prudent.

Total, Capital IT & Equipment/Capitalized Bond Premium	**20,610**	**31,017**	**51,123**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Capital Information Technology & Equipment	
▪ Reflects increasing emphasis on BPA business resiliency efforts.	+20,106
Capitalized Bond Premium	
▪ No change	0
Total Funding Change, Capital Equipment/Capital Bond Premium	**+20,106**

Power Services - Operating Expense

Funding Schedule by Activity

Power Services - Operating Expenses	FY 2007	FY 2008	FY 2009
	(accrued expenditures) (dollars in thousands)		
Production	872,484	1,235,976	1,332,693
Associated Projects Costs	264,883	277,356	286,322
Fish & Wildlife	139,260	143,007	143,007
Residential Exchange	300,581	336,861	337,320
NW Power & Conservation Council	8,390	9,266	9,453
Conservation and Energy Efficiency	61,995	66,387	66,037
Total, Power Services - Operating Expenses	1,647,593	2,068,853	2,174,832

Outyear Funding Schedule

	FY 2010	FY 2011	FY 2012	FY 2013
	(accrued expenditures) (dollars in thousands)			
Total, Power Services - Operating Expense	1,971,328	2,036,896	1,929,150	1,849,540

Description

Production includes all Bonneville non-Federal debt service (including EN debt),O&M of power system generation resources, including a large nuclear plant, business operations, short- and long-term power purchases, electric utility marketing of power, and oversight of hydro and nuclear projects. BPA develops products and services to meet the needs of Bonneville customers and stakeholders, and acquires resources as needed.

During FY 2008, BPA will be developing a long-term resource program to guide future resource acquisitions needed to meet preference customer load growth. This plan is expected to be completed in time for acquisitions to begin as necessary in FY 2009. Once the plan is complete, BPA will modify its budget as needed to reflect expected acquisitions.

EN debt is one of Bonneville's largest expense components. BPA, in collaboration with EN, is pursuing the refinancing of certain EN bonds as part of an ongoing debt optimization program. Through this program, BPA uses the reductions in debt service for its EN bonds to make advance payments on its Federal debt. Advance payment estimates in the 2009 budget include $63 million in FY 2008 and $78 million in FY 2009, consistent with power rate case documentation. Implementation of the refinancing components will be subject to favorable market conditions and interest rate environment.

Bonneville's Power Transacting Risk Management Policy permits the use of power financial instruments to hedge Bonneville's exposure to market price risk and certain index sales contract provisions.

Associated Projects represents funding for operation and maintenance costs for the FCRPS, minor additions, improvements and replacements, and liabilities of the Corps and Reclamation hydroelectric projects in the Pacific Northwest, which serve many purposes. All agencies emphasize efficient power production from existing facilities and improvement of the performance and availability of power generating units. Bonneville pays additional financing costs of the FCRPS facilities through its Interest Expense and Capital Transfer budget programs. Bonneville provides funding for the operations and maintenance costs that are part of the Lower Snake River Compensation Plan (LSRCP) hatcheries. Bonneville is responsible for annual payments to the Confederated Tribes of the Colville Reservation for their claims concerning their contribution to the production of hydropower by the Grand Coulee Dam in accordance with the Settlement Agreement between the United States and the Tribes (April 1994).

Bonneville's Fish and Wildlife Program provides for the protection, enhancement, and mitigation of Columbia River Basin fish and wildlife due to losses attributed to the development and operation of Federal hydroelectric projects on the Columbia River and its tributaries from which Bonneville markets power. Bonneville satisfies a major portion of its fish and wildlife responsibilities pursuant to Section 4(h) of the Northwest Power Act by funding projects and activities designed to be consistent with the Council Fish and Wildlife Program.

Bonneville is also mandated to implement measures called for under the ESA. These measures are part of the most recent biological opinions issued in November 2004 by NOAA Fisheries (2004 Biop) and in 2006 by the USFWS (2006 Biop) to address the effects of the operation of the FCRPS on threatened and endangered salmon, steelhead, Kootenai River white sturgeon, and bull trout. The biological opinions require the FCRPS Action Agencies to implement actions in the Columbia River Basin that address impacts of the Federal hydrosystem on ESA-listed fish to ensure that operation of the FCRPS does not jeopardize the continued existence of listed species or adversely modify their designated critical habitat. In February 2005, the FCRPS Action Agencies published an implementation plan for their proposed action addressed in the NOAA Fisheries 2006 Biological Opinion. The implementation plan, together with projects undertaken to address mitigation for non-listed species under the Northwest Power Act, and those to address requirements of the USFWS 2006 Biological Opinion form the basis for Bonneville's planned capital investment of $36 million for FYs 2008 and 2009.

The 2004 BiOp was also challenged in Federal District Court. In October 2005, the District Court invalidated the 2004 BiOp, although leaving it "in place" during the remand period. The Judge also ordered the sovereign parties to collaborate during the remand process, to try to find an acceptable approach for the 2004 BiOp that would have regional support. In December, the Department of Justice filed a notice to appeal the District Court's October 2005 remand order. However, the Federal parties continue to support the court ordered collaboration on the 2004 BiOp, even though an appeal has been filed. In response to litigation seeking injunctive relief on the FCRPS in 2006, the Court approved the Federal spill plan with two modifications. In 2006 (the timeframe of the injunction), the FCRPS continued to spill during late spring and late August. The 2007 spill plan largely repeats the 2006 plan. The collaboration process has continued to make progress over the past two years and is now scheduled to be completed by spring 2008 when BPA anticipates NOAA Fisheries will complete a final FCRPS BiOp. Additional proposals to be implemented during FY 2009, if any, resulting from the completion of the remand collaboration process (by spring of 2008) requiring expenditures above and beyond the $143 million in expense and $36 million in capital are uncertain at this time.

There has also been litigation directed at the USFWS Biological Opinions for Libby dam. In 2003, the Corps and BPA reinitiated consultation for the operations at Libby dam to address impacts to recently designated critical habitat for the Kootenai River white sturgeon, and to evaluate information that had been developed on Kootenai River white sturgeon and bull trout since the 2000 USFWS BiOp. That consultation was completed in February 2006, but was challenged by environmental groups, the Kootenai Tribe, and the State of Montana in Federal district court of Montana. However these parties have reached tentative agreement on a long term plan of recovery efforts including a combination of hatchery, habitat and flow regimes that can be implemented by BPA, Corps, Kootenai Tribe, State of Montana and others.

Bonneville's fish and wildlife expenditures will focus on activities that benefit Columbia River Basin fish and wildlife resources including projects, consistent with priorities established in Council Subbasin Plans, designed to:

- increase survival of ESA-listed and non-listed fish at FCRPS dams and reservoirs;
- increase survival of ESA-listed and non-listed fish throughout their life cycle by protecting and enhancing important habitat areas;
- reform hatchery practices that affect ESA-listed populations and use hatcheries to contribute to conservation and recovery of ESA-listed and non-listed fish;
- provide for offsite mitigation projects for habitat, passage, and other improvements that address limiting factors for target species as defined in Subbasin Plans;
- reduce harvest-related mortality on ESA-listed and non-listed fish and support sustainable fisheries; and;
- support a focused and well-coordinated research, monitoring, and evaluation program.

To the extent possible, Bonneville is integrating the actions implemented in response to the FCRPS Biological Opinions with projects implemented under the Council's Fish and Wildlife Program. Subbasin Plans that include prioritized strategies for mitigation actions will help guide project selection that meets both BPA's ESA and Northwest Power Act responsibilities. Discussion of a minimum cost-sharing requirement for certain fish and wildlife projects that BPA and other entities together share authority to fund is continuing in currently ongoing discussions with the Council and the regional fish and wildlife manager, customers, and Tribes. BPA established a Cost Sharing MOU with the US Forest Service in FY 2007 that requires a programmatic 30 percent cost share for fish mitigation projects funded by BPA on US Forest Service lands.

The FY 1997 Energy and Water Development Appropriations Act added section 4(h)(10)(D) to the Northwest Power Act, directing the Council to appoint an Independent Science Review Panel (ISRP) "to review a sufficient number of projects" proposed to be funded through Bonneville's fish and wildlife budget "to adequately ensure that the list of prioritized projects recommended is consistent with the Council's program," The Northwest Power Act further states that " . . . in making its recommendations to Bonneville, the Council shall consider the impact of ocean conditions on fish and wildlife populations; and shall determine whether the projects employ cost effective measures to achieve program objectives." The Conference Report on the FY 1999 Energy and Water Development Appropriations Act included a new assignment for the ISRP and the Council. The ISRP was to review the fish and wildlife projects, programs, or measures included in Federal agency budgets that are reimbursed, and/or directly funded, by Bonneville. The ISRP was directed to determine whether the proposals are consistent with the scientific criteria in the Northwest Power Act as amended in 1996, and provide a report to the Council by

April 1 of each year. The Council, in turn, must report to the Congress annually by May 15. Consequently, projects funded by Bonneville under the Program typically receive ISRP review as part of the Council recommendation process.

The REP was created through the Northwest Power Act to extend the benefits of low-cost Federal power to the residential and small farm customers of Pacific Northwest electric utilities that meet certain conditions. The 1996 Comprehensive Regional Review recommended that Bonneville engage in settlement discussions regarding the REP. Bonneville then developed a Subscription Strategy based on the recommendations of the Comprehensive Review. That Strategy proposed a comprehensive settlement of REP disputes with IOUs in the Pacific Northwest, which resulted in new contracts with regional IOUs that provided power and monetary benefits to their residential and small farm customers.

The 2000 REP Settlement Agreements, as amended, and the way the settlement costs were allocated in setting the PF rate for FY 2002-06, were challenged by public utilities and others in the U.S. Court of Appeals for the Ninth Circuit. The PF rate is the cost-based rate that preference customers pay for their requirements purchases from BPA On May 3, 2007, the Court held that the REP Settlement Agreements were inconsistent with the Northwest Power Act and that the settlement costs were improperly allocated in setting the PF rate.

As a result of these Court rulings, payments to the IOUs were suspended in May, 2007. Regional discussions continue that could lead to a recommendation to BPA on how best to implement a Residential Exchange Program, beginning in FY 2009. However, the PF rate remains unchanged in the meantime. BPA is planning a section 7(i) rate proceeding during FY 2008 to revise FY 2009 power rates, as well as a public process to review and revise the 1984 Average System Cost Methodology, to respond to the Court's rulings. These processes are expected to conclude in 2008.

The Council's major activities include the periodic preparation of a Northwest Conservation and Electric Power Plan (a 20-year electric energy demand and resources forecast and energy conservation program) and a Columbia River Basin Fish and Wildlife Program of loss mitigation and resource enhancement actions. The Northwest Power Act directs that expenses of the Council, subject to certain limits based on forecasted Bonneville power sales, shall be included in Bonneville's annual budget to Congress. Funding for the Council is provided by Bonneville and is recovered through Bonneville power rates.

BPA will acquire conservation resources consistent with the Council's Power Plan and act as a catalyst for energy efficiency. Such action will: 1) meet conservation targets; 2) achieve a least cost resource mix; 3) dampen the cost impacts of power purchases; 4) avoid the costs of ramping programs and infrastructure up and down; 5) extend the value of the FCRPS to customers; and 6) build the region's resource portfolio with conservation**.** Bonneville also is exploring how best to integrate demand-side management, distributed generation, and other leading edge technologies (i.e., Energy Web program and non wires solutions) into its transmission planning process.

Detailed Justification

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Production	**872,484**	**1,235,976**	**1,332,693**

- Power Purchases: Includes purchased power to cover power supply obligations as well as balancing the hydro system. These purchases can be made in the form of long-term purchases to meet supply obligations based on long-term planning requirements or they can be made within the year due to the monthly shape of the loads and the monthly shape of the hydro electric generation. Also, purchases can be made within the month and within the day to fill shortages due to fluctuations in the hydro system and load changes.

- Power Scheduling/Marketing: Schedule and market (buy/sell) electric energy with Bonneville customers and the Pacific Northwest's interconnected utilities. Scheduling includes PS's implementation of physical and memo power schedules and associated transmission schedules, implementation of Electronic Tagging (ETag) in accordance with NERC and in accordance with FERC, implementation of electronic scheduling and the Columbia Grid as it evolves.

- Trojan: Decommissioning activities are complete and the Trojan operating license has been terminated by the NRC. BPA's 30 percent share of the demolition of buildings and site restoration activities will continue into FY 2008. Operation and maintenance for the Independent Spent Fuel Storage Installation Project will continue for FYs 2008-2010.

- Columbia Generating Station (formerly WNP-2): Continue to acquire full capability of Columbia Generating Station (Columbia). Columbia is on a 24-month fuel and outage cycle. A maintenance and refueling outage occurred in FY 2007 and is planned for FY 2009.

- WNP-1/WNP-3: Continue to fulfill contractual obligations for WNP-1 and WNP-3.
- Long-Term Power Purchases and Wheeling: Continue to acquire 100 percent of the 18.6 MW output of the Foote Creek 2 and 4 wind projects and a 15 kW share of the output from the Solar Ashland Project. Continue to acquire 90 MW of Stateline wind project. Continue to acquire 100 percent of the output of the Condon and Klondike wind projects.

Generation and Oversight:

FY 2007: Continue to provide oversight of all contracts signed to date. Provide oversight of large thermal generating plants from which Bonneville purchases capability to ensure that all Bonneville approval rights are protected; coordinate, communicate, and administer agreements, issues, and programs between Bonneville and the project owners. Continue to provide wind resource integration services for customer wind generation.

(dollars in thousands)

FY 2008: Continue to provide oversight of all contracts signed to date. Pursue acquisition of cost effective renewable generation to meet load growth. Work with regional stakeholders to determine which (if any) products, actions or investments BPA should pursue to best facilitate renewable development in the Pacific Northwest. Continue to provide oversight on the wind resource integration services purchased by requirements customers.

FY 2009: Continue to provide oversight of all contracts signed to date. Continue to provide wind resource integration services for customer wind generation.

Associated Project Costs	**264,883**	**277,356**	**286,322**

- Support FCRPS project costs and work to strengthen interagency and regional relationships to improve project performance, supporting functions, and to better understand project resource requirements and costs. This helps to maintain FCRPS reliability and system performance, as well as to attain BPA's strategic business objectives.

- Bureau of Reclamation:
  FY 2007: Continued direct funding Reclamation O&M power activities.
  FY 2008: Continue direct funding Reclamation O&M power activities.
  FY 2009: Continue direct funding Reclamation O&M power activities.

- Corps of Engineers:
  FY 2007: Continued direct funding Corps O&M power activities.
  FY 2008: Continue direct funding Corps O&M power activities.
  FY 2009: Continue direct funding Corps O&M power activities.

Fish and Wildlife	**139,260**	**143,007**	**143,007**

- Specific project solicitation recommendations were made by the Council in late 2006 followed by BPA review and funding decisions completed in early 2007. These decisions were based upon the management objectives and priorities in the Subbasin Plans as well as an integration of ESA responsibilities as described in the NOAA Fisheries and US Fish and Wildlife Service's FCRPS Biological Opinions. Coordination continues among BPA, Council, Federal, State, Tribes and others as the FCRPS remand collaborative process continued in FY 2007 with an expected outcome for a new FCRPS BiOp from NOAA Fisheries by spring 2008.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

- Anadromous Fish: Continue implementing both ongoing and new projects that support ESA-listed species and other measures called for under the 2004 BiOp and amended FCRPS Action Agency proposal, consistent with the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion. Prioritize projects that address the factors that limit mitigation success as identified in the Subbasin Plans and that fulfill BPA's responsibility for mitigation of the FCRPS. Implement and develop activities that protect and enhance tributary and estuary habitat; improve mainstream habitat on an experimental basis; reduce potentially harmful hatchery practices on ESA-listed populations; and contribute to sustainable fisheries. These activities have been selected in response to the Northwest Power Act section 2(6) to "protect, mitigate and enhance fish and wildlife including related spawning grounds and habitat on the Columbia River and its tributaries."

- Resident Fish: Implement activities to determine the impacts of the FCRPS on bull trout and mitigate for those impacts, and promote the reproduction and recruitment of Kootenai River white sturgeon. These activities have been selected in response to the USFWS 2000 Biological Opinion and the Northwest Power Act requirement to "protect, mitigate and enhance fish and wildlife including related spawning grounds and habitat on the Columbia River and its tributaries."

- Continue mitigation in resident fish for anadromous losses (substitution), mitigation for reservoir operation impacts to resident fish, and continue to refine, quantify, and delineate the difference between the two. Those resident fish acquisition projects that meet BPA's capitalization policy will be funded under the capital portion of Bonneville's fish and wildlife budget.

- Wildlife: Use existing Bonneville policies to continue the current program including funding for wildlife actions resulting from Council Fish and Wildlife Program amendments for wildlife mitigation. These activities have been selected in response to the Northwest Power Act requirement to "protect, mitigate and enhance fish and wildlife including related spawning grounds and habitat on the Columbia River and its tributaries." Those wildlife acquisition projects that meet BPA's capitalization policy will be funded under the capital portion of Bonneville's fish and wildlife budget.

Residential Exchange	**300,581**	**336,861**	**337,320**

- Includes negotiated contract settlement agreement costs for monetary benefits and forecasts of possible public exchange costs.

Northwest Power and Conservation Council	**8,390**	**9,266**	**9,453**

- Continue support of the Council activities, as directed under the Northwest Power Act, including regional power plan development and maintenance, and fish and wildlife program activities.

	FY 2007	FY 2008	FY 2009
	(dollars in thousands)		
Conservation and Energy Efficiency	**61,995**	**66,387**	**66,037**

- Continue close-out of the legacy conservation resource acquisition contracts, which support Bonneville's contractual obligation to serve customer load growth.

- Provide credible, unbiased information or technical or financial support to conservation purposes. As an agency with independent responsibilities based on its authorizing legislation, Bonneville has a statutory responsibility to provide support to certain conservation objectives that are governmental in nature, such as assisting in the development of emerging technologies and providing unbiased information to consumers. Bonneville is participating with other regional entities to support market transformation and development activities that meet the needs of Bonneville customers and create business opportunities for the private sector in the Pacific Northwest.

	FY 2007	FY 2008	FY 2009
Total, Power Services – Operating Expense	**1,647,593**	**2,068,853**	**2,174,832**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Production	
■ Primarily reflects increases in power purchases and CGS O&M	+96,717
Associated Project Costs	
■ Reflects minor changes to security, biological opinion requirements, and improvements, replacements, and minor additions at the projects.	+8,966
Fish and Wildlife	
■ Consistent funding levels reflect funding associated with Biological Opinion and Northwest Power Act activities.	0
Residential Exchange	
■ Increase due to increase in forecast of public exchange costs.	+459
Northwest Power and Conservation Council	
■ Small increase reflects continuing Council program activities.	+187

	FY 2009 vs. FY 2008 ($000)
Conservation and Energy Efficiency	
▪ Small decrease reflects normal program adjustments.	-350
Total Funding Change, Power Services - Operating Expense	**+105,979**

Transmission Services - Operating Expense

Funding Schedule by Activity

Transmission Services - Operating Expense	FY 2007	FY 2008	FY 2009
	(accrued expenditures) (dollars in thousands)		
Engineering	42,685	58,668	70,155
Operations	103,733	102,086	103,287
Maintenance	139,983	139,842	141,585
Total, Transmission Services - Operating Expense	286,401	300,596	315,027

Outyear Funding Schedule

	FY 2010	FY 2011	FY 2012	FY 2013
	(accrued expenditures) (dollars in thousands)			
Total, Transmission Services - Operating Expense	321,696	330,184	336,271	342,504

Description

This activity provides for the transmission system services of engineering, operations, and maintenance for Bonneville's electric transmission system, consisting of over 15,000 circuit miles (24,135 circuit kilometers) of lines, 237 substations, and the associated power system control and communication facilities, with an invested cost of more than $6.0 billion. Primary strategies of this program are: 1) maintain the safety and reliability of the transmission system; 2) increase the focus on customers; 3) optimize the transmission system; and 4) provide open and nondiscriminatory transmission access; and 5) improve Bonneville's cost effectiveness.

Detailed Justification

	FY 2007	FY 2008	FY 2009
	(dollars in thousands)		
Engineering	**42,685**	**58,668**	**70,155**

Continue efforts to identify best methods for improving system reliability and maintenance practices, and continue cost reduction efforts by identifying opportunities for low-cost reinforcement and voltage support of the existing transmission system.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009

- R&D: Conduct in-house transmission system research and development, including (1) studies on reliability, High Voltage Direct Current (HVDC) and High Voltage Alternating Current (HVAC) outage reduction, and (2) methods to update existing facilities and reduce maintenance costs including reliability-centered monitoring and recording methods for analysis.

- Technical Support: Provide technical support activities, such as transmission system planning and studies to optimize portions of the system. Provide support for non-wires solutions studies and pilot projects.

- Capital-to-Expense Adjustments: Conduct annual analysis of Bonneville's outstanding capital work orders to assess whether they should be expensed.

- Reimbursable Transactions: Enter into written agreements with Federal and non-Federal entities that have work or services to be performed by Bonneville staff at the expense of the benefiting utilities. The projects must be beneficial, under agreed upon criteria, to Bonneville operations and to the Federal or non-Federal entity involved. Additionally, these activities contribute to more efficient or reliable construction of the Federal transmission system or otherwise enhance electric service to the region.

- Leased and Other Costs: Includes leases and other costs of transmission, delivery and voltage support facilities when such arrangements are operationally feasible and cost effective to deliver power. Other costs included are the debt service costs associated with Large Generator Interconnection Agreements (LGIA).

Operations	**103,733**	**102,086**	**103,287**

- FY 2007: Continued to operate within parameters of regional transmission authorities. Prepared for increased complexity of outage scheduling, transmission scheduling, and dispatching, as well as impact of an expected high attrition rate of skilled operation dispatching workforce by recruiting and training apprentices and skilled replacements. Continued development and implementation of business systems and tools. Participated in planning and preparation for establishment of Columbia Grid.

- FY 2008: Continue to operate within parameters of regional transmission authorities. Continue preparation for increased complexity of outage scheduling, transmission scheduling, and dispatching, as well as impact of an expected high attrition rate of skilled operation dispatching workforce by recruiting and training apprentices and skilled replacements. Continue development and implementation of business systems and tools. Participate in continued planning and preparation of Columbia Grid.

(dollars in thousands)		
FY 2007	FY 2008	FY 2009

- FY 2009: Continue to operate within parameters of regional transmission authorities. Continue preparation for increased complexity of outage scheduling, transmission scheduling, and dispatching, as well as impact of an expected high attrition rate of skilled operation dispatching workforce by recruiting and training students, apprentices, and skilled replacements. Continue development and implementation of business systems and tools. Participate in planning and preparation for establishment of Columbia Grid.

- Substation Operations: Perform operations functions necessary to provide electric service to customers and to protect the Federal investment in electric equipment. Includes equipment adjustments, switching lines and equipment during emergencies or maintenance, isolating damaged equipment, restoring service to customers, and inspecting equipment, reading meters, et cetera.

- Power System Control and Dispatching: Perform central dispatching, control, and monitoring of the electric operation of the Federal transmission system. Also includes load, frequency, and voltage control of Federal generating plants, and operation of the system control and data computers at Dittmer and Munro Control Centers.

- Marketing and Sales: Provide management and direction of transmission rates, and provide business strategy in marketing of transmission and ancillary products and services of Transmission Services. Involve customers and constituents in the process of product and rate development. Maintain accurate and complete historical records of current and past transmission agreements. Provide guidance for current and future transmission contract negotiations. Provide financial analysis of market strategies. Monitor and report on the financial health of transmission services. Support cost management by effective reporting and analysis of current expenditures. Ensure official budget submittals reflect current management financial strategies and adequately fund transmission programs.

- Transmission Scheduling: Provide open access to the Federal transmission system consistent with the Open Access Transmission Tariff approved by FERC. Schedule and market transmission capacity to Bonneville customers, California ISO, and Pacific Northwest's interconnected utilities. Manage the reservations and scheduling of all transmission services associated with the Open Access Transmission Tariff.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
Maintenance	**139,983**	**139,842**	**141,585**

In all aspects of maintenance, Bonneville is continuing the implementation of RCM practices. This change is focused on improving system reliability and increasing availability in a deregulated market. Access road maintenance costs are expected to increase dramatically as Bonneville addresses the aging roads system and environmental constraints associated with construction, enhancement, and maintenance of access roads. The Bonneville transmission system encompasses approximately 50,000 miles of access roads (many of these roads are through rugged, inaccessible terrain).

- FY 2007: Continued to refine RCM practices at all of Bonneville's O&M regions. Continued to improve performance meeting System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) targets. Continued efforts to achieve the SAIFI and SAIDI targets of no control chart violations for circuit importance categories 1-2 (highest importance), and not more than one violation for category 4. Control charts are statistically based graphs that illustrate variability in performance. Continued to improve availability performance in a deregulated market by utilizing more efficient and cost-effective maintenance work practices and outage coordination. Used recruitment incentives to ensure succession of the current work force and remain competitive as an employer in the utility industry. Assured a safe work environment through safety awareness and improved work practices. Increased outage scheduling planning to increase customer satisfaction. Continued high levels of vegetation management and increased access road work to provide reliable access to facilities and ensure environmental compliance.

- FY 2008: Continue to refine RCM practices at all of Bonneville's O&M regions. Continue to improve performance to meet SAIFI and SAIDI targets as explained above. Continue to improve system availability performance through new maintenance procedures and work practices. Continue to prepare for the impact of an expected high attrition rate among Bonneville's aging workforce by recruiting apprentices and replacements for critical minimum crew size workload positions. Increase outage scheduling and coordination planning to increase customer satisfaction and system availability. Increase emphasis on non-electric facilities to compensate for years of deferral. Continue high emphasis of vegetation management, implementation of an aggressive access road management plan to maintain roads at a level that minimizes response time, increases reliability, and ensures environmental compliance.

(dollars in thousands)		
FY 2007	FY 2008	FY 2009

- FY 2009: Continue to improve performance to meet SAIFI and SAIDI targets as explained above. Continue to improve system availability performance through new maintenance procedures and work practices. Continue to prepare for the impact of an expected high attrition rate among Bonneville's aging workforce by recruiting apprentices and replacements for critical minimum crew size workload positions. Increase outage-scheduling planning and coordination to increase customer satisfaction and system availability. Maintain vegetation management levels to ensure system reliability. Continue access road work to provide reliable access to facilities and ensure environmental compliance.

- Transmission Line Maintenance: Maintain and repair over 15,000 circuit miles (24,135 km) of high voltage transmission lines, of which over 6,436 km (4,000 circuit miles) are 500-kV transmission EHV (extra-high voltage), for which maintenance is two and one-half times more labor-intensive than maintenance of lower transmission voltages, although more efficient in transmission of power. This responsibility includes maintaining transmission rights-of-way to ensure system reliability, safety, and environmental compliance. Adopt work practices that improve system availability and reliability.

- Substation Maintenance: Maintain and repair the transmission system power equipment located in Bonneville's 238 substations. Work includes inspections, diagnostic testing and predictive and condition based maintenance.

- System Protection Maintenance: Maintain relaying metering and remedial action scheme equipment used to control and protect the electrical transmission system and to meter energy transfers for the purpose of revenue billing. Additionally, field-engineering services provide technical advice and assure the correct operation of power system relaying and special control systems used to support interregional energy transmission capabilities.

- Power System Control Maintenance: Test, repair, and provide field engineering support of Bonneville's highly complex equipment, communications, and control systems, including seven major microwave systems, fiber optic systems, and other critical communications and control equipment that support the power system.

- Non-Electric Plant Maintenance: Maintain Bonneville's non-electric facilities. Includes site, building, and building utility maintenance; custodial services; station utility; and other maintenance service activities on Bonneville-owned or Bonneville-leased non-electric facilities.

	(dollars in thousands)		
	FY 2007	FY 2008	FY 2009
▪ Maintenance Standards and Engineering: Establish, monitor, and update system maintenance standards, policies, and procedures, and review and update long-range plans for maintenance of the electric power transmission system.			
Total, Transmission Services - Operating Expense	**286,401**	**300,596**	**315,027**

Explanation of Funding Changes

	FY 2009 vs. FY 2008 ($000)
Engineering	
▪ Reflects emphasis on system reliability improvements, research and development, and an increase in the debt service for the LGIA program.	+11,487
Operations	
▪ Reflects continued emphasis on security and control center systems support.	+1,201
M**aintenance**	
▪ Primarily reflects continuing maintenance program activities, including system protection, right-of-way, line maintenance, and performance improvements.	+1,743
Total Funding Change, Transmission Services – Operating Expense.	**+ 14,431**

Interest, Pension and Post-retirement Benefits - Operating Expense and Capital Transfers

Funding Schedule by Activity

(accrued expenditures)
(dollars in thousands)

Interest, Pension and Post-retirement Benefits	FY 2007	FY 2008	FY 2009
BPA Bond Interest (Net)	127,985	67,281	89,394
BPA Appropriation Interest	44,665	40,793	38,611
Corps of Engineers Appropriation Interest	162,186	163,744	157,655
Lower Snake River Comp Plan Interest.	16,485	16,466	16,466
Bureau of Reclamation Appropriation Interest	43,376	43,247	43,247
Subtotal, Interest – Operating Expense	394,697	331,531	345,373
Pension and Post-retirement Benefits	21,100	18,000	30,652
Total, Interest, Pension and Post-retirement Benefits	415,797	349,531	376,025

Outyear Funding Schedule

(accrued expenditures)
(dollars in thousands)

	FY 2010	FY 2011	FY 2012	FY 2013
Total, Interest, Pension and Post-retirement Benefits	402,570	422,136	442,763	475,449

Operating Expense

Description

Interest expense provides for the payment of interest due on Federal debt. This consists of capital investment in FCRPS hydroelectric generating and transmission facilities of Bonneville, the Corps and Reclamation. Investments were financed by Congressional appropriations and Bonneville borrowings from the Treasury. Bonneville repays Federal debt through its power sales and transmission services revenues.

Since receiving Treasury borrowing authority in 1974 under the Transmission System Act, all Bonneville borrowing has been at market rates. As of Oct 1, 1996, all of Bonneville's repayment obligations on FCRPS appropriated investment (Corps and Reclamation FCRPS investment and Bonneville investment) financed with appropriations prior to the Transmission System Act that were unpaid as of Sept 30, 1996, were restructured and assigned new current-market interest rates. The Bonneville Appropriations Refinancing Act of 1996 called for resetting (reducing) the unpaid principal of FCRPS appropriations and reassigning (increasing) interest rates. New principal amounts were established as of the beginning of FY 1997 at the present value of the principal and annual interest payments Bonneville would make to the Treasury for these obligations in the absence of the legislation, plus $100 million. The new principal amounts are then assigned new interest rates based on the Treasury yield curve rates prevailing at the end of FY 1996. Bonneville’s outstanding repayment obligations on appropriations at the end of FY 1996 were $6.7 billion with a weighted average interest rate of 3.4 percent. The refinancing reduced the principal amount to $4.1 billion with a weighted average interest rate of 7.1 percent. Implementation of the refinancing took place in 1997 after audited actual financial data was available. As called for in the legislation, Bonneville submitted its calculations and interest rate assignments implementing the Bonneville Appropriations Refinancing Act to Treasury for their review and approval. Treasury approved the implementation calculations in July 1997. The Act also calls for all future FCRPS appropriations to be assigned prevailing Treasury yield curve interest rates.

Interest estimates are a direct function of costs of Treasury borrowing to Bonneville, repayment status of outstanding FCRPS investments, and projected additions to FCRPS plant in service. These estimates may change over time depending on forecasted market conditions. The interest cost estimates below include the impact of Bonneville's appropriation refinancing legislation.

Bonneville has been paying its unfunded liability of the Civil Service Retirement System (CSRS) and post-retirement benefits into the General Fund of the Treasury (receipt account 892889) since FY 1998. These payments are consistent with the FY 2001 Administration's budget which assumed Bonneville would prospectively cover the full unfunded liability that accrues in fiscal years after FY 1997 of the Civil Service Retirement and Disability Fund (Disability Fund), the Employees Health Benefits Fund (Health Fund), and the Employees Life Insurance Fund (Insurance Fund) that it had not covered prior to FY 1998. As part of the FY 2001 Administration's Budget, Bonneville assumed its entire CSRS cost recovery would be phased in over a 10-year period, given that wholesale power and transmission rates for Bonneville were contractually frozen until the end of FY 2001, in order to meet competitive market pressures. The Additional Post-Retirement Contribution for FY 2007, in the amount of $21.1 million, includes the final payment on deferred amounts including interest, that accrued between FY 1998 and FY 2001 when power rates were frozen. For FY 2008, the final year of the scheduled 10-year period, and for FY 2009, $18.0 million and $30.5 million, respectively, are assumed to be recovered by Bonneville through rates and paid into the General Fund of the Treasury. Post FY 2008 amounts are unscheduled estimates and may change. Cost estimates include pension and post-retirement benefits for Bonneville and the power-related portion of the Corps, Reclamation, and USFWS.

Capital Transfers

Funding Schedule by Activity

Capital Transfers	FY 2007	FY 2008	FY 2009
	(accrued expenditures) (dollars in thousands)		
BPA Bond Amortization	506,300	241,419	258,770
Reclamation Appropriation Amortization	229	0	0
BPA Appropriation Amortization	54,157	30,662	6,878
Corps Appropriation Amortization	57,714	136,183	10,075
Total, Capital Transfers	623,400	408,264	275,723

Outyear Funding Schedule

	FY 2010	FY 2011	FY 2012	FY 2013
	(accrued expenditures) (dollars in thousands)			
Total, Capital Transfers	423,976	417,680	293,841	246,661

Description

This activity conveys funds to the Treasury for repayment of certain FCRPS costs not included in the Associated Project Costs budget. Since capital transfers are cash transactions, they are not considered budget obligations.

BPA Amortization/Capital Transfers for FY 2007 includes final payment to Treasury for reimbursement of judgment funds, consistent with the Enron settlement agreement in 2003.

BONNEVILLE POWER ADMINISTRATION
TOTAL OBLIGATIONS/OUTLAYS
Current Services
(in millions of dollars)
FB 23-Jan-08
FISCAL YEAR

BP-1 SUMMARY	**2007**		**2008**		**2009**		**2010**	**2011**	**2012**	**2013**
1,3/	**Oblig.**	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Oblig.**	**Oblig.**	**Oblig.**
1 Residential Exchange	301	301	337	337	337	337	300	300	171	171
2 Power Services 2/	1,137	1,137	1,513	1,513	1,619	1,619	1,450	1,515	1,531	1,451
3 Transmission Services	427	427	543	543	609	609	600	700	755	663
4 Conservation & Energy Efficiency	69	69	108	108	108	108	109	109	119	119
5 Fish & Wildlife	174	174	179	179	179	179	179	179	179	179
6 Interest/ Pension 4/	416	416	350	350	376	376	403	422	443	475
7 Associated Project Cost - Capital	108	108	159	159	137	137	143	148	153	158
8 Capital Equipment	21	21	31	31	51	51	55	27	27	28
3 Planning Council	8	8	9	9	9	9	10	10	10	10
10 Misc. Accounting Adjs.	0	0	0	0	0	0	0	0	0	0
11 Projects Funded in Advance	107	107	72	72	125	125	66	79	72	73
12 Capitalized Bond Premiums	0	0	0	0	0	0	0	2	2	2
13 Misc. Accounting Adjs.	0									
TOTAL OBLIGATIONS/ OUTLAYS 3/	**2,768**	**2,768**	**3,301**	**3,301**	**3,550**	**3,550**	**3,315**	**3,491**	**3,462**	**3,329**

REVENUES AND REIMBURSEMENTS

Current Services

(in millions of dollars)

FISCAL YEAR

BP-1 SUMMARY	2007		2008		2009		2010	2011	2012	2013
	Oblig.	Outlays	Oblig.	Outlays	Oblig.	Outlays	Oblig.	Oblig.	Oblig.	Oblig.
13 Revenues 5/	3,214	3,214	3,221	3,221	3,424	3,424	3,250	3,413	3,400	3,266
14 Project Funded in Advance	107	107	72	72	125	125	66	79	72	73
15 **TOTAL**	**3,321**	**3,321**	**3,293**	**3,293**	**3,549**	**3,549**	**3,316**	**3,492**	**3,472**	**3,339**
BUDGET AUTHORITY (NET) 6/	**(312)**		**26**		**12**		**22**	**8**	**(7)**	**(10)**
16 **OUTLAYS (NET) 6,7/**		**(508)**		**42**		**23**	**30**	**17**	**(4)**	**(10)**

The accompanying notes are an integral part of this table.

1/ This FY 2009 budget includes capital and expense estimates for PS based on forecasted FY 2007 Final Power Rate Proposal and associated outyear estimates for FYs 2010-2013. The TS capital and expense estimates are based on forecasted Transmission 2008 Rate Case estimates and associated outyear estimates for FYs 2010-2013.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2009 budget have been updated to reflect executive management decisions from BPA's Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

2/ Power Services includes Fish & Wildlife, Residential Exchange, Planning Council, Conservation & Energy Efficiency and Associated Project Costs which have been shown separately for display purposes.

3/ This budget has been prepared in accordance with the Budget Enforcement Act (BEA) of 1990. Under this Act all BPA budget estimates are treated as mandatory and are not subject to the discretionary caps included in the BEA. These estimates support activities which are legally separate from discretionary activities and accounts. Thus, any changes to BPA estimates cannot be used to affect any other budget categories which have their own legal dollar caps. Because BPA operates within existing legislative authority, BPA is not subject to a Budget Enforcement "pay-as-you-go" test regarding its revision of current-law funding estimates.

4/ See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

5/ Revenues, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools, including upcoming rate adjustment mechanisms, a net revenue risk adjustment, debt service refinancing strategies and/or short-term financial tools to manage net revenues and cash. Some of these potential tools will reduce costs rather than generate revenue, causing the same Net Outlay result. Adjustments for depreciation and 4(h)(10)(C) credits of the NW Power Act are also assumed.

6/ BPA received $49 million of additional budget authority in FY 2007 to accommodate the work necessary to relocate the radio spectrum consistent with the Commercial Spectrum Enhancement Act (P.L. 108-494). In subsequent years, per the assumed expenditures developed as part of BPA's work plans, outlays for the work performed are assumed.

7/ Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that, along with actual market conditions, will impact revenues and expenses. Actual Net Outlays are volatile and are reported in SF-133. Estimated Net Outlays could change due to changing market conditions, streamflow variability, and continuing restructuring of the electric industry.

EXPENSED OBLIGATIONS/OUTLAYS 1,4/
Current Services
(in millions of dollars)
FISCAL YEAR

	2007		2008		2009		2010	2011	2012	2013
	Oblig.	Outlays	Oblig.	Outlays	Oblig.	Outlays	Oblig.	Oblig.	Oblig.	Oblig.
1 Residential Exchange	301	301	337	337	337	337	300	300	171	171
2 Power Services 2/	1,137	1,137	1,513	1,513	1,619	1,619	1,450	1,515	1,531	1,451
3 Transmission Services	286	286	301	301	315	315	322	330	336	343
4 Conservation & Energy Efficiency	62	62	66	66	66	66	69	69	74	74
5 Fish & Wildlife	139	139	143	143	143	143	143	143	143	143
6 Interest/ Pension 3/	416	416	350	350	376	376	403	422	443	475
7 Planning Council	8	8	9	9	9	9	10	10	10	10
8 TOTAL EXPENSE	2,349	2349	2719	2719	2865	2865	2697	2789	2708	2667
10 Projects Funded in Advance	107	107	72	72	125	125	66	79	72	73

CAPITAL OBLIGATIONS/OUTLAYS
Current Services
(in millions of dollars)
FISCAL YEAR

BP-2 continued	2007		2008		2009		2010	2011	2012	2013
	Oblig.	Outlays	Oblig.	Outlays	Oblig.	Outlays	Oblig.	Oblig.	Oblig.	Oblig.
Conservation & Energy Efficiency	7	7	42	42	42	42	40	40	45	45
11 Transmission Services	141	141	242	242	294	294	278	370	419	320
12 Associated Project Cost	108	108	159	159	137	137	143	148	153	158
13 Fish & Wildlife	35	35	36	36	36	36	36	36	36	36
14 Capital Equipment	21	21	31	31	51	51	55	27	27	28
15 Capitalized Bond Premiums	0	0	0	0	0	0	0	2	2	2
16 **TOTAL CAPITAL INVESTMENTS \5**	**312**	**312**	**510**	**510**	**560**	**560**	**552**	**623**	**682**	**589**
17 **TREASURY BORROWING AUTHORITY TO FINANCE CAPITAL OBLIGATIONS 4,5/**	**312**		**510**		**560**		**552**	**623**	**682**	**589**
18 **TREASURY BORROWING AUTHORITY TO FINANCE OTHER OBLIGATIONS**	**3**		**(76)**		**(272)**		**(106)**	**(199)**	**(396)**	**(352)**
19 **ADJUSTED PERMANENT AUTHORITY TO BORROW:**	**315**		**434**		**288**		**446**	**424**	**286**	**237**

The accompanying notes are an integral part of this table.

1/ This FY 2009 budget includes capital and expense estimates for PS based on forecasted FY 2007 Final Power Rate Proposal and associated outyear estimates for FYs 2010-2013. The TS capital and expense estimates are based on forecasted Transmission 2008 Rate Case estimates and associated outyear estimates for FYs 2010-2013.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2009 budget have been updated to reflect executive management decisions from BPA's Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

2/ Power Services includes Fish & Wildlife, Residential Exchange, Planning Council, Conservation & Energy Efficiency and Associated Project Costs which have been shown separately for display purposes.

3/ See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

4/ This budget has been prepared in accordance with the Budget Enforcement Act (BEA) of 1990. Under this Act all BPA budget estimates are treated as mandatory and are not subject to the discretionary caps included in the BEA. These estimates support activities which are legally separate from discretionary activities and accounts. Thus, any changes to BPA estimates cannot be used to affect any other budget categories which have their own legal dollar caps. Because BPA operates within existing legislative authority, BPA is not subject to a Budget Enforcement "pay-as-you-go" test regarding its revision of current-law funding estimates.

5/ Treasury Borrowing Authority to Finance Other Obligations represents the use of (positive), or building up of (negative), deferred borrowing. Deferred borrowing is created when Bonneville uses cash from revenues to liquidate capital obligations in lieu of Treasury borrowing. This creates the ability in future years to borrow money, when fiscally prudent, to liquidate revenue funded activities. The amount on this line, under the title "Treasury Borrowing Authority to Finance Other Obligations" represents the annual use or creation of deferred borrowing. OMB has requested that Bonneville show this deferred borrowing as a resource carried forward from year to year in the manner displayed here.

CURRENT SERVICES
(in millions of dollars)

CAPITAL TRANSFERS	2007 Pymts	2008 Pymts	2009 Pymts	2010 Pymts	2011 Pymts	2012 Pymts	2013 Pymts
		FISCAL YEAR					
Amortization:							
20 BPA Bonds	506	241	259	345	115	40	155
21 Reclamation Appropriations	0	0	0	0	1	0	0
22 BPA Appropriations	59	31	7	76	109	157	92
23 Corps Appropriations	58	136	10	3	192	96	0
24 **TOTAL CAPITAL TRANSFERS**	**623**	**408**	**276**	**424**	**417**	**293**	**247**
		STAFFING					
25 **FULL-TIME EQUIVALENT (FTE)**	**2,896**	**3,000**	**3,000**	**3,000**	**3,000**	**3,000**	**3,000**

The accompanying notes are an integral part of this table.

The cumulative amount of actual advance amortization payments as of the end of FY 2007 is $2,091 million.

PROGRAM & FINANCING SUMMARY

Current Services

(in millions of dollars)

Identification Code: 89-4045-0-3-271

		2007	2008	est. 2009	2010	2011	2012	2013
	Program by activities:							
	Operating expenses:							
0.01	Power Services	896	1,236	1,333	1,154	1,211	1,219	1,139
0.02	Residential Exchange	301	337	337	300	300	171	171
	Associated Project Costs:							
0.05	Bureau of Reclamation	67	75	78	80	81	84	84
0.06	Corps of Engineers	158	166	170	177	182	187	187
0.07	Colville Settlement	20	17	18	18	19	19	19
0.19	U.S. Fish & Wildlife Service	19	20	20	21	22	22	22
0.20	Planning Council	8	9	9	10	10	10	10
0.21	Fish & Wildlife	139	143	143	143	143	143	143
0.23	Transmission Services	286	301	315	322	330	336	343
0.24	Conservation & Energy Efficiency	62	66	66	69	69	74	74
0.25	Interest	395	332	345	372	391	411	444
0.26	Pension and Health Benefits 1/	21	18	31	31	31	32	32
0.91	**Total operating expenses 2/**	**2,372**	**2,720**	**2,865**	**2,697**	**2,789**	**2,708**	**2,668**
	Capital investment:							
1.01	Power Services	108	159	137	143	148	153	158
1.02	Transmission Services	141	242	294	278	370	419	320
1.03	Conservation & Energy Efficiency	7	42	42	40	40	45	45
1.04	Fish & Wildlife	35	36	36	36	36	36	36
1.05	Capital Equipment	21	31	51	55	27	27	28
1.06	Capitalized Bond Premiums	0	0	0	0	2	2	2
1.07	**Total Capital Investment 3/**	**312**	**510**	**560**	**552**	**623**	**682**	**589**
1.08	Misc. Accounting Adjustments	0						
2.01	Projects Funded in Advance	84	72	125	66	79	72	73
10.00	**Total obligations 4/**	**2,768**	**3,302**	**3,549**	**3,315**	**3,491**	**3,462**	**3,330**

The accompanying notes are an integral part of this table.

1/ See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

2/ Assumes expense obligations, not accrued expenses.
Power Services includes Fish & Wildlife, Residential Exchange, Planning Council, Conservation & Energy Efficiency and Associated Project Costs which have been shown separately for display purposes.

3/ Assumes capital obligations, not capital expenditures.

4/ This FY 2009 budget includes capital and expense estimates for PS based on forecasted FY 2007 Final Power Rate Proposal and associated outyear estimates for FYs 2010-2013. The TS capital and expense estimates are based on forecasted Transmission 2008 Rate Case estimates and associated outyear estimates for FYs 2010-2013.

For purposes of this table, this FY 2009 budget reflects, for FY 2007, actual third party financing expense only for PFIA.

Capital funding levels also reflect BPA’s Capital Planning Review Process and external factors such as the significant changes affecting West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2009 budget have been updated to reflect executive management decisions from BPA’s Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

Refer to 16 USC Chapters 12B, 12G, 12H, and BPA's other organic laws, including P.L. 100-371, Title III, Sec. 300, 102 Stat. 869, July 18, 1988 regarding BPA's ability to obligate funds.

Program and Financing (continued)
Current Services
(in millions of dollars)

	est.						
	2007	2008	2009	2010	2011	2012	2013
Financing:							
21.90 Unobligated balance available, start of year. 5/	0	47	31	20	12	3	0
24.40 Unobligated balance available, end of year.5/	47	31	20	12	3	0	0
25.00 Unobligated balance lapsing							
39.00 **Budget authority (gross)**	**3,182**	**3,318**	**3,561**	**3,323**	**3,500**	**3,465**	**3,329**
Budget Authority:							
61.00 Transfer to other accounts	74						
62.00 Transfer from other accounts	49						
66.10 Contract Authority							
67.10 Adjusted Permanent Authority: Authority to borrow from Treasury (indefinite) 6/	315	434	288	446	424	286	237
Spending authority from off-setting collections	3,321	3,293	3,549	3,316	3,492	3,472	3,339
69.47 Portion applied to debt reduction	(556)	(408)	(276)	(424)	(417)	(293)	(247)
69.90 **Spending authority from offsetting collections (adjusted)**	**2,387**	**2,884**	**3,273**	**2,892**	**3,076**	**3,179**	**3,092**
71.00 Total obligations	2,768	3,301	3,550	3,314	3,491	3,462	3,329
87.00 Outlays (gross)	2,782	3,335	3,572	3,346	3,509	3,468	3,329
Adjustments to budget authority and outlays:							
Deductions for offsetting collections:							
88.00 Federal funds	(40)	(90)	(90)	(90)	(90)	(90)	(90)
88.40 Non-Federal sources	(3,454)	(3,203)	(3,459)	(3,227)	(3,402)	(3,382)	(3,249)
88.90 Total, offsetting collections	(3,494)	(3,293)	(3,549)	(3,316)	(3,492)	(3,472)	(3,339)
89.00 **Budget authority (net)**	**(312)**	**26**	**12**	**22**	**8**	**(7)**	**(10)**
90.00 **Outlays (net) 7/**	**(508)**	**42**	**23**	**30**	**17**	**(4)**	**(10)**

The accompanying notes are an integral part of this table.

5/ Reflects estimated cost for radio spectrum fund.

6/ The Permanent Authority: Authority to borrow (indefinite) from Treasury amounts reflect both BPA's capital program financing needs and either the use of, or creation of, deferred borrowing. Deferred borrowing in created when, as a cash and debt management decision, BPA uses cash from revenues to liquidate capital obligations in lieu of borrowing from Treasury. This temporary use of cash on hand instead of borrowed funds creates the ability in future years to borrow money, when fiscally prudent. Technical Executive Branch budget display and tracking requirements have modified the way BPA shows this deferred borrowing as a resource carried forward from year-to-year. This amount must therefore be added to, or subtracted from, BPA's current year Treasury borrowing authority amount, making this number a combination of capital program financing needs and the annual use, or creation of deferred borrowing. The FY 1989 Energy and Water Development Appropriations Act (P.L. 100-371 of 7/19/88) clarified that BPA has authority to incur obligations in excess of Treasury borrowing authority and cash in the BPA Fund. The two amounts which comprise the net amount of line 67.10 above as follows:

	FISCAL YEAR						
Treasury Borrowing Authority:	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
to finance capital obligations	314	510	560	552	623	682	589
to finance other obligations	1	(76)	(272)	(106)	(199)	(396)	(352)
Adjusted Permanent Authority to Borrow	**315**	**434**	**288**	**446**	**424**	**286**	**237**

7/ Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that, along with actual market conditions, will impact revenues and expenses. Actual Net Outlays are volatile and are reported in SF-133. Estimated Net Outlays could change due to changing market conditions, streamflow variability, and continuing restructuring of the electric industry.

Revenues, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools, including upcoming rate adjustment mechanisms, a net revenue risk adjustment, debt service refinancing strategies and/or short-term financial tools to manage net revenues and cash. Some of these potential tools will reduce costs rather than generate revenue, causing the same Net Outlay result. Adjustments for depreciation and 4(h)(10)(C) credits of the NW Power Act are also assumed.

This budget has been prepared in accordance with the Budget Enforcement Act (BEA) of 1990. Under this Act all BPA budget estimates are treated as mandatory and are not subject to the discretionary caps included in the BEA. These estimates support activities which are legally separate from discretionary activities and accounts. Thus, any changes to BPA estimates cannot be used to affect any other budget categories which have their own legal dollar caps. Because BPA operates within existing legislative authority, BPA is not subject to a Budget Enforcement "pay-as-you-go" test regarding its revision of current-law funding estimates.

BONNEVILLE POWER ADMINISTRATION
BPA STATUS of TREASURY BORROWING
CURRENT SERVICES
(in millions of dollars)

BP-4A

	Fiscal Year 2007				2008			
	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing
Start-of-Year: Total	1,624	1,624	2,717	2,440	1,430	1,430	2,523	2,240
Plus: Annual Increase								
Cum.-Annual Treasury Borrowing	312	312	312		510	510	510	
Treasury Borrowing (Cash)				306				510
Less:								
BPA Bond Amortization	506	506	506	506	241	241	241	241
Net Increase/(Decrease):	(194)	(194)	(194)	(200)	269	269	269	269
Cum.-End-of-Year: Total	1,430	1,430	2,523	2,240	1,699	1,699	2,792	2,509
Total Remaining Treasury Borrowing Amount				2,210				1,941
Total Legislated Treasury Borrowing Amount				4,450				4,450

The accompanying notes are an integral part of this table.
In any given year, BPA may issue less debt than forecast depending on net revenues, Treasury interests rates, and other cash management factors. In such cases, BPA accumulates a deferred borrowing balance that it accesses as necessary in the future.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2009 budget have been updated to reflect executive management decisions from BPA's Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

BPA reserve financing of $15 million annually is assumed as part of TS capital-PFIA for FYs 2008-2009.

The cumulative amount of actual advance amortization payments as of the end of FY 2007 is $2,091 million.

BONNEVILLE POWER ADMINISTRATION
BPA STATUS of TREASURY BORROWING
CURRENT SERVICES
(in millions of dollars)

BP-4B

	Fiscal Year 2009				Fiscal Year 2010			
	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing
Start-of-Year: Total	1,699	1,699	2,792	2,509	2,000	2,000	3,093	2,810
Plus: Annual Increase								
Cum.-Annual Treasury Borrowing	560	560	560		552	552	552	
Treasury Borrowing (Cash)				560				552
Less:								
Total BPA Bond Amortization	259	259	259	259	345	345	345	345
Net Increase/(Decrease):								
Total	301	301	301	301	207	207	207	207
Cum.-End-of-Year: Total	2,000	2,000	3,093	2,810	2,207	2,207	3,300	3,017
Total Remaining Treasury Borrowing Amount				1,640				1,433
Total Legislated Treasury Borrowing Amount				4,450				4,450

The accompanying notes are an integral part of this table.
In any given year, BPA may issue less debt than forecast depending on net revenues, Treasury interests rates, and other cash management factors. In such cases, BPA accumulates a deferred borrowing balance that it accesses as necessary in the future.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2009 budget have been updated to reflect executive management decisions from BPA's Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

BPA reserve financing of $15 million annually is assumed as part of TS capital-PFIA for FYs 2008-2009.

BONNEVILLE POWER ADMINISTRATION
BPA STATUS of TREASURY BORROWING
CURRENT SERVICES
(in millions of dollars)

BP-4C

	Fiscal Year 2011				Fiscal Year 2012			
	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing
Start-of-Year: Total	2,207	2,207	3,300	3,017	2,714	2,714	3,807	3,524
Plus: Annual Increase								
Cum.-Annual Treasury Borrowing	622	622	622		681	681	681	
Treasury Borrowing (Cash)				622				681
Less:								
Total BPA Bond Amortization	115	115	115	115	40	40	40	40
Net Increase/(Decrease):								
Total	507	507	507	507	641	641	641	641
Cum.-End-of-Year: Total	2,714	2,714	3,807	3,524	3,355	3,355	4,448	4,165
Total Remaining Treasury Borrowing Amount				926				285
Total Legislated Treasury Borrowing Amount				4,450				4,450

The accompanying notes are an integral part of this table.

In any given year, BPA may issue less debt than forecast depending on net revenues, Treasury interests rates, and other cash management factors. In such cases, BPA accumulates a deferred borrowing balance that it accesses as necessary in the future.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2009 budget have been updated to reflect executive management decisions from BPA's Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

BPA reserve financing of $15 million annually is assumed as part of TS capital-PFIA for FYs 2008-2009.

BONNEVILLE POWER ADMINISTRATION
BPA STATUS of TREASURY BORROWING
CURRENT SERVICES
(in millions of dollars)

BP-4D

	Fiscal Year 2013			
	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing
Start-of-Year: Total	3,355	3,355	4,448	4,165
Plus: Annual Increase				
Cum.-Annual Treasury Borrowing	588	588	588	
Treasury Borrowing (Cash)				588
Less:				
Total BPA Bond Amortization	155	155	155	155
Net Increase/(Decrease):				
Total	433	433	433	433
Cum.-End-of-Year: Total	3,788	3,788	4,881	4,598
Total Remaining Treasury Borrowing Amount				(148)
Total Legislated Treasury Borrowing Amount				4,450

The accompanying notes are an integral part of this table.

In any given year, BPA may issue less debt than forecast depending on net revenues, Treasury interests rates, and other cash management factors. In such cases, BPA accumulates a deferred borrowing balance that it accesses as necessary in the future.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2009 budget have been updated to reflect executive management decisions from BPA's Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

BPA reserve financing of $15 million annually is assumed as part of TS capital-PFIA for FYs 2008-2009.

BONNEVILLE POWER ADMINISTRATION
POTENTIAL THIRD PARTY FINANCING TRANSPARENCY

(in millions of dollars)

BP-5

		Fiscal Year						
Transmission Services - Capital		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Main Grid	Requirements	5	32	70	87	204	260	163
Area & Customer Services		3	39	32	7	12	7	28
Upgrades & Additions		51	71	65	60	70	70	40
System Replacements		82	101	126	124	84	83	89
Projects Funded in Advance		107	72	125	66	79	72	73
Total, Transmission Services - Capital		**248**	**315**	**418**	**344**	**449**	**492**	**393**
Federal and Non-Federal Funding								
Projects Funded in Advance	Sources	107	72	125	66	79	72	73
Treasury Borrowing Authority		141	243	293	278	370	420	320
Scenario								
Third Party Financing	Scenario	5	110	157	122	194	240	174
Alternate Treasury Borrowing Authority		136	133	136	156	176	180	146

The accompanying notes are an integral part of this table.

The table above shows both the potential use of Treasury borrowing authority for transmission capital projects based on this FY 2009 budget and the use adjusted for potential third-party financing to fund appropriate capital expenditures when feasible in lieu of Treasury borrowing. Estimates included in this FY 2009 budget are uncertain and may change due to revised capital investment plans, changing economic conditions, and an evolving financial market environment. The estimates of third-party financing included in the table show a reduction in the use of Treasury borrowing and do not reflect the actual notional third party financing commitment BPA may enter into in that particular year. The difference of reduction in use of Treasury borrowing and the actual notional third party financing commitment is primarily due to the difference in the timing of financing transactions between Treasury and third-party financing for capital projects with multi-year construction schedules.

TREASURY PAYMENTS

(in millions of dollars)

		FISCAL YEAR						
		2007	2008	2009	2010	2011	2012	2013
A.	**INTEREST ON BONDS & APPROPRIATIONS**							
	Bonneville Bond Interest							
1	Bonneville Bond Interest (net)	108	67	89	113	130	167	209
2	AFUDC [1/]	21	17	18	19	22	24	20
	Appropriations Interest							
3	Bonneville	45	41	39	38	33	25	13
4	Corps of Engineers [2/]	162	164	158	161	169	160	162
5	Lower Snake River	16	16	16	16	16	16	16
6	Bureau of Reclamation [3/]	43	43	43	43	43	43	43
7	**Total Bond and Approp. Interest**	**395**	**348**	**363**	**390**	**413**	**435**	**463**
B.	**ASSOCIATED PROJECT COST**							
8	Bureau of Reclamation Irrigation Assistance	1	0	3	7	0	31	29
9	Bureau of Rec. O & M [4/]	2	0	0	0	0	0	0
10	Corps of Eng. O & M [4/]	3	0	0	0	0	0	0
11	L. Snake River Comp. Plan O & M [4/]	0	0	0	0	0	0	0
12	**Total Assoc. Project Costs**	**6**	**0**	**3**	**7**	**0**	**31**	**29**
C.	**CAPITAL TRANSFERS**							
	Amortization							
13	Bonneville Bonds	506	241	259	345	115	40	155
14	Bureau of Reclamation Appropriations	0	0	0	0	1	0	0
15	Corps of Engineers Appropriations	58	136	10	3	192	96	0
16	Lower Snake River Comp. Plan	0	0	0	0	0	0	0
17	Bonneville Appropriations	59	31	7	76	109	157	92
	Total Capital Transfers	**623**	**408**	**276**	**424**	**417**	**293**	**247**
D.	**OTHER PAYMENTS**							
18	Unfunded CSRS Liability [5/]	21	18	31	31	31	32	32
21	**TOTAL TREASURY PAYMENTS [6/]**	**1,045**	**774**	**673**	**852**	**861**	**791**	**771**

The accompanying notes are an integral part of this table.

1/ This interest cost is capitalized and included in BPA's Transmission System Development, System Replacments, and Associated Projects Capital programs. AFUDC is financed through the sale of bonds.

2/ Includes interest on construction funding for Corp of Engineers (Corps) fish bypass facilities at Corps dams in the Columbia River Basin, including Lower Monumental, Ice Harbor, and The Dalles.

3/ Includes payments paid by Reclamation to Treasury on behalf of Bonneville.

4/ Costs for power O&M is funded directly by Bonneville as follows (in millions)

FISCAL YEAR	2007	2008	2009	2010	2011	2012	2013
Bureau of Reclamation	67	75	78	80	81	84	84
Corps of Engineers	158	166	170	177	182	187	187
Subtotal Bureau and Corps	225	241	248	257	263	271	271
Lower Snake River Comp. Plan	19	20	20	21	22	22	22
Total	244	261	268	278	285	293	293

5/ See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

6/ Does not include Treasury bond premiums on refinanced Treasury bonds.

BPA Amortization/Capital Transfers for FY 2007 includes $5 million payment to Treasury for reimbursement of judgment funds, consistent with the Enron settlement agreement in 2003.

OBJECT CLASSIFICATION STATEMENT
(in millions of dollars) 1/

IDENTIFICATION CODE: 89-4045-0-3-271
DIRECT OBLIGATIONS

ESTIMATES

		2007	2008	2009
11.1	Full-time permanent	167	191	205
11.3	Other than full-time permanent	42	42	45
11.5	Other personnel compensation	19	12	13
11.9	**Total personnel compensation**	228	245	**263**
12.1	Civilian personnel benefits	57	60	64
13.0	Benefits for former personnel	21	30	32
21.0	Travel and transportation of persons	16	13	14
22.0	Transportation of things	4	1	1
23.1	Rental payments to GSA	1		
23.2	Rents, other	48	26	28
23.3	Communication, utilities & misc. charges	8	7	8
25.1	Consulting Services	273	247	266
25.2	Other Services	1,300	1,731	1,865
25.3	Purchases from Government Accounts			
25.4	O&M of Facilities			
25.5	R & D Contracts	11	14	13
26.0	Supplies and materials	124	64	69
31.0	Equipment			
32.0	Lands and structures	31	17	18
41.0	Grants, subsidies, contributions	60	7	7
43.0	Interest and dividends	586	839	902
99.0	**Total obligations**	**2,768**	**3,301**	**3,550**

Includes object classifications developed from updated GL accounting codes consistent with implementation of BPA's business enterprise system of accounts. The object classifications are subject to change as BPA's GL accounting codes continue to evolve to more effectively meet management information needs, and meet FERC and Federal reporting requirements.

Estimate of Proprietary Receipts
(in millions of dollars)

	Fiscal Year						
	2007	2008	2009	2010	2011	2012	2013
Reclamation Interest	43	43	43	43	43	43	43
Reclamation Amortization	0	0	0	0	1	0	0
Reclamation O&M	1	0	0	0	0	0	0
Reclamation Irrig. Assist.	1	0	3	7	0	31	29
Revenues Collected by Reclamation Distributed in Treasury Account (credit)	-8	-7	-7	-7	-7	-7	-7
Colville Settlement (credit)	-5	-5	-5	-5	-5	-5	-5
Total 1/ Reclamation Fund	**32**	**31**	**34**	**38**	**32**	**62**	**60**
Corps O&M	3						
CSRS	21	18	31	31	31	32	31
Total 2/ Repayments on misc.costs	**24**	**18**	**31**	**31**	**31**	**32**	**31**

1/ Includes amortization of appropriations and irrigation assistance, and interest costs for Reclamation. The cost of power O&M for Reclamation is no longer included in Proprietary Receipts due to Direct Funding by Bonneville. Represents transfer to Account #895000.26

2/ The costs of power O&M for the Corps and Lower Snake Comp. Plan are no longer included in Proprietary Receipts due to Direct Funding by Bonneville. Represents transfers to Account #892889, Repayments on misc. recoverable costs, not otherwise classified. Costs for power O&M is funded directly by Bonneville as follows (in millions)

	2007	2008	2009	2010	2011	2012	2013
Bureau of Reclamation	67	75	78	80	81	84	84
Corps of Engineers	158	166	170	177	182	187	187
Lower Snake River Comp. Plan	19	20	20	21	22	22	22

See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

BONNEVILLE POWER ADMINISTRATION

FISH AND WILDLIFE COSTS [1/]

COST ELEMENT	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
CAPITAL INVESTMENTS [2/]										
BPA FISH AND WILDLIFE	22.0	14.7	13.9	16.5	6.1	11.6	8.5	12.2	36.3	36.2
ASSOCIATED PROJECTS (FEDERAL HYDRO)	-	14.1	47.0	6.2	8.8	68.4	75.9	53.8	360.0	60.4
BPA DIRECT FISH AND WILDLIFE PROGRAM	104.9	108.2	108.2	101.1	137.1	140.7	137.9	135.8	137.9	139.5
SUPPLEMENTAL MITIGATION PROGRAM EXPENSES [3/]				2.9	7.1	6.5	7.8	7.5	0.0	0.0
REIMBURSABLE/DIRECT-FUNDED PROJECTS [4/]										
O & M LOWER SNAKE RIVER HATCHERIES	11.4	13.0	12.4	12.7	14.9	15.1	17.3	17.2	20.1	19.3
O & M CORPS OF ENGINEERS	18.5	19.9	19.7	23.1	28.2	30.3	32.3	32.5	31.8	32.9
O & M BUREAU OF RECLAMATION	2.7	2.6	1.8	3.0	3.8	3.1	3.9	3.9	4.5	3.9
OTHER (NW POWER AND CONSERVATION COUNCIL)	3.7	3.4	3.7	3.7	4.0	4.0	3.7	4.3	4.3	4.2
SUBTOTAL (REIMB/DIRECT-FUNDED)	36.4	38.9	37.6	42.5	50.9	52.6	57.2	57.9	60.7	60.3
TOTAL OPERATING EXPENSES	**141.3**	**147.1**	**145.8**	**146.5**	**195.1**	**199.8**	**202.9**	**193.7**	**198.6**	**199.8**
PROGRAM RELATED FIXED EXPENSES [5/]										
INTEREST EXPENSE	48.9	49.4	48.4	49.1	48.5	49.9	53.3	56.4	53.4	76.0
AMORTIZATION EXPENSE	14.1	15.3	16.1	16.8	17.2	17.4	17.5	17.4	17.4	22.9
DEPRECIATION EXPENSE	11.1	11.4	11.8	12.3	12.5	13.2	14.6	15.9	16.7	14.0
TOTAL FIXED EXPENSES	**74.1**	**76.1**	**76.3**	**78.2**	**78.2**	**80.5**	**85.4**	**89.7**	**87.5**	**112.9**
GRAND TOTAL PROGRAM EXPENSES	**215.4**	**223.2**	**222.1**	**224.7**	**273.3**	**280.3**	**288.3**	**283.4**	**286.1**	**312.7**
FOREGONE REVENUES AND POWER PURCHASES										
FOREGONE REVENUES	116.5	197.8	193.1	115.9	12.6	79.2	21.7	182.1	397.4	282.6
BPA POWER PURCH. FOR FISH ENHANCEMENT	5.4	47.6	64.8	1,389.6	147.8	171.1	191.0	110.8	168.2	120.7
TOTAL FOREGONE REVENUES AND POWER PURCHASES	**121.9**	**245.4**	**257.9**	**1,505.5**	**160.4**	**250.3**	**212.7**	**292.9**	**565.6**	**403.3**
TOTAL PROGRAM EXPENSES, FOREGONE REVENUES, & POWER PURCHASES	**337.3**	**468.6**	**480.0**	**1,730.2**	**433.7**	**530.6**	**501.0**	**576.3**	**851.7**	**716.0**
CREDITS										
4(h)(10)(C) credits earned	(35.7)	(46.0)	(50.4)	(336.6)	(66.4)	(73.6)	(77.0)	(57.7)	(76.4)	(66.1)
FISH COST CONTINGENCY FUND [6/]	-	-	-	(246.5)	-	(78.7)	-	-	-	-
TOTAL CREDITS	**(35.7)**	**(46.0)**	**(50.4)**	**(583.1)**	**(66.4)**	**(152.3)**	**(77.0)**	**(57.7)**	**(76.4)**	**(66.1)**

1/ For purposes of this presentation, this financial information has been made publicly available by BPA in February 2008 and is consistent with the financial system of record used in preparation of the audited financial statements for the respective period reported.

2/ Capital Investments include both BPA's direct Fish and Wildlife Program capital investments, funded by BPA's Treasury borrowing, and "Associated Projects", which include capital investments at the Corps and Reclamation projects, funded by appropriations and repaid by BPA. The negative amount in FY 1997 reflects a decision to reverse "plant-in-service" investment that was never actually placed into service. The annual expenses associated with these investments are included in "Program-Related Fixed Expenses", below.

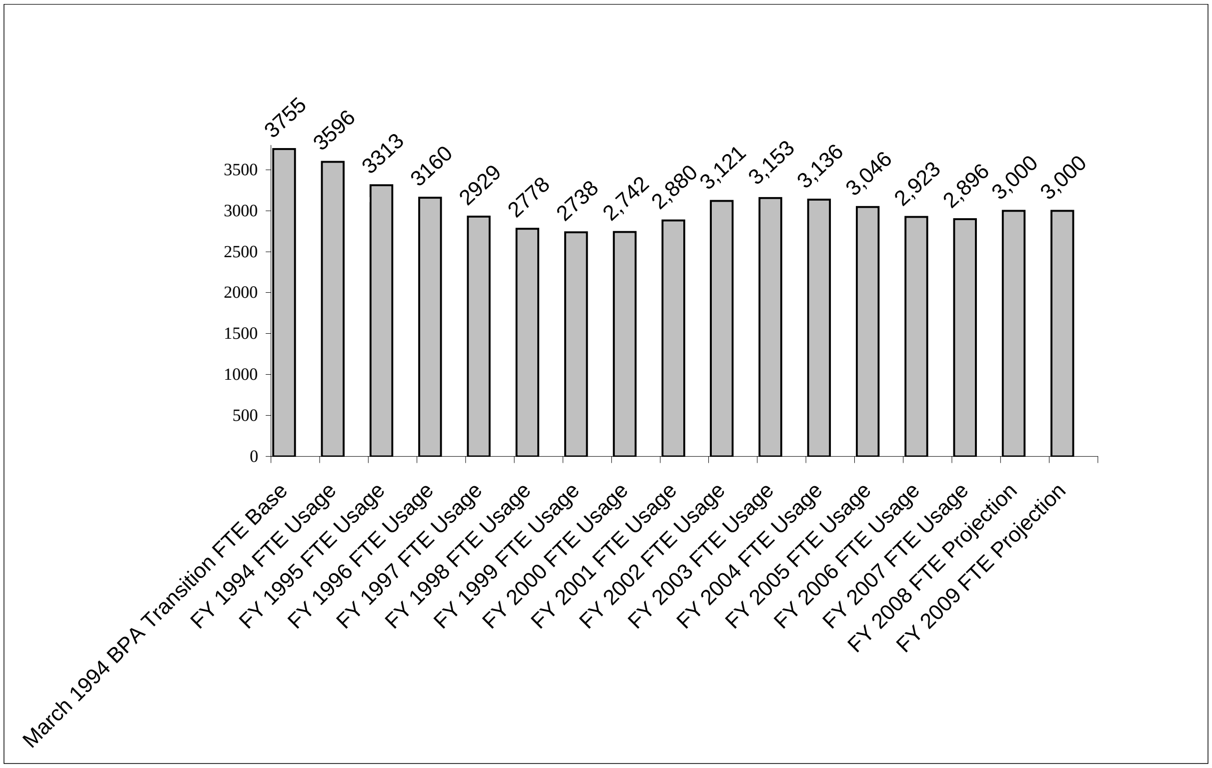
3/ Supplemental Mitigation Program Expenses includes High Priority and Action Plan Expenses and other supplemental programs.

4/ Reimbursable/Direct-Funded Projects includes the portion of costs BPA pays to or on behalf of other entities that is determined to be for fish and wildlife purposes.

5/ Fixed Expenses include depreciation and interest on investment on the Corps projects, and amortization and interest on the investments associated with BPA's direct Fish and Wildlife Program.

6/ The Fish Contingency Fund was exhausted in 2003

BONNEVILLE FTE
(revised January 2008)



BPA has utilized the following number of Voluntary Separation Incentives (VSIs): 190 in FY 1994, 240 in FY 1995, 137 in FY 1996, 135 in FY 1997, 121 in FY 1998, 81 in FY 1999, 43 in FY 2000, 12 in FY 2001, 0 in FY 2002, 80 in FY 2003, 0 in FY 2004, 98 in 2005, 35 in FY 2006, and 37 in FY 2007.

BPA continues to assume various authorities, including the use of voluntary separation incentives (VSI) and voluntary early retirement authority (VERA) to help achieve BPA planning levels.

Actual FTE data is consistent with DOE personnel reports.

FTE outyear data are estimates and may change.

Commercial Spectrum Enhancement Act

On December 23, 2004, President Bush signed into law the Commercial Spectrum Enhancement Act (CSEA, title II of P.L. 108-494) that created the Spectrum Relocation Fund (SRF) to provide a centralized and streamlined funding mechanism through which Federal agencies can recover the costs associated with relocating their radio communications systems from certain spectrum bands, which were authorized to be auctioned for commercial purposes. The CSEA appropriated such sums as are required for relocation costs, which are financed by auction proceeds.

On September 18, 2006, the Federal Communications Commission (FCC) concluded an auction of licenses for Advanced Wireless Services (AWS), on radio spectrum in the 1710 megahertz (MHz) to 1755 MHz band that is presently used by Federal agencies, which was paired with the 2110 MHz to 2155 MHz band in the auction. The 1710 MHz to 1755 MHz band of spectrum was relocated to AWS under the provisions of the CSEA, including the use of the SFR to facilitate relocation of Federal communications systems, while the 2110 MHz to 2155 MHz band was reallocated to AWS by the FCC and does not require relocation of Federal systems. The AWS auction raised $13.7 billion in net winning bids, and will facilitate the provision of innovative new wireless services to the commercial market.

In FY 2007, in accordance with Section 204 of the CSEA, the transfer of funds from the SRF to agencies for relocation activities will proceed after the Director of OMB, in consultation with the NTIA, has determined the cost and timelines of relocation the activities. In addition, the CSEA required that transfers may not be made until 30 days after the Director of OMB has notified the Congress of how the SRF will be used to pay relocation costs and the timeline for such relocation activities. Congress will be provided annual updates on the progress of all spectrum relocation activities following the initial transfer of funds.

The total estimate for relocation or modification costs for DOE's radio communications systems in the 1710-1755 MHz band for FY 2007 is $176.8 million. This total represents estimated costs to relocate 36 systems and 168 frequency assignments to support the systems being relocated as detailed below. The estimated unit cost for a particular fixed microwave system is dependent on such variables as the number of radios and towers that need replacement or modification, and the time of year relocation work occurs.

DOE estimates that the timeline for relocating its electric grid command and control system is between 2 and 6 years from the date of the agency's receipt of relocation funds. The table below provides cost estimates for each system that will be relocated. The first annual report on Spectrum Relocation will be submitted to Congress early Spring of FY 2008.

DOE PROGRAM	COST ($ in millions)	TIME (in months)	NUMBER OF SYSTEMS
NNSA	$ 10.9	36	15
SWPA	$ 8.1	24	1
WAPA	$ 108.2	36	6
BPA	$ 48.7	72	14
OCIO	$ 1.0	72	Administration
TOTAL	**$ 176.8**	**N/A**	**36**

GENERAL PROVISIONS

SEC. 301. CONTRACT COMPETITION.
(a) None of the funds in this or any other appropriations Act for fiscal year **[**2008 **]***2009* or any previous fiscal year may be used to make payments for a noncompetitive management and operating contract, or a contract for environmental remediation or waste management in excess of $100,000,000 in annual funding at a current or former management and operating contract site or facility, or award a significant extension or expansion to an existing management and operating contract, or other contract covered by this section, unless such contract is awarded using competitive procedures or the Secretary of Energy grants, on a case-by-case basis, a waiver to allow for such a deviation. The Secretary may not delegate the authority to grant such a waiver.
(b) *In this section:*
(*1*) *The term "noncompetitive management and operating contract" means a contract that was awarded more than 50 years ago without competition for the management and operation of Ames Laboratory, Argonne National Laboratory, Lawrence Berkeley National Laboratory, Livermore National Laboratory, and Los Alamos National Laboratory.*
(*2*) The term "competitive procedures" has the meaning provided in section 4 of the Office of Federal Procurement Policy Act (41 U.S.C. 403) and includes procedures described in section 303 of the Federal Property and Administrative Services Act of 1949 (41 U.S.C. 253) other than a procedure that solicits a proposal from only one source.
(*c*) *For all management and operating contracts other than those listed in subsection (b)(1), none of the funds appropriated by this Act may be used to award a management and operating contract, unless such contract is awarded using competitive procedures or the Secretary of Energy grants, on a case-by-case basis, a waiver to allow for such a deviation. The Secretary may not delegate the authority to grant such a waiver. At least 60 days before a contract award for which the Secretary intends to grant such a waiver, the Secretary shall submit to the Committees on Appropriations of the House of Representatives and the Senate a report notifying the Committees of the waiver and setting forth, in specificity, the substantive reasons why the Secretary believes the requirement for competition should be waived for this particular award.*
[(c) Within 30 days of formally notifying an incumbent contractor that the Secretary intends to grant such a waiver, the Secretary shall submit to the Subcommittees on Energy and Water Development of the Committees on Appropriations of the House of Representatives and the Senate a report notifying the Subcommittees of the waiver and setting forth, in specificity, the substantive reasons why the Secretary believes the requirement for competition should be waived for this particular award.**]**
SEC. 302. UNFUNDED REQUESTS FOR PROPOSALS. None of the funds appropriated by this Act may be used to prepare or initiate Requests For Proposals (RFPs) for a program if the program has not been funded by Congress.
SEC. 303. WORKFORCE RESTRUCTURING. None of the funds appropriated by this Act may be used to—
(1) develop or implement a workforce restructuring plan that covers employees of the Department of Energy; or

(2) provide enhanced severance payments or other benefits for employees of the Department of Energy, under section 3161 of the National Defense Authorization Act for Fiscal Year 1993 (Public Law 102-484; 42 U.S.C. 7274h).

SEC. 304. SECTION 3161 ASSISTANCE. None of the funds appropriated by this Act may be used to augment the funds made available for obligation by this Act for severance payments and other benefits and community assistance grants under section 3161 of the National Defense Authorization Act for Fiscal Year 1993 (Public Law 102-484; 42 U.S.C. 7274h) unless the Department of Energy submits a reprogramming **[**request**]** *notification* to the appropriate congressional committees.

SEC. 305. UNEXPENDED BALANCES. The unexpended balances of prior appropriations provided for activities in this Act may be available to the same appropriation accounts for such activities established pursuant to this title. Available balances may be merged with funds in the applicable established accounts and thereafter may be accounted for as one fund for the same time period as originally enacted.

SEC. 306. BONNEVILLE POWER AUTHORITY SERVICE TERRITORY. None of the funds in this or any other Act for the Administrator of the Bonneville Power Administration may be used to enter into any agreement to perform energy efficiency services outside the legally defined Bonneville service territory, with the exception of services provided internationally, including services provided on a reimbursable basis, unless the Administrator certifies in advance that such services are not available from private sector businesses.

SEC. 307. USER FACILITIES. When the Department of Energy makes a user facility available to universities or other potential users, or seeks input from universities or other potential users regarding significant characteristics or equipment in a user facility or a proposed user facility, the Department shall ensure broad public notice of such availability or such need for input to universities and other potential users. When the Department of Energy considers the participation of a university or other potential user as a formal partner in the establishment or operation of a user facility, the Department shall employ full and open competition in selecting such a partner. For purposes of this section, the term "user facility" includes, but is not limited to: (1) a user facility as described in section 2203(a)(2) of the Energy Policy Act of 1992 (42 U.S.C. 13503(a)(2)); (2) a National Nuclear Security Administration Defense Programs Technology Deployment Center/User Facility; and (3) any other Departmental facility designated by the Department as a user facility.

SEC. 308. INTELLIGENCE ACTIVITIES. Funds appropriated by this or any other Act, or made available by the transfer of funds in this Act, for intelligence activities are deemed to be specifically authorized by the Congress for purposes of section 504 of the National Security Act of 1947 (50 U.S.C. 414) during fiscal year **[**2008 **]***2009* until the enactment of the Intelligence Authorization Act for fiscal year **[**2008 **]***2009*.

[SEC. 309. LABORATORY DIRECTED RESEARCH AND DEVELOPMENT. Of the funds made available by the Department of Energy for activities at government-owned, contractor-operator operated laboratories funded in this Act or subsequent Energy and Water Development Appropriations Acts, the Secretary may authorize a specific amount, not to exceed 8 percent of such funds, to be used by such laboratories for laboratory-directed research and development: *Provided*, That the Secretary may also authorize a specific amount not to exceed 4 percent of such funds, to be used by the plant manager of a covered nuclear weapons production plant or the manager of the Nevada Site Office for plant or site-directed research and development: *Provided further*, That notwithstanding Department of Energy order 413.2A, dated January 8, 2001, beginning in fiscal year 2006 and thereafter, all DOE laboratories may be eligible for laboratory directed research and development funding.**]**

[SEC. 310. YIELD RATE. For fiscal year 2008, except as otherwise provided by law in effect as of the date of this Act or unless a rate is specifically set by an Act of Congress thereafter, the Administrators of the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration, shall use the "yield" rate in computing interest during construction and interest on the unpaid balance of the costs of Federal power facilities. The yield rate shall be defined as the average yield during the preceding fiscal year on interest-bearing marketable securities of the United States which, at the time the computation is made, have terms of 15 years or more remaining to maturity.**]**

[SEC. 311. USE PERMIT. The Use Permit granted to the contractor for activities conducted at the Pacific Northwest National Laboratory by Agreement DE-GM05-00RL01831 between the Department of Energy and the contractor shall continue in effect during the term of the existing Operating Contract and the extensions or renewals thereof and shall be incorporated into any future management and operating contract for the Pacific Northwest National Laboratory and such Use Permit may not be waived, modified or terminated unless agreed to by both contractor and the Department of Energy.**]**

[SEC. 312. (a) ACROSS-THE-BOARD RESCISSIONS.—There is hereby rescinded—

(1) from discretionary accounts in this title that contain congressionally directed projects, an amount equal to 1.6 percent of the budget authority provided for fiscal year 2008 for such projects; and

(2) from all discretionary accounts in this title, an amount equal to 0.91 percent of the other budget authority provided for fiscal year 2008.

(b) DEFINITIONS.—For purposes of this section: (1) The term "congressionally directed project" means a congressional earmark or congressionally directed spending item specified in the list of such earmarks and items for this division that is included in the explanatory statement described in section 4 (in the matter preceding division A of this consolidated Act).

(2) The term "other budget authority" means an amount equal to all discretionary budget authority, less the amount provided for congressionally directed projects.

(c) PROPORTIONATE APPLICATION TO OTHER PROGRAMS, PROJECTS, AND ACTIVITIES.—Any rescission made by subsection (a)(2) shall be applied proportionately—

(1) to each discretionary account; and

(2) within each such account, to each program, project, and activity (with programs, projects, and activities as delineated in the appropriation Act or accompanying reports for the relevant fiscal year covering such account).

(d) REPORT.—Within 30 days after the date of the enactment of this section, the Director of the Secretary of Energy shall submit to the Committees on Appropriations of the House of Representatives and the Senate a report specifying the account and amount of each rescission made pursuant to this section.**]**

SEC. *309. Section 312 of the Energy and Water Development Appropriations Act, 2004 (Pub. L. 108-137), is amended as follows: (1) In the first sentence by inserting between "the material" and "in the concrete silos", the words "formerly stored", by inserting before the period: "when such material is disposed at an Nuclear Regulatory Commission-regulated or Agreement State-regulated facility"; and (2) In the second sentence, striking "for the purpose" and everything that follows, and inserting; "after the material has been disposed at an NRC-regulated or Agreement materials being disposed as NRC-regulated or Agreement State-regulated facilities and shall not preclude the materials from otherwise being disposed at facilities operated by the Department of Energy so long as the materials meet the disposal facility's waste acceptance criteria." Not to exceed 5 per centum of any appropriation made available for Department of Energy activities funded in this Act or subsequent Energy and Water Development Appropriations Acts, not to exceed $5,000,000, may hereafter be transferred between such appropriations, but no such appropriation, except as otherwise provided, shall be increased or decreased by more than 5 per centum by any such transfers, and any such proposed transfers: Provided, That 15 days in advance of such transfer, notice shall be submitted to the Committees on Appropriations of the House and Senate.*
SEC. *310. Not to exceed 5 per centum of any appropriation made available for Department of Energy activities funded in this Act or subsequent Energy and Water Development Appropriations Acts may be transferred between such appropriations, but no such appropriation, except as otherwise provided, shall be increased or decreased by more than 5 per centum by any such transfers, and notification of such transfers shall be submitted promptly to the Committees on Appropriations of the House and Senate.*
SEC. *311. Section 311 of the Energy and Water Development Appropriations Act, 2008 is repealed. (Energy and Water Development and Related Agencies Appropriations Act, 2008.)*