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Fact Sheet for the Chairman, Subcommittee on Water, Power and Offshore Energy Resources, Committee on Interior and Insular Affairs, House of Representatives

October 1989

FEDERAL ELECTRIC POWER

Information Concerning the Colorado River Storage Project

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GAO

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Resources, Community, and
Economic Development Division

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October 3, 1989

The Honorable George Miller
Chairman, Subcommittee on
Water, Power and Offshore
Energy Resources
Committee on Interior and
Insular Affairs
House of Representatives

Dear Mr. Chairman:

In your October 6, 1988, letter and in subsequent discussions with your staff, you asked us for information to assist the Subcommittee's consideration of legislation to authorize continued construction of the Colorado River Storage Project (CRSP). Specifically, you asked for information concerning CRSP investment costs and repayments, revenues from power sales, power asset values, wholesale power rates (federal and nonfederal), and the modification of the planned Diamond Fork Power System of the Bonneville Unit so that it could provide commercial power. In addition, as agreed, we will report to you separately on the extent to which federal investment costs for federal power projects, and CRSP specifically, will be recovered.

BACKGROUND

CRSP is a comprehensive federal water project designed to develop the water resources of the Upper Colorado River Basin. This basin is located in Arizona, Colorado, New Mexico, Utah, and Wyoming. CRSP was authorized in 1956 by Public Law 84-485 (43 U.S.C. 620-620o).

CRSP's four multipurpose water storage units equalize the erratic flows of the Colorado River and its main tributaries. In addition, CRSP's 21 participating projects are designed to deliver water in upper basin states to serve farmers, municipalities, and industries. CRSP also provides flood control, recreation opportunities, and fish and wildlife enhancement activities, and produces electric power at its hydropower plants.

The largest of the participating projects is the Central Utah Project, which, as currently designed, could eventually include power-generating facilities known as the Bonneville Unit's Diamond Fork Power System. If constructed, Diamond Fork could include at least one power plant to supply electric power for project-pumping purposes and might also include additional power plants to provide commercial power. The Department of the Interior noted that a May 1988 draft plan for the Central Utah Project proposes to eliminate the Diamond Fork Power System from the project plans.

The federal government has been funding construction for CRSP, a portion of which is reimbursed by those who receive benefits from the project. The Department of the Interior's Bureau of Reclamation is responsible for project design, construction, and operation. The Department of Energy's Western Area Power Administration markets the electric power produced at CRSP power plants.

RESULTS IN BRIEF

Information we obtained primarily from the Western Area Power Administration and the Bureau of Reclamation shows the following:

-- As of September 30, 1987, investment costs in CRSP were about $2.5 billion, of which $1.8 billion will be reimbursed to the federal government. About $630 million of the reimbursable investment costs had been repaid. On the basis of current construction plans, the federal government's total reimbursable investment costs are expected to be about $3.9 billion.[1]

-- Most CRSP revenues are and will be derived from power customers (80.6 percent). Municipal and industrial water customers, along with irrigators, will contribute most of the remaining revenues. These revenues are used to pay operating costs, interest, and the reimbursable investment costs. Power revenues averaged about $106 million annually between 1980 and 1987.

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[1]The dollar amounts in this report are presented as sums of the actual expenses incurred when investment costs are reported, and as current dollar estimates of project costs as of the date specified for construction costs not yet incurred.

-- The book value of CRSP's power assets was $741.8 million, according to Western's financial statements as of September 30, 1987.

-- CRSP's composite wholesale electric power rates have ranged from 6.15 to 9.92 mills per kilowatt-hour from 1980 to March 1989.[2] Composite rates for power produced by federal projects nationwide in 1987 ranged from 6.81 to 39.63 mills per kilowatt-hour. The wholesale composite rates of 11 nonfederal utilities located in Western's marketing area ranged from 27.98 to 76.07 mills per kilowatt-hour in 1987.

-- As currently designed, the proposed Bonneville Unit with its Diamond Fork Power System would cost about $1.91 billion and provide about 18 megawatts of power for project-pumping purposes. To pay for the costs of this system, CRSP's wholesale electric power rates would need to be increased from the current rate of 9.92 to 11.08 mills per kilowatt-hour, according to a 1988 estimate. At your request, we estimated the effect an alternative system design could have on CRSP electric power rates and revenues. The alternative we considered would add about 60-megawatt of commercial power to the system and increase costs to $1.957 billion. This system design was based on Bureau of Reclamation data and is similar to alternatives that have been considered in recent years.

   According to our analysis, the CRSP rate would be between 10.66 and 11.34 mills per kilowatt-hour if the 60-megawatt commercial power system was added. The rate estimate varies depending on financing assumptions used such as loan amounts, interest rates, and required annual payments. The rate was reduced in cases where federal financing was provided at the Central Utah Project's authorized rate of 3.22 percent interest, and in one case where nonfederal financing was provided at an 8-percent interest rate. Annual revenues from power sales would range from $3.7 to $4 million.

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[2]Composite rates are an average of actual charges for power sold. See section 5 for a further discussion of composite rates.

AGENCY COMMENTS

In commenting on a draft of this report, the Department of the Interior observed that a CRSP power rate increase will be necessary to cover some irrigation costs of the Central Utah Project under any of the construction alternatives. This observation appears reasonable to us. (See app. V.)

The Department also commented that our report results in the somewhat misleading conclusion that a Diamond Fork power plant designed to produce commercial power could reduce the CRSP power rate. We disagree that this conclusion is implied. Instead, the report demonstrates in table 6.2 that the current CRSP rate of 9.92 mills per kilowatt-hour would be increased to a minimum of 10.66 mills per kilowatt-hour if the commercial power features we analyzed were constructed.

The Department also referred to the possibility that the Central Utah Project may be constructed without a Diamond Fork Power System. If so, the Department estimated the CRSP rate would be about 11 mills per kilowatt-hour. Our analysis of constructing a Diamond Fork Power System with commercial power shows that in five of the nine financing alternatives we considered, the CRSP rate would be less than 11 mills per kilowatt-hour. In four alternatives, the rate would be greater.

We requested written comments from the Department of Energy but none were provided. We obtained informal editorial and technical comments from the Western Area Power Administration that were considered in completing the report.

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Sections 1 through 6 of this fact sheet present more detailed responses for each question you asked us to address. To answer the questions, we used information from the Bureau of Reclamation, Upper Colorado Region, located in Salt Lake City, Utah, and Western Area Power Administration offices located in Salt Lake City and Golden, Colorado. In addition, we contacted representatives of 11 utility companies for rate information. Appendix I describes our scope and methodology in more detail. Appendixes II through V contain a list of CRSP projects, lists of CRSP power and water customers, and comments on this fact sheet from the Department of the Interior. Major contributors to this fact

sheet are listed in appendix VI. We performed our work between October 1988 and February 1989.

As arranged with your office, unless you publicly announce its contents earlier, we will not distribute this fact sheet further until 30 days from the date of this letter. At that time we will send copies to the Secretary of Energy, the Secretary of the Interior, appropriate congressional committees, and other interested parties.

If we can be of any further assistance, please call me on (202) 275-1441.

Sincerely yours,

Keith O. Fultz
Director, Energy Issues

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TABLES

FIGURES

ABBREVIATIONS

CRSP	Colorado River Storage Project
CUP	Central Utah Project
GAO	General Accounting Office
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
M&I	municipal and industrial

SECTION 1

OVERVIEW OF THE COLORADO RIVER STORAGE PROJECT AND THE CENTRAL UTAH PROJECT

QUESTION

Describe the Colorado River Storage Project (CRSP) and the Central Utah Project (CUP), including how and to whom power and water are sold, what the gross power revenues are (1980-87), and what is done with revenues.

COLORADO RIVER STORAGE PROJECT

CRSP is a program to develop, and make available for use, the water resources of the upper Colorado River. It is one of the most complex and extensive river resource developments in the world. Its scope takes in the drainage of the Upper Colorado River Basin, an area about one-twelfth the size of the continental United States. The Upper Basin is located in Arizona, Colorado, New Mexico, Utah, and Wyoming.

CRSP's four large water storage units equalize the erratic flows of the Colorado River and its main tributaries.[1] This equalized flow enables the upper basin states to make their water delivery commitments each year to the lower basin states--Arizona, California, and Nevada. Water remaining in the Upper Basin that is not needed to meet these delivery commitments is used to serve farmers, municipalities, and industries. This water is delivered through CRSP's participating projects. There are 21 authorized CRSP participating projects. (See app. II.)

CRSP water storage units and participating projects are "linked" in that revenue from hydroelectric power sales, generated primarily from water storage unit power plants, helps defray the irrigation investments of the participating projects. In other words, the participating projects "participate" in the revenue from CRSP power sales to help pay for their irrigation investment.

As of September 30, 1987, the Bureau of Reclamation estimated the total cost of CRSP's water storage units and participating

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[1]CRSP's four multipurpose water storage units--usually referred to as the CRSP mainstem project--are Aspinall, Flaming Gorge, Glen Canyon, and Navajo. These units consist of reservoirs, dams, and power plants, except for Navajo, which has no power generation installed.

projects at about $5.5 billion.[2] Of this amount, $2.3 billion is for the Central Utah Project, the largest of the 21 participating projects. About $3 billion of the $5.5 billion estimated cost had been incurred as of September 30, 1987.

CENTRAL UTAH PROJECT

The CUP will obtain water from Utah Lake, the Provo River, and water tributaries to the Colorado River for use in the Uintah and Bonneville Basins of northern Utah. Water developed by this project is for irrigation, and municipal and industrial (M&I) uses. It could also be used for the production of hydroelectric power. The project is also intended to benefit fish, wildlife, and recreation programs, as well as improve water quality, conservation, and flood control.

CUP is divided into separate units, as shown in figure 1.1. The largest of the five units is the Bonneville Unit. Basically, the Bonneville Unit is designed to collect water in the Uintah Basin and transport it through the Wasatch Mountains to the Bonneville Basin through a complex system of aqueducts, tunnels, and canals. The water will be used for municipalities, industries, irrigation, and power generation. The CUP's other four units will also provide water for municipalities, industries, and irrigation.

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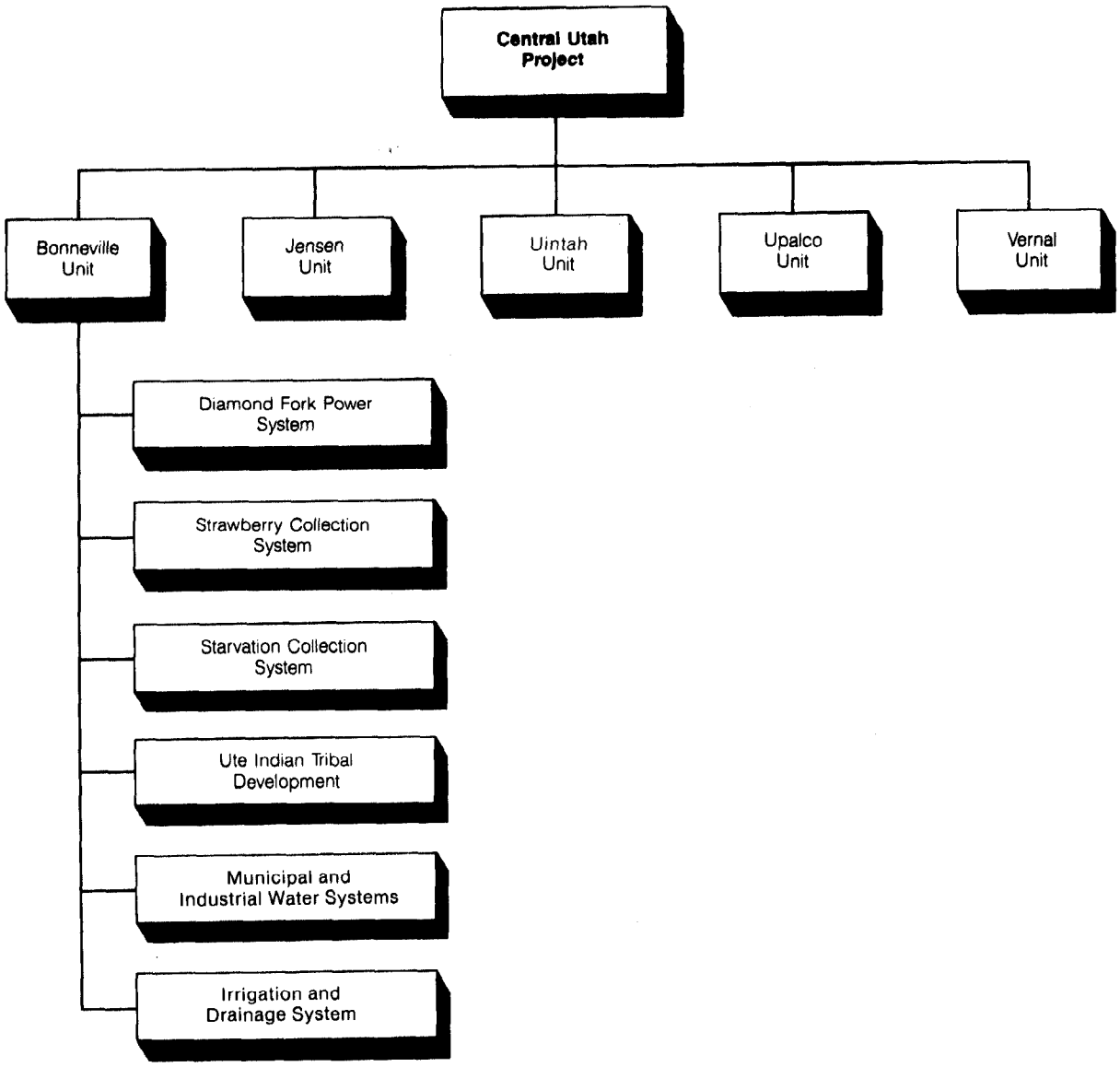
[2]Financial data for five participating projects are not included in this report. Five projects (Fruitland Mesa, La Barge, San Miguel, Savery-Pot, Hook, and West Divide) have been deferred indefinitely because they have been found economically infeasible by the Bureau of Reclamation. The estimated costs associated with the deferred projects is $807.2 million.

Figure 1.1: Units and Systems of the Central Utah Project



The Bonneville Unit is divided into six systems. It will include six new reservoirs; the enlargement of an existing reservoir; more than 200 miles of aqueducts, tunnels, and canals; seven pumping stations; 162 miles of drains and natural channel improvements; and at least one power plant. Of the six systems shown in figure 1.1, the Starvation and Strawberry Collection Systems and the Ute Indian Tribal Development are essentially complete. The other three systems are being designed and developed.

The Diamond Fork Power System, one of the proposed systems within the Bonneville Unit, would be located in the Wasatch Mountains of north-central Utah. It would include at least one power plant to supply about 18 megawatts of hydroelectric power to operate irrigation and drainage pumps. The estimated cost of the system is $287.8 million. Additional power-generating facilities or plants could be added to the system to generate commercial power.

HOW AND TO WHOM POWER AND WATER ARE SOLD

The Western Area Power Administration sells power produced by CRSP either on a "firm" or "non-firm" basis. Western guarantees that firm power will be available on demand when needed by the customer and sells power not needed to satisfy firm power commitments on a non-firm basis.

Firm power is sold to preference customers. Preference customers are defined as municipalities, cooperatives, or other nonprofit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936. Current firm power contracts with CRSP preference customers expire on September 30, 1989. Contracts issued after this date will be for 15 years, subject to adjustment in year 10 of the contract.

Western sold CRSP power to 72 firm power preference customers located in Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming in fiscal year 1987. Some of Western's preference customers also purchased non-firm power. In addition, non-firm power was sold to customers in Arizona, California, Nevada, Texas, and Utah. After September 30, 1989, Western plans to sell firm power to an additional 26 preference customers. A list of each of these customer categories is provided in appendix III.

Most CRSP preference customers have obtained only a portion of their total energy needs from CRSP power, as shown in table 1.1.

Table 1.1: Percentage of Firm Energy Supplied by CRSP to Preference Customers

Percent of energy supplied by CRSP	Percent of Customers
0.01-25	32
25.01-50	32
50.01-75	25
75.01 or more	11
Total	100

Source: GAO analysis of 1982 Western data--the latest data available.

The Bureau of Reclamation sells CRSP water to irrigators at rates based on their ability to pay. Reclamation also sells CRSP water to municipal and industrial water users. Rates for these water users are designed to recover the federal reimbursable investment in industrial and municipal water facilities--including interest, and operating and maintenance costs--as well as any other project costs to be paid by these users. In 1987, Reclamation had contracts with 52 municipal and industrial water users and irrigators for CRSP water. A list of CRSP water users is provided in appendix IV.

POWER REVENUES[3]

Since 1980, CRSP gross power revenues have averaged about $106 million annually. Table 1.1 presents CRSP gross power revenues in more detail.

[3]The Subcommittee did not ask us to develop data about revenues from the sale of water.

Table 1.2: CRSP Power Revenues, Fiscal Years 1980-87

Year	Revenues (in millions)
1980	$ 77.330
1981	77.190
1982	73.729
1983	105.530
1984	120.742
1985	151.873
1986	128.548
1987	109.508[a]

[a]In 1988, Western reported that the Financial Management System that generated the 1987 gross revenue data had a material internal control weakness. As a consequence, the information for 1987 may not be reliable.

Source: Western Area Power Administration financial statements.

There are five power plants on the mainstem project that generated power sold commercially in fiscal year 1987. As shown in table 1.3, the Glen Canyon power plant produced the majority of that power.

Table 1.3: Net Generation of CRSP Power Plants, Fiscal Year 1987

Power plants	Net generation[a] (in millions of kWh[b])
Aspinall Unit:	
Blue Mesa	342.7
Crystal	232.2
Morrow Point	424.1
Flaming Gorge	588.3
Glen Canyon	6,538.6
Total	8,125.9

Note: The Navajo storage unit does not contain a power plant.

[a]Net generation reflects total generation at the power plant less plant use.

[b]Kilowatt-hour--The common unit of electric energy equal to 1 kilowatt of power supplied for 1 hour.

Source: Western's 1987 annual report.

Western's rates for CRSP power are intended to ensure that power sale revenues are sufficient to recover the federal investment in power facilities; operation, maintenance, replacement, and emergency costs; and a portion of the federal investment for irrigation. The irrigation investment to be repaid from power revenues is determined by the Bureau of Reclamation. This investment amount is determined by an economic analysis of the extent to which irrigators have the ability to pay project costs allocated to providing irrigation benefits. Those costs beyond irrigators' ability to pay are then assigned by Reclamation for recovery through power sales revenues.

Western determines its electric power rates by using the repayment study method. These studies are designed to demonstrate revenue adequacy by showing the recovery of annual costs each year. Repayment studies also contain a plan for amortization payments governed by the requirement for repaying the federal investment within 50 years.

Rates are set at the lowest possible level consistent with sound business practices. Rates are based on the revenues needed to make annual revenues pay for the costs of operation and maintenance, purchased and exchanged power, transmission service, and amortization of the federal investment. The federal investment is the lowest category of expense, and it does not need to be repaid on a fixed schedule. The only requirement is that the project be repaid over its scheduled useful life, not to exceed 50 years.

Interest expenses are included in repayment as follows. Annual interest expenses on the federal investment during the construction period are capitalized. That is, the interest is accrued over the construction period, added to the other construction costs, and considered part of the total federal investment. Also, for power investments, interest is charged annually on the unpaid balance of the federal investment. However, for irrigation investments, no interest is charged on unpaid irrigation construction costs.

REVENUE USE

Revenues from power and water sales are used to pay the federal government for reimbursable project costs. Reimbursable costs are those associated with irrigation, power, municipal and industrial water investments, and a portion of salinity control costs; replacement costs; and a portion of the system's operating costs. Nonreimbursable costs include investments in fish and wildlife, recreation, and highway improvements. These costs are paid from federal appropriations and contributions from others, such as states and municipalities.

Revenues from the sale of electric power and water are first used to pay operating, maintenance, emergency, and replacement costs. Thereafter, revenues are used to repay power investment costs with interest; municipal and industrial water, and some salinity control investment costs with interest; and irrigation investment costs without interest. Excess revenue deposited in the U.S. Treasury is apportioned among the states as follows: Colorado (46 percent), Utah (21.5 percent), New Mexico (17 percent) and Wyoming (15.5 percent). Apportioned revenue is designated to repay irrigation costs of participating projects within these states.

SECTION 2

INVESTMENT IN THE COLORADO RIVER STORAGE PROJECT AND THE CENTRAL UTAH PROJECT

QUESTION

What is the amount of reimbursable and nonreimbursable investment (cost) in the Colorado River Storage Project and the Central Utah Project?

ANSWER

As of September 30, 1987, the federal government had invested about $2.5 billion in CRSP, including $815.7 million in the CUP. The CUP's Bonneville Unit, which is the largest unit, accounts for $724.9 million ($553.9 million reimbursable and $171 million nonreimbursable) of the project's total investment. Table 2.1 presents more information on CRSP's total investment.

Table 2.1: Total CRSP Investment Costs as of September 30, 1987

Cost component	Participating projects: Mainstem	CUP	Other	Total
	(in millions)			
Reimbursable:				
Irrigation	$110.096[a]	$355.810	$352.000	$ 817.906
Power	600.625	.000	8.110	608.735
M&I water[b]	6.786	262.546	103.911	373.243
Total	717.507	618.356	464.021	1,799.844
Nonreimbursable:				
Irrigation[c]	0.048	0.000	242.412[c]	242.460
Power	.184[d]	.000	.000	.184
Fish and wildlife	40.016	128.170	92.276	260.462
Recreation	42.724	31.167	34.771	108.662
Other[e]	7.679	38.006	78.263	123.948
Total	90.651	197.343	447.722	735.716
Total investment costs	$808.158	$815.699	$911.743	$2,535.600

[a]These costs are reimbursed from power and municipal and industrial water revenues, according to the Department of the Interior.

[b]Municipal and industrial water.

[c]This is the cost for the Navajo Indian Irrigation Project. Such costs are not reimbursable unless the lands involved are no longer owned by Indians.

[d]This amount is the federal contribution for construction of an airport extension attributed to reimburseable functions, according to a Bureau of Reclamation financial statement.

[e]Includes costs for such components as flood control, highway improvements, and cultural and a portion of municipal and industrial water costs for the Dallas Creek Project.

Source: GAO analysis of Bureau of Reclamation data.

SECTION 3

INVESTMENT REPAYMENT

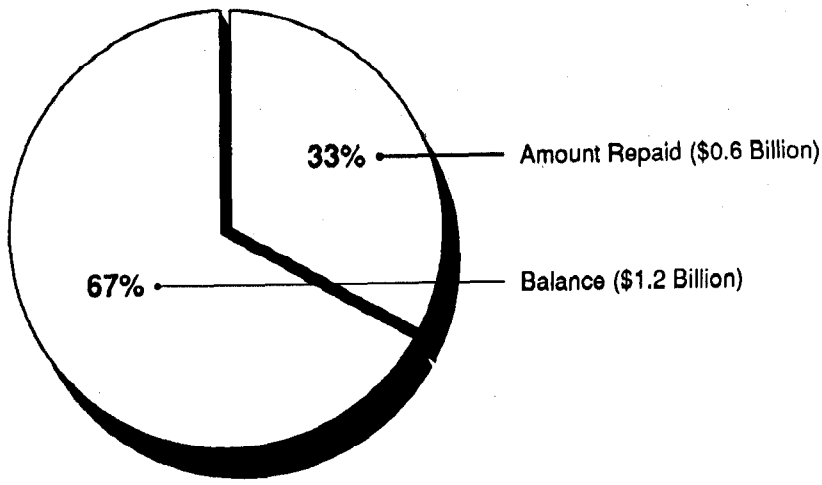
QUESTION

According to Bureau of Reclamation records, how much of the reimbursable investment has been repaid? When is the CRSP investment scheduled to be paid off? How much revenue is expected to be raised by CRSP and from whom?

ANSWER

According to Bureau of Reclamation records, about $630 million of the $1.8 billion of CRSP reimbursable costs incurred as of September 30, 1987, had been repaid to the Treasury. The Bureau estimates reimbursable costs will total $3.9 billion by the time CRSP is completed. Thus, about 46 percent of the total estimated reimbursable costs for CRSP had been incurred as of September 30, 1987. Figure 3.1 presents the status of repayment for the reimbursable investment made in CRSP as of September 30, 1987. Table 3.1 presents details by principal cost component.

Figure 3.1: CRSP Reimbursable Investment and Amount Repaid as of September 30, 1987



Total Actual Reimbursable Cost = $1.8 Billion

Table 3.1: Actual Reimbursable Costs and Repayment for CRSP as of September 30, 1987

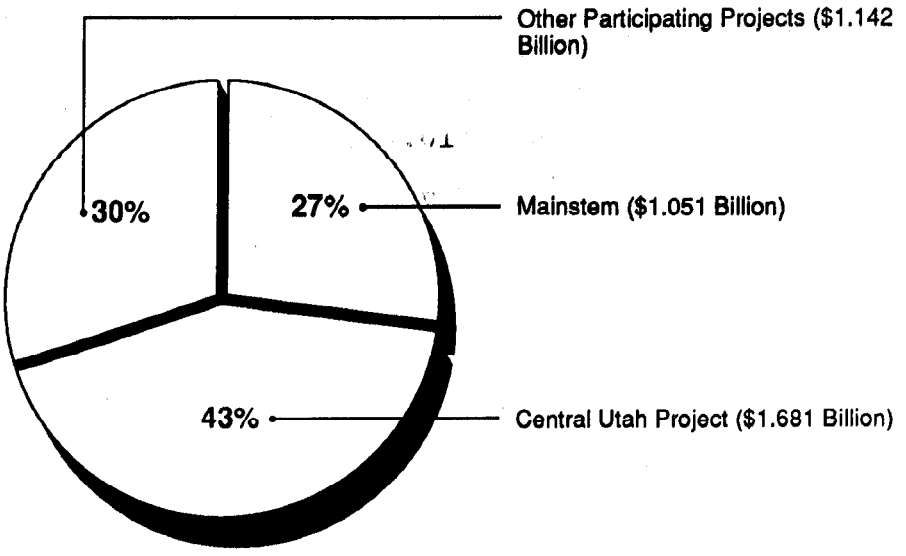
CRSP feature	Actual reimbursable costs	Amount repaid	Balance
	(in millions)		
Mainstem:			
Irrigation	$ 110.096	$ 0.363	$ 109.733
Power	600.625	588.162	12.647
M&I Water[a]	6.086	10.705	(3.919)
Total	717.507	599.230	118.277
CUP:			
Irrigation	355.810	2.002	353.808
M&I[a]	262.546	12.142	250.404
Total	618.356	14.144	604.212
Other:			
Irrigation	352.000	6.794	345.206
Power	8.110	.060	8.050
M&I	103.911	9.747	94.164
Total	464.021	16.601	447.420
Total	$1,799.884	$629.975	$1,169.909

[a]Municipal and industrial water.

Source: GAO analysis of Bureau of Reclamation data.

Figure 3.2 presents Bureau estimates of reimbursable investment costs, by project, which it expects will eventually be incurred by CRSP. Table 3.2 presents details by cost component of the CRSP reimbursable costs expected to be eventually incurred. The data are as of September 30, 1987.

Figure 3.2: Total Estimated Reimbursable Costs for All Projects Under CRSP



Total Estimated Reimbursable Costs for All Projects-$3.874Billion

Table 3.2: Expected CRSP Reimbursable Costs

Project feature	Mainstem	Central Utah project	Other	Total
	(in millions)			
Power	$ 933.012	$ [a]	$ 41.505	$ 974.517
Irrigation	110.433	1,091.392	883.400	2,085.225
M&I water	7.487	589.741	217.148	814.376
Total	$1,050.932	$1,681.133	$1,142.053	$3,874.118

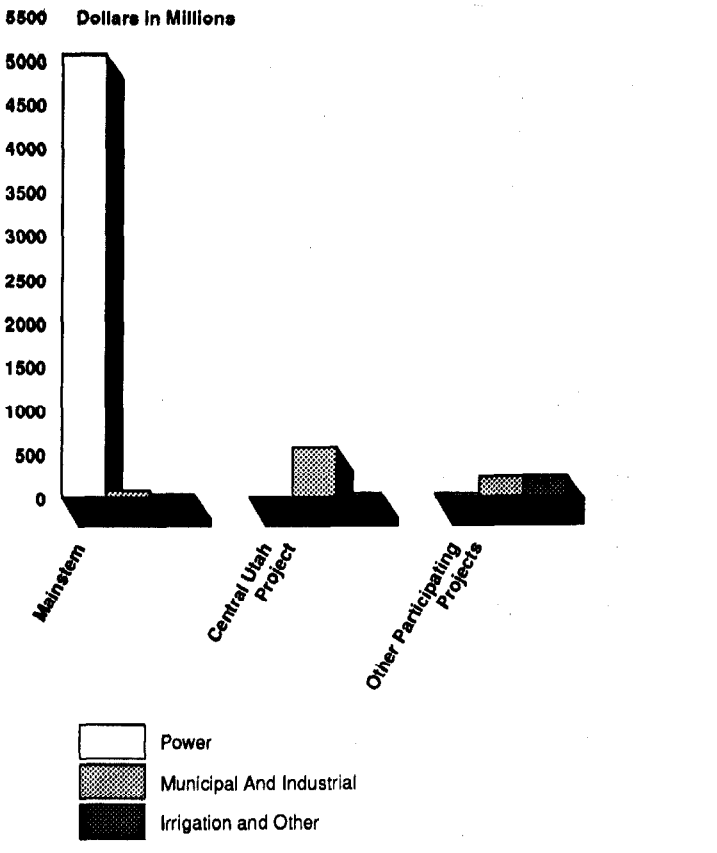
[a]No commercial power was planned for CUP. Planned power facilities were for project pumping (primarily irrigation).

Source: GAO analysis of Bureau of Reclamation data.

SOURCES OF REPAYMENT REVENUES

Reimbursable costs for CRSP are expected to be repaid with revenues generated primarily from power and municipal and industrial water sales. As of September 30, 1987, Bureau of Reclamation estimates show that most revenues for CRSP are to come from power users (80.6 percent) and municipal and industrial water users (14.2 percent); irrigators and others are expected to contribute the remaining revenues (5.2 percent). Details of revenue sources for the mainstem project, CUP, and the remaining participating projects are presented in figure 3.3 and table 3.3. Figure 3.3 shows that the mainstem project will provide most of the CRSP revenues. Table 3.3 presents revenues that will be collected until each of the CRSP projects is paid off. The data are as of September 30, 1987.

Figure 3.3: Estimated Revenues by Source and by Project Under CRSP



Total Estimated Colorado River Storage Project Revenues = $6.329 Billion

Table 3.3: Estimated CRSP Revenues by Source

Revenue source	Mainstem	CUP	Other	Total
	(in millions)			
Power users	$5,063.046	$ 0.000	$ 41.445	$5,104.491
Irrigators	.000	38.775	44.410	83.185
M&I water users	85.229	579.314	232.808	897.351
Other[a]	38.092	11.478	194.353	243.923
Total	$5,186.367	$629.567	$513.016	$6,328.950

[a]Other revenue sources include contributions from others such as states, counties, cities, and the Colorado River Development Fund.

Source: GAO analysis of Bureau of Reclamation data.

REPAYMENT OF THE CRSP INVESTMENT

Reimbursable costs for CRSP power and municipal and industrial water facilities are required to be repaid by law (43 U.S.C. 620d) within a period not exceeding 50 years from the date they are completed. Irrigation costs must be repaid within 50 years after construction is completed and also after any developmental period, up to a maximum of 10 years.

According to the Bureau of Reclamation, the estimated power costs of $974.5 million for the mainstem project and its participating projects will be repaid by the year 2000. Irrigation and municipal and industrial water costs will be repaid as shown in table 3.4.

Table 3.4: Years in Which CRSP Costs Will Be Paid Off

Project	Year	
	Irrigation	M&I
CRSP (mainstem)	2002	1984
Participating projects		
Central Utah Project Units:		
Vernal	2016	2002
Bonneville	2090	2045
Jensen	2033	2048
Uinta	2075	2040
Upalco	2043	2004
Animas La Plata	2055	2052
Bostwick Park	2029	a
Dallas Creek	2041	2048
Dolores	2051	2052
Eden	2029	a
Emery County	2020	2020
Florida	2021	a
Hammond	2032	a
Lyman	2036	2040
Paonia	2040	a
San Juan-Chama	2032	2022
Seedskadee	2017	2024
Silt	2021	a
Smith Fork	2017	a

[a]Project does not include investments for municipal and industrial water.

Source: Bureau of Reclamation.

SECTION 4

VALUE OF COLORADO RIVER STORAGE PROJECT'S POWER ASSETS

QUESTION

To the extent that data are available, what is the value of the power assets within CRSP?

ANSWER

Neither the Western Area Power Administration nor the Bureau of Reclamation has performed a detailed assessment of the value of CRSP power assets. Therefore, our work was confined to information that could be obtained from annual financial records and statements. We obtained two estimates of the book value, one from Western and one from the Bureau of Reclamation.

Western's financial statements report the book value of CRSP's power assets as $741.8 million, as of September 30, 1987. Table 4.1 shows these assets in detail.

Table 4.1: CRSP Power Assets as of September 30, 1987

Assets	Value (in millions)
Plant-in-service[a]	$650.766
Accumulated depreciation[b]	(39.189)
Net plant-in-service	611.577
Construction work-in progress[c]	123.277
Capitalized moveable[d] equipment	6.974
Total	$741.778[e]

[a]Plant-in-service refers to the total investment in power plants and transmission facilities, such as transmission lines, substations, switchyards, and metering equipment.

[b]Accumulated depreciation is based on the anticipated service life of the power system. On a composite system basis, the service life is about 75 years.

[c]Construction work-in-progress refers to the costs for facilities that have not yet been transferred to plant-in-service. It also includes capitalized interest, which will be amortized over the life of the system when the facilities are transferred to plant-in-service.

[d]Capitalized moveable equipment is the net book value of equipment owned by the federal government. Depreciation has been deducted from the equipment's original cost.

[e]In 1988, Western reported that the Financial Management System that generated the 1987 financial statements had a material internal control weakness. As a consequence, the information for 1987 may not be reliable.

Another view of the value of CRSP assets is provided by Bureau of Reclamation financial statements for CRSP power assets, which are required by 43 U.S.C. 620e. These statements show the value of the CRSP electric plant, at the end of fiscal year 1987, as $431.3 million. According to a Bureau of Reclamation official, this amount represents only those costs that are totally electric plant costs and does not include costs that would be allocated to power from multipurpose plant and construction work-in-progress.

SECTION 5

FEDERAL AND NONFEDERAL POWER RATES

QUESTION

What were CRSP composite power rates between 1980 and 1987? Are these rates comparable to the power rates of other Western projects, other federal power administrations, and nonfederal power sold within Western's power marketing area?

CRSP COMPOSITE POWER RATES

The current composite power rate for CRSP wholesale firm power is 9.92 mills per kilowatt-hour.[1] Rates for CRSP wholesale firm power ranged from 6.15 mills per kilowatt-hour to the current 9.92 mills per kilowatt-hour during 1980 through 1987. Table 5.1 presents details of these rates.

Table 5.1: CRSP Power Rates for Fiscal Years 1977-88

Fiscal year	Capacity (per kW month)	Energy (mills per kW hour)	Composite (mills per kW hour)
July 1977 through Jan. 1981	$1.340	3.4	6.15
Jan. 1981 through May 1983	1.655	4.0	7.89
June 1983 through Dec. 1988	2.090	5.0	9.92

Source: Western Area Power Administration.

The composite rate is a weighted average of the capacity and energy charges collected per kilowatt-hour sold. Composite rates should not be used for estimating customers' power bills because power bills are computed on the basis of a customer's actual capacity and energy charges. The capacity charge is based on the customer's peak monthly demand, measured in terms of kilowatts. The energy charge, on the other hand, is a charge for the energy taken from the system and is measured in kilowatt-hours.

---

[1] A mill is one-tenth of 1 cent, or $0.001.

POWER RATES

Table 5.2 presents power rates for CRSP, other Western projects, other federal power administrations, and 11 nonfederal utilities that sell power in Western's marketing area. See appendix I for details of the methodology used to develop these rates.

Table 5.2: Average Wholesale Composite Firm Power Rates for Federal and Nonfederal Utilities, 1987

Federal	Composite wholesale firm power rate (mills/kWh)
Western projects:	
CRSP	9.92
Pick-Sloan Missouri Basin:	
Eastern Division	7.14
Western Division	8.54
Boulder Canyon	6.81
Parker-Davis	8.55
Central Valley	39.63
Collbran	21.80
Rio Grande	36.92
Bonneville Power Administration	21.09
Southeastern Power Administration:	
Georgia-Alabama	26.06
Cumberland Basin	10.38
Kerr-Philpott	16.69
Jim Woodruff	11.06
Southwestern Power Administration	28.00
Nonfederal	
Arizona Public Service Co.	46.53
Basin Electric Power Cooperative	54.91
Colorado Ute Electric Association, Inc.	39.13
Pacific Gas and Electric Co.	27.98
Pacific Power and Light Co.	29.34
Plains Electric Generation & Transmission Cooperative, Inc.	64.43
Public Service Co. of Colorado	41.96
Public Service Co. of New Mexico	76.07
Southern California Edison Co.	70.80
Tri-State Generation & Transmission Association, Inc.	44.65
Utah Power and Light Co.	34.22

Source: GAO analysis based on information described in app. I.

Western Area Power Administration officials suggested that we caution readers that comparisons of these composite rates are not appropriate because they do not account for differences in each utility's power systems, such as diverse range of powerplant types, efficiency, age, size, and fuel sources. We recognize that the data presented do not provide a basis for determining the legitimacy or appropriateness of the differences in composite rates shown in the table. Nevertheless, the data reasonably indicate the magnitude of differences in the power rates of various utilities.

With respect to federal power rates, however, we have found in past work that there are instances where all costs of producing federal power are not reflected in rates charged by federal power-marketing administrations. These instances, in our view, contribute to the relatively low rates for federal power when compared with the rates of nonfederal utilities.

SECTION 6

EFFECT OF ADDING COMMERCIAL POWER FEATURES TO THE DIAMOND FORK POWER SYSTEM

QUESTION

What would be the effect on the CRSP power rate and estimated net revenues if commercial power features were added to the Bonneville Unit's proposed Diamond Fork Power System?

ANSWER

To answer this question, we identified one possible commercial power plant configuration for the Diamond Fork system on the basis of Bureau of Reclamation data. Then, we obtained estimates of the effect of financing this power plant on CRSP's electric power rate and revenues. At our request, Western estimated the effects on the basis of several financing options, including federal and nonfederal financing scenarios. Western used its standard power rate and repayment study methodology in making the estimates.

Nonfederal financing was included among the scenarios because there have been nonfederal entities that have expressed an interest in providing financing. Nonfederal financing responds to the desire of the executive branch and the Congress to secure nonfederal participation in water resource projects and to ensure project completion.

CURRENT DESIGN OF DIAMOND FORK

The design of the Bonneville Unit's Diamond Fork Power System has not been completed, although numerous system configurations have been proposed since 1964. These proposals have ranged from the current plan for the 18-megawatt system for pumping water for irrigation to an 1,158-megawatt system that would also generate power for sale. The currently planned system's $1.91 billion estimated cost would be treated as an investment in municipal and industrial water and irrigation, with the majority of the reimbursable investment to be repaid by revenues from the sale of CRSP power. The Department of the Interior noted that a May 1988 draft plan for the Central Utah Project proposes to eliminate the Diamond Fork Power System from the project plans.

Western has estimated the effect that construction of the Bonneville Unit with Diamond Fork would have on CRSP power rates. In Western's 1988 Preliminary CRSP Rate and Repayment Study, which includes a Diamond Fork investment for project pumping only, the required CRSP composite power rate would be 11.08 mills per kilowatt-hour. This estimate is the baseline against which to

compare the rate impact of adding commercial power to the Bonneville Unit's Diamond Fork Power System.

DIAMOND FORK ALTERNATIVE WITH COMMERCIAL POWER

The Diamond Fork alternative we studied would replace the proposed 18-megawatt system in the Bonneville Unit's Diamond Fork Power System with a 79.1-megawatt power system, which would allow revenues from the sale of Diamond Fork power to be available to repay costs of the system. With the 79.1-megawatt system, the Bonneville Unit's power costs would increase from an estimated $11.4 million to $130.6 million. Table 6.1 presents details about the Diamond Fork power plant alternative that we studied. These data were used as constants for each of the financing scenarios we studied. System capacity would be increased by 61.1 megawatts compared with the current plan. We used 1996 as the estimated in-service date of the system.

Table 6.1: Summary of Alternative Diamond Fork Power System

Cost assumptions	Costs (in millions)
Portion of project investment to be repaid by power:	
Irrigation investment	$1,124.7
Power investment	130.6
Total	$1,255.3
Annual operation, maintenance, and replacement cost	$0.5

Capacity assumptions	Megawatts	MWH/year
Installed capacity		
Commercial	61.1	285,400
Project Pumping	18.0	21,500
Total	79.1	306,900

Source: GAO analysis of Bureau of Reclamation and Western Area Power Administration data.

FINANCING SCENARIOS AND RESULTS

At our request, Western computed the effect of constructing the alternative Diamond Fork system on CRSP power rates and revenues using the following financing scenarios:

-- 100-percent federal financing,

-- a combination of 50-percent federal and 50-percent nonfederal financing (according to Bureau of Reclamation officials, this financing scenario is similar to those previously proposed by nonfederal entities), and

-- 100-percent nonfederal financing.

In each of these scenarios, $1.255 billion of the Bonneville Unit's cost was repaid by power users.

Table 6.2 presents the results of Western's computations using a range of interest rates and repayment terms. It shows that the CRSP power rate would be between 10.66 and 11.34 mills per kilowatt-hour. The table also shows that, under the various scenarios, the CRSP composite power rate would be lower than the 11.08 mills per kilowatt-hour rate currently estimated for CRSP (if only power facilities for project pumping are constructed), unless the financing was 100-percent nonfederal, with an interest rate of 9 percent or more.

These results are influenced in five cases by federal financing. Federal financing includes the low federal interest rate authorized for CRSP projects and a 50-year repayment term. Also, in one scenario with 100-percent nonfederal financing, an interest rate of 8 percent is low enough to result in a rate decrease. In the three other scenarios, interest rates of 9 to 11 percent on nonfederal financing result in annual payments that require a power rate increase.

Table 6.2: Diamond Fork Financing Scenarios and Rate Impact

Financing	Cost subject to interest (in millions)	Interest rates (percent)	Repayment term (years)	Required annual payment (millions)[a]	Required CRSP rate (mills/kWh)
100% federal	$130.6	3.22	50	[b]	10.66
Combination of federal/ nonfederal					
Federal	65.2	3.22	50	[b]	[c]
Nonfederal	65.4	8.00	30	$ 5.807	10.84
		9.00	30	6.363	10.88
		10.00	30	6.934	10.92
		11.00	30	7.519	10.96
100% nonfederal	130.6	8.00	30	11.601	11.04
		9.00	30	12.712	11.14
		10.00	30	13.854	11.24
		11.00	30	15.022	11.34

[a]Assumes equal annual interest and principal payments for nonfederal financing.

[b]No annual payment on the principal investment is required under federal financing.

[c]The corresponding rate is shown below along with the interest rates applicable. to the nonfederally financed portion of the investment.

Source: GAO analysis of Bureau of Reclamation data and Western Area Power Administration CRSP rate and repayment studies.

Table 6.3 shows the estimated gross revenues resulting from the sale of commercial power for each scenario. These revenues are based upon the CRSP composite rates shown in table 6.2.

Table 6.3: Estimated Gross Revenues From Diamond Fork Power System Under Various Financing Assumptions

Financing assumption	Estimated annual revenue
100% federal at 3.22% interest	$ 3,785,952
Combination--federal at 3.22% interest and nonfederal at:	
8%	3,849,880
9%	3,864,086
10%	3,878,293
11%	3,892,499
100% nonfederal at:	
8%	3,920,911
9%	3,956,427
10%	3,991,942
11%	4,027,458

Source: Western Area Power Administration data.

Under the current 18.1-megawatt power system design and the 79.1-megawatt power system financial scenarios, mainstem revenues would be needed to repay the costs of the Bonneville unit with its Diamond Fork power system. These revenues would be needed because under the 18.1-megawatt system, power revenues would not be generated and under the 79.1-megawatt alternative we studied, revenues from the sale of power from Diamond Fork would be insufficient to pay for its costs within the repayment period. Under the assumptions we used, power revenues from the mainstem and Diamond Fork would be sufficient to repay those power costs that are federally financed by the end of fiscal year 2013. Nonfederally financed costs would be repaid in total by the year 2025 with our assumptions of 30-year financing and equal interest and principal payments. Table 6.4 shows the estimated revenue the mainstem project would contribute to the repayment of Diamond Fork until its power features are repaid.

Table 6.4: Estimated Mainstem Revenue Contributions to Diamond Fork to Repay Power Feature Costs

Interest rate	Federal financing	Federal & nonfederal[a]	All nonfederal
	(in millions)		
3.22	$128.1	b	b
8.00	b	$167.6	$245.4
9.00	b	183.7	277.7
10.00	b	200.5	310.9
11.00	b	217.8	344.8

[a]Federal interest rate would be 3.22 percent.

[b]Not applicable.

Source: GAO analysis of Western Area Power Administration data.

SCOPE AND METHODOLOGY

We obtained information from the Bureau of Reclamation, Upper Colorado Region, located in Salt Lake City, Utah; and the Western Area Power Administration offices located in Salt Lake City and Denver, Colorado. We examined pertinent laws and reports. In addition, we contacted representatives of 11 utility companies for rate information. We performed our work between October 1988 and February 1989.

We generally relied on fiscal year 1987 financial and operating data on the CRSP mainstem and participating projects because complete fiscal year 1988 data were not available. When fiscal year 1988 data were available, we included them in our work.

The data presented on the amount of energy supplied by CRSP to its customers (table 1.1) were computed using data obtained from Western. With electricity use data that Western provided for each customer, we computed the "Percent of Firm Energy Supplied by the CRSP to Preference Customers" by dividing the contract rate of electricity delivered in megawatt hours by total annual megawatt hours.

Wholesale firm power composite rates (table 5.2) either were obtained from public sources or were computed on the basis of the revenues received from capacity and energy charges per kilowatt-hour sold. Composite rates were used because wholesale firm power rate schedules are not readily comparable. The composite rate facilitates this comparison.

The composite power rates presented in table 5.2 were obtained or arrived at in the following manner:

-- Western projects. These are published rates as shown in Western's annual reports.

-- Bonneville and Southwestern. Western obtained the average rate for us.

-- Southeastern projects. We computed the composite rates using the Southeastern Power Administration's 1987 Marketing Summary.

-- Nonfederal investor-owned utilities. We computed composite rates for these utilities using the Federal Energy Regulatory Commission's Form 1, for the year ending 1987. This calculation used the Form 1 schedule entitled "Sales for Resale" and was based on the energy and demand revenues

received per kilowatt-hour for each firm power customer and for the utility as a whole. We did not include amounts identified as "other charges" in our computation of composite rates because the basis for these charges was not identified.

-- Other nonfederal utilities. We followed the same procedures as for investor-owned utilities, except that we used the Rural Electric Association's Financial Operating Reports (Form 12), or annual reports submitted to public utility commissions.

The composite rate results we calculated for nonfederal utilities were confirmed with a representative from each utility to ensure that our estimate of their average wholesale firm power rate was reasonable and accurate.

PROJECT, STATUS, AUTHORIZING LAW, AND DATE FOR THE COLORADO RIVER STORAGE PROJECT AND ITS PARTICIPATING PROJECTS (AS OF SEPT. 30, 1987)

Project	Status	Public Law	Date
CRSP (mainstem)	UC	84-485	Apr. 11, 1956
Participating projects			
Bostwick Park	C	84-485	Apr. 11, 1956
		88-568	Sept. 2, 1964
Eden	C	81-132	June 28, 1949
Florida	C	84-485	Apr. 11, 1956
Hammond	C	84-485	Apr. 11, 1956
Paonia	C	80-117	June 25, 1947
		84-485	Apr. 11, 1956
San Juan-Chama	C	87-483	June 13, 1962
Silt	C	84-485	Apr. 11, 1956
Smith Fork	C	84-485	Apr. 11, 1956
Central Utah:			
Vernal Unit	C	84-485	Apr. 11, 1956
Jenson Unit	UC	84-485	Apr. 11, 1956
Bonneville Unit	UC	84-485	Apr. 11, 1956
Upalco Unit	UC	84-485	Apr. 11, 1956
Uintah Unit	UC	90-537	Sept. 30, 1968
Animas-LaPlata	UC	90-537	Sept. 30, 1968
Dallas Creek	UC	90-537	Sept. 30, 1968
Dolores	UC	90-537	Sept. 30, 1968
Emery County	UC	84-485	Apr. 11, 1956
Lyman	UC	84-485	Apr. 11, 1956
Seedskadee	UC	84-485	Apr. 11, 1956
Navajo Indian Irrigation	UC	84-485	Apr. 11, 1956
		87-483	June 13, 1962
Fruitland Mesa	D	88-568	Sept. 2, 1964
		84-485	Apr. 11, 1956
LaBarge	D	84-485	Apr. 11, 1956
San Miguel	D	90-537	Sept. 30, 1968
Savery-Pot Hook	D	88-568	Sept. 2, 1964
		84-485	Apr. 11, 1956
West Divide	D	90-537	Sept. 30, 1968

Legend:
C = completed.
UC = under construction.
D = deferred.

COLORADO RIVER STORAGE PROJECT POWER CUSTOMERS

LONG-TERM FIRM POWER PREFERENCE CUSTOMERS (FISCAL YEAR 1987)

Arizona

1 Ak-Chin Indian Community
2 Arizona Power Pooling Association
3 Chandler Heights Citrus Irrigation District
4 Colorado River Irrigation Power Project
5 Electrical District #3, Pinal County
6 Electrical District #4, Pinal County
7 Electrical District #5, Maricopa County
8 Electrical District #5, Pinal County
9 Electrical District #6, Pinal County
10 Electrical District #7 Maricopa County
11 Maricopa County Municipal Water Conservation District Number One
12 Navajo Tribal Utility Authority
13 Ocotillo Water Conservation District
14 Page, City of
15 Queen Creek Irrigation District
16 Roosevelt Irrigation District
17 Roosevelt Water Conservation District
18 Safford, City of
19 Salt River Project
20 San Carlos Irrigation Project
21 San Tan Irrigation District
22 Thatcher, Town of
23 Wellton-Mohawk Irrigation and Drainage District
24 Williams Air Force Base
25 Yuma Proving Ground (U.S. Army)

Colorado

26 Center, City of
27 Colorado Springs, City of
28 Delta, City of
29 Delta-Montrose Electric Association
30 Empire Electric Association, Inc.
31 Fleming, Town of
32 Fort Morgan, City of
33 Frederick, Town of
34 Grand Valley Rural Power Lines, Inc.
35 Gunnison, City of
36 Gunnison County Electric Association, Inc.
37 Haxtun, Town of

APPENDIX III

38 Holy Cross Electric Association, Inc.
39 Holyoke, City of
40 Intermountain Rural Electric Association
41 La Plata Electric Association, Inc.
42 Lamar Utilities Board
43 Oak Creek, Town of
44 Platte River Power Authority
45 Pueblo Army Depot
46 San Isabel Electric Services, Inc.
47 San Luis Valley Rural Electric Coop., Inc.
48 San Miguel Power Association
49 Sangre De Cristo Electric Association, Inc.
50 Southeast Colorado Power Association
51 White River Electric Association, Inc.
52 Wray, City of
53 Yampa Valley Electric Association, Inc.
54 Yuma, City of

Nevada

55 Colorado River Commission

New Mexico

56 Aztec, City of
57 DOE--Albuquerque Operations Office
58 Farmington, City of
59 Plains Electric Generation & Transmission Cooperative, Inc.
60 Truth or Consequences, City of

Utah

61 Brigham City Corporation
62 Defense Depot Ogden
63 Deseret Generation and Transmission Cooperative
64 Dixie-Escalante Rural Electric Association, Inc.
65 St. George, City of
66 Utah Associated Municipal Power Systems
67 Utah Municipal Power Agency
68 Weber Basin Water Conservancy District

Wyoming

69 Torrington, Town of
70 Tri-State Generation and Transmission Association, Inc.
71 Wyoming Municipal Power Agency
72 Willwood Light & Power Company

APPENDIX III

PROSPECTIVE LONG-TERM FIRM POWER
PREFERENCE CUSTOMERS (POST 1989)

Colorado

1 Aspen, City of
2 Glenwood Springs, City of
3 Municipal Subdistrict Northern Colorado Water Conservancy District

New Mexico

4 Cannon Air Force Base
5 Central Valley Electric Cooperative, Inc.
6 Incorporated County of Los Alamos
7 Farmers' Electric Cooperative, Inc.
8 Gallup, City of
9 Holloman Air Force Base
10 Lea County Electric Cooperative, Inc.
11 Raton, City of
12 Roosevelt County Electric Cooperative, Inc.
13 Sandia National Laboratory, Kirtland Air Force Base

Utah

14 Blanding, City of
15 Central Utah Water Conservancy District
16 Enterprise, City of
17 Helper, City of
18 Hill Air Force Base
19 Hurricane, City of
20 Kanab, City of
21 Panguitch, City of
22 Price, City of
23 Santa Clara, City of
24 Tooele Army Depot
25 University of Utah
26 Utah State University
27 Washington, City of

Non-Firm Power Only Customers (Fiscal Year 1987)

1 Anaheim, Calif.
2 Arizona Public Service
3 El Paso Electric Co.
4 Imperial Irrigation District
5 Los Angeles, Calif.
6 Nevada Power Company
7 Riverside, Calif.
8 San Diego Gas & Electric Company
9 Southern California Edison
10 Tucson Electric Power
11 Utah Power & Light Co.

APPENDIX IV

COLORADO RIVER STORAGE PROJECT WATER CUSTOMERS

Arizona

1 Page, City of
2 Salt River Project

Colorado

3 Animas La Plata Water Conservancy District (WCD)
4 Bostwick Park WCD
5 Crawford WCD
6 Daisy Ditch Co.
7 Dolores WCD
8 Fire Mountain Canal & Reservoir Co.
9 Florida Canal Co.
10 Florida Cooperative Ditch Co.
11 Florida Farmers Ditch Co.
12 Florida WCD
13 Grand View Canal & Irrigation Co.
14 LeRoux Creek Water Users Association
15 Montezuma Valley Irrigation District
16 North Fork WCD
17 Silt WCD
18 Tri-County WCD

New Mexico

19 Albuquerque, City of
20 Benevolent Protective Order of Elks
Farmington Lodge No. 1747
21 Bernalillo, Town of
22 Bloomfield Refining
23 Burnett Construction
24 Espanola, Town of
25 Hammond Conservancy District
26 Los Lunas, Town of
27 M-K Ferguson Co.
28 Meridian Oil, Inc.
29 Nielsons' Inc.
30 North Heights Bloomfield Sanitation
31 Public Service Co. of New Mexico
32 San Juan Water Haulers
33 Santa Fe, City of
34 Sunterra Gas Processing Co.
35 Taos, Town of
36 Twining Water and Sanitation District
37 Utah International, Inc.

APPENDIX IV

Utah

38 Central Utah WCD
39 Cottonwood Creek Consolidated Irrigation Co.
40 Emery WCD
41 Ephraim Irrigation Co.
42 Huntington Cleveland Irrigation Co.
43 Metropolitan Water District of Salt Lake County
44 Salt Lake County WCD
45 Uintah WCD
46 Utah Power & Light

Wyoming

47 Bridger Valley WCD
48 Brinegar Sheep Company
49 Eden Valley Irrigation and Drainage District
50 Lyman, Town of
51 Mountain View, Town of
52 Wyoming, State of

APPENDIX V

COMMENTS FROM THE DEPARTMENT OF THE INTERIOR

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

MAY 8 1989

Mr. James Duffus III
Associate Director
Resources, Community, and
Economic Development Division
U. S. General Accounting Office
441 G Street, N.W.
Washington, DC 20548

Dear Mr. Duffus:

This letter responds to your April 11, 1989, letter regarding the General Accounting Office (GAO) proposed draft report entitled, "FEDERAL ELECTRIC POWER: Information Concerning the Colorado River Storage Project (CRSP)." In addition to the general comments, technical comments with references to passages of the report are also included as Enclosure 1.

In discussing the effects of the enlargement of the Diamond Fork powerplant to provide commercial power in addition to project use power, the report uses the "project use only" powerplant as a basis for comparison of alternatives (pages 34-36). This results in a somewhat misleading conclusion that the larger powerplant designed to produce commercial power could reduce the CRSP power rate. While this is a true statement with respect to the "project use only" powerplant, it would be more correct to compare all alternatives with the current CRSP rate, i.e., without any Central Utah Project (CUP) investment. For example:

CRSP Rate without CUP: 9.92 mills/kWh

CRSP Rate with CUP:
No powerplant: 11.00 mills/kWh (approximate)
Project Use Only: 11.08 mills/kWh
Commercial Power: 10.66-11.34 mills/kWh

In summary, even if no powerplant were built, a rate increase would be necessary due to the power assistance to irrigation. Thank you for the opportunity to comment on the report.

Sincerely,

Doyle M. Frederick
Assistant Secretary
for Water and Science

Enclosure

Celebrating the United States Constitution

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