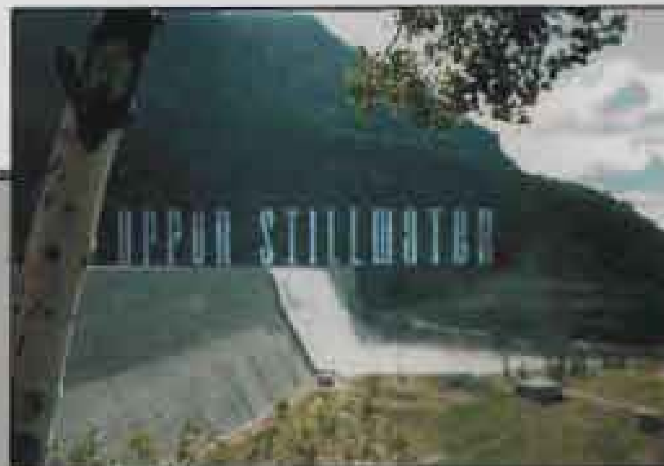
POWER APPENDIX

Central Utah Project Completion Program

Supplement to the 1988 Definite Plan Report for the Bonneville Unit



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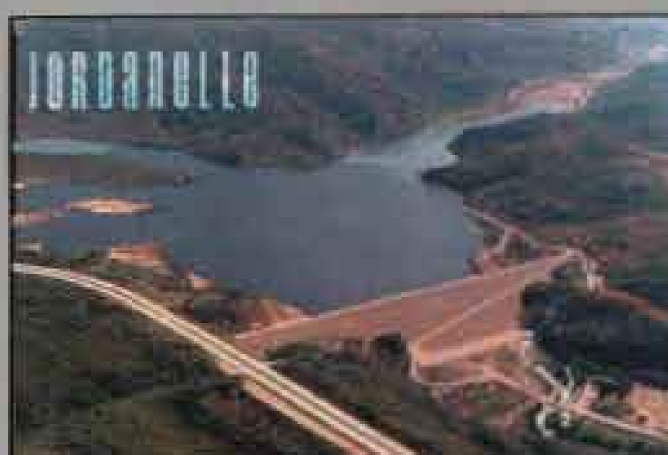

UTAH RECLAMATION MITIGATION AND CONSERVATION COMMISSION

SUPPLEMENT TO THE BONNEVILLE UNIT DEFINITE PLAN REPORT

POWER APPENDIX

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Chapter 1

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UTAH RECLAMATION MITIGATION AND CONSERVATION COMMISSION

This Power Appendix provides supporting data for the 2004 Supplement to the 1988 Definite Plan Report (DPR) for the Bonneville Unit. The purpose of this appendix is to describe the potential for hydroelectric power development and to provide details on the proposed powerplants. In addition, the appendix describes Bonneville Unit requirements for energy and power under the current project plan.

Under the current Bonneville Unit plan, a total of 50 megawatts (MW) of installed project generating capacity would be developed at two powerplants – Sixth Water and Upper Diamond Fork, both located in the Diamond Fork drainage. The Western Area Power Administration (Western) has committed to initiate a process whereby it would market project power generated at these two powerplants. A powerplant of 12 MW installed capacity is being considered for construction at Jordanelle Dam through non-federal financing under a lease of power privilege to the Central Utah Water Conservancy District (District) and Heber Light and Power (Heber L&P) pending final approval by the U.S. Department of Interior (DOI) and a decision by the lessees to proceed. Leases of power privilege are authorized under the Town Sites and Power Development Act of 1906 and the Reclamation Project Act of 1939. The Jordanelle Powerplant would not be a federal facility and, thus would not be part of the Bonneville Unit. However, lease payments would be received by the United States under the lease of power privilege, for deposit in the Upper Colorado River Basin Fund (see Section 5 of the 1956 Colorado River Storage Project Act), and would be applied towards power repayment on the Central Utah Project.

At the present time, the Bureau of Reclamation (Reclamation) has reserved 18 MW of Colorado River Storage Project (CRSP) capacity for authorized Bonneville Unit purposes. As shown in Table 1-1 and in Chapter 6 (Table 6-1), it is now estimated that approximately 15 MW of capacity will be needed under the current project plan. The District will enter into contracts with Western for the delivery of CRSP power as the project facilities are completed and Western will make arrangements for the wheeling of this energy to the project facilities. In addition, Western is generally responsible for federally owned switchyard and transmission line construction.

HISTORY OF POTENTIAL POWER DEVELOPMENT ON BONNEVILLE UNIT FACILITIES

The history of power development plans on the Bonneville Unit began with the project power described in the 1964 DPR for the Bonneville Unit. At that time it was envisioned that 133.5 MW of hydroelectric capacity would be developed, generating 319.5 million kilowatt hours (kWh) of energy in the Diamond Fork drainage. In the 1988 DPR for the Bonneville Unit the project plan included an 18.0 MW powerplant at Last Chance that would generate 27.2 million kWh of energy and 50.5 MW of capacity developed through financing by non-federal entities. Under the current project plan, 50 MW of hydroelectric capacity would be developed that would generate about 165.1 million kWh of electricity annually.

The need for CRSP power on the Bonneville Unit has varied over the past 40 years as the authorization for the project has been amended, the project plan has changed and project facilities have been completed. The current project plan is described in the 2004 Supplement to the 1988 DPR and in the 2004 Utah Lake Drainage Basin Water Delivery System (ULS System) FEIS. Table 1-1 shows the change in project power generation and CRSP power requirements from 1964 to the present.

TABLE 1-1 Bonneville Unit Historical Change in Power Generation And Requirements for Pumping Energy			
	1964 DPR	**1988 DPR**	**2004 DPR**
Powerplants			
Installed Capacity (MW)	133.5 MW	18.0 MW	50.0 MW
Annual Energy Generated	319,500,000 kWh	27,200,000 kWh	165,143,094 kWh
Non-Federal Power	0	50.5 MW	12 MW
Pumping Requirements			
Power (MW)	9.6 MW	18.0 MW	15.0 MW
Energy (kilowatt-hours)	27,200,000 kWh	23,530,000 kWh	17,186,000 kWh

Since authorization of the Bonneville Unit, power was an authorized project purpose. However, the Central Utah Project Completion Act (CUPCA), which was enacted in 1992, did not authorize the expenditure of funds to study or develop project power, thereby limiting the development of project power by a Federal entity.

In the 1980's, joint ventures between the Federal and private sector were explored by Reclamation for developing powerplants on the Diamond Fork System. In 1994, the DOI initiated a process to grant a "lease of power" privilege to non-federal entities to develop power in the Diamond Fork System. Through a competitive process DOI selected the District and the Strawberry Water Users Association (SWUA), as joint applicants, to be the potential non-federal lessees who were to plan and develop power in the Diamond Fork System. The District and SWUA were required to complete their planning and contracts within five years after being selected. When they failed to do so, DOI terminated the lease of power privilege process in 2001.

On December 19, 2002, Public Law 107-366 was enacted which amended CUPCA, and clearly authorized the Secretary of the Interior to utilize unexpended budget authority to develop project power. In accordance with this authorization, the current project plan was modified to include the development of project power. Other factors that guided the proposed development of power in the Diamond Fork drainage are the requirements set forth under Federal law for power generation on Federal facilities; and the authority under CRSP, as amended, to provide power for use on participating projects.

AUTHORITY FOR BONNEVILLE UNIT REQUIREMENTS FOR CRSP ENERGY

The Colorado River Storage Project Act of April 11, 1956 (70 Statute 105) and its subsequent amendment incorporated the concept of multipurpose water resource project development.

Project purposes authorized by the Act include not only irrigation and hydropower generation but also municipal and industrial water use, flood control, fish and wildlife mitigation and enhancement, water quality improvement, and recreation. Costs were allocated among these various uses, with hydroelectric power being allocated both its share of the costs, as well as a major portion of the amount allocated to irrigation above the irrigator's ability to pay.

The Financial and Economic (F&E) Appendix that is included as an Appendix to the 2004 Supplement to the 1988 DPR provides a cost allocation based on the Proposed Action of the ULS System FEIS (September 2004). After construction of the ULS System is completed, the DOI will prepare a final cost allocation report to incorporate any changes in the final plan and costs. The F&E Appendix allocates the current estimated project costs to each authorized project purpose. Pursuant to Section 211 of CUPCA, the "Use of Facility" method for cost allocation was used, as recommended by the Inspector General in his letter of January 26, 1994. Under this method, specific costs identified with a particular project purpose are allocated to that purpose, assigned joint costs are allocated to their project purposes, and the remaining joint costs then appropriately allocated. Additional information pertaining to the cost allocation and the allocation method described are located in the F&E Appendix to the 2004 Supplement to the 1988 Definite Plan Report for the Bonneville Unit.

Bonneville Unit Planned Activities Requiring CRSP Energy

By law, capacity from the CRSP is reserved for participating projects (e.g. the Bonneville Unit of the Central Utah Project), before marketing the balance of the long-term firm capacity. This Power Appendix estimates that the amount of energy needed for project purposes under the Bonneville Unit is about 15 MW. See Chapter 6 for details on the power needs under the current project plan.

BACKGROUND/HISTORY OF BONNEVILLE UNIT LEASE OF POWER PRIVILEGE

Lease of Power Privilege Requirements

As stated previously, the general authority for lease of power privilege under Reclamation law includes, among other laws, the Town Sites and Power Development Act of 1906 and the Reclamation Project Act of 1939. Under these Acts a lease of power privilege may be granted to qualifying entities. A lease of power privilege is an alternative to Federal hydroelectric power development. A lease of power privilege grants to a non-Federal entity the right to utilize, consistent with the Bonneville Unit purposes, water power head or storage at and/or in conjunction with Bonneville Unit for non-Federal electric power generation and sale by the entity. Leases of power privilege have terms not to exceed 40 years.

The DOI is the lead Federal agency for ensuring compliance with the National Environmental Policy Act (NEPA) of any lease of power privilege that may pertain to the Bonneville Unit of the Central Utah Project. Leases of power privilege may be issued only when the DOI determines that the affected hydroelectric power sites are environmentally acceptable.

Any lease of power privilege at a particular site on Bonneville Unit facilities must accommodate existing contractual commitments related to operation and maintenance of such existing facilities. The lessee (i.e. successful proposing entity) would be required to enter into a contract with the District to coordinate operation and maintenance of any proposed hydropower development with existing Federal features.

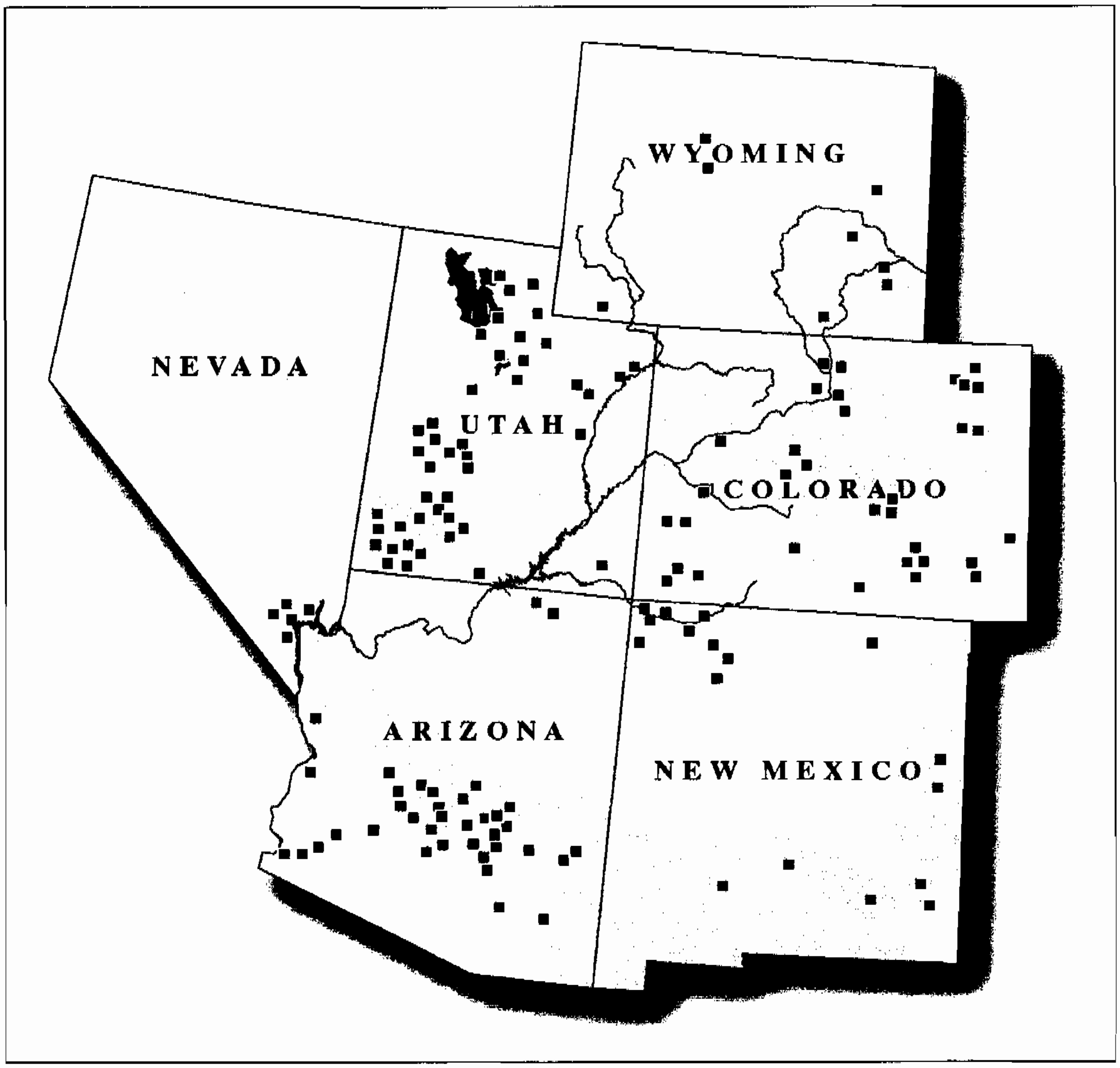
Western would have the first opportunity to purchase and/or market the power that would be generated under any lease of power privilege. Under this process, Western would either purchase and market the power as Salt Lake City Area – Integrated Projects (SLCA-IP) power or market the power independently by first offering it to preference entities and secondly to non-preference entities. Figure 1-1 is a map of the six western states of the United States where Western markets power from the SLCA/IP.

All costs incurred by the United States related to development and operation and maintenance under a lease of power privilege, including NEPA compliance and development of the lease of power privilege would be the expense of the lessee. In addition, the lessee would be required to make annual payments to the United States for the use of a Government facility. This amount will be determined depending on the economic capability of the proposed hydropower development. Such annual payments to the United States would be deposited as a credit to the Upper Colorado River Basin Fund.

Jordanelle Powerplant - Lease of Power Privilege

NEPA compliance for Jordanelle Lease of Power is presently underway and the District and Heber Light & Power (Heber L&P) may be granted a lease of power privilege from the DOI for the development of hydroelectric power at Jordanelle Dam. This lease of power is in response to the Notice of Intent (NOI) to contract for hydroelectric power development at Jordanelle Dam published by the DOI in the federal register, Volume 64, No. 137 Friday, July 2, 1999. The District and Heber L&P, with the aid of a consulting firm, completed a report entitled "The Development of Hydroelectric Power at Jordanelle Dam", January 7, 2000 for submission to the DOI with development plans and a financial analysis of developing hydroelectric power at Jordanelle Dam. The application is waiting approval following completion of NEPA compliance. Power generated at Jordanelle under the Lease of Power Privilege would be marketed by Heber L&P pursuant to the requirements of federal law.

Figure 1-1
The SLCA/IP Markets Power to Approximately 180 Utilities, Mostly in Six Western States



Diamond Fork Drainage - Lease of Power Privilege

The process for non-federal development of hydroelectric power in the Diamond Fork area was first established through a Federal Register Notice published December 19, 1994. The Federal Register Notice announced DOI's intent to issue a lease of power privilege in the Diamond Fork area of Central Utah.

The Federal Register Notice presented background information, proposal content, guidelines, information concerning the selection of a non-federal entity to develop hydroelectric power in the Diamond Fork area, and power purchasing and/or marketing considerations. The Federal Register Notice established a deadline for a potential lessee to enter into a lease with the United States within 5 years after notification of the selection of a potential lessee.

On May 1, 1995, two proposals were received in response to the Federal Register Notice that specifically focused on the Diamond Fork System. One proposal was submitted by the Western States Power Corporation and another through a joint partnership between SWUA and the District. The proposals were reviewed, and on May 1, 1996, DOI selected SWUA and the District as the successful potential joint lessee for the Diamond Fork System lease of power privilege. This notification established the deadline for entering into a lease with the United States as May 1, 2001.

Since the deadline for entering into a lease passed and a lease was not negotiated and executed, the DOI terminated this lease of power privilege process for the Diamond Fork System.

AUTHORIZATION OF FUNDING FOR POWER DEVELOPMENT ON THE BONNEVILLE UNIT

On December 19, 2002, Public Law 107-366 was enacted which amended CUPCA, and clearly authorized the Secretary of the Interior to utilize unexpended budget authority to develop project power. Subsequent planning on the Utah Lake Drainage Basin Water Delivery System (ULS System) has formulated a plan to include two powerplants in the Diamond Fork drainage. One powerplant of 45 MW capacity would be located at the Sixth Water Flow Control Structure situated between the Sixth Water Aqueduct and the Tanner Ridge Tunnel. The second powerplant would be of 5 MW capacity and located at the Upper Diamond Fork Flow Control structure situated between the Tanner Ridge Tunnel and the Upper Diamond Fork Pipeline. These powerplants are discussed in the later chapters of this Power Appendix.

LIMITATIONS ON HYDROPOWER OPERATIONS

Pursuant to Section 208 of CUPCA, power generation facilities associated with the Central Utah Project and other features authorized in CUPCA shall be operated and developed in accordance with the Act of April 11, 1956 (70 Stat. 109; 43 U.S.C. 620f). In addition, CUPCA indicates that the use of water diverted out of the Colorado River Basin for power purposes shall only be incidental to the delivery of water for other authorized project purposes, and the diversion of water out of the Colorado River Basin exclusively for power purposes is prohibited.

POWER MARKETING - WESTERN AREA POWER ADMINISTRATION

Western Area Power Administration would purchase and market the project power that would be generated by the project (e.g. Sixth Water and Upper Diamond Fork).

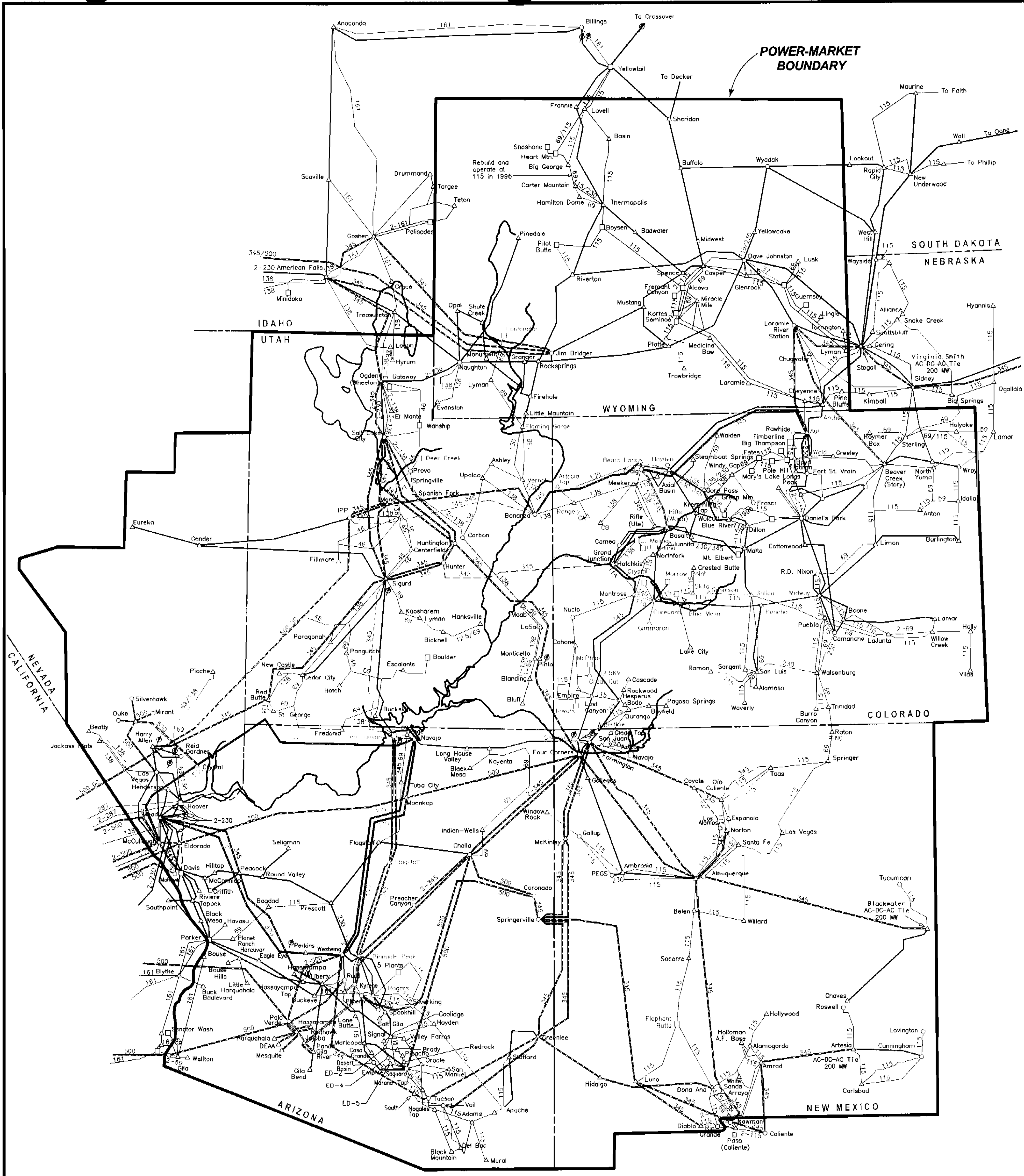
Western has committed to initiate a process whereby it would evaluate its options to market the power from the project. Options include: (1) integrating the power into the SLCA/IP and delivering it to existing firm-power customers, (2) marketing power to a subset of the SLCA/IP firm-power customers who are interested in receiving additional hydropower from Western, (3) allocating the power to existing and/or new firm-power preference customers separately from the SLCA/IP, (4) marketing the power to Federal facilities and other preference customers who have a requirement or interest in receiving renewable resources, (5) marketing the power to preference entities using some combination of short-and/or long-term power sales contracts, or (6) other options that might develop during the evaluation process. Revenues from the sale of energy from the ULS System Power Plants would be paid by Western to the Bureau of Reclamation for credit in the Colorado River Upper Basin Fund and to the District for OM&R costs per Section 9 (c) of the 1939 Act.

Western will determine if and how project power would be marketed by consulting with firm-power customers and other interested parties.

WESTERN'S TRANSMISSION SYSTEM FOR ELECTRICAL POWER

The CRSP transmission system has approximately 2,400 miles of transmission lines that are used to deliver SLCA/IP power to firm-power customers located in Arizona, Colorado, New Mexico, Utah and Wyoming. The CRSP transmission system is contained in the WALC and WACM control areas and is operated and maintained by Western offices in Phoenix, Arizona and Loveland, Colorado respectively. The two control areas are interconnected with other control areas within the Western Electric Coordinating Council (WECC), enabling Western to buy, sell, and exchange power with a large number of public and investor-owned utilities in the western United States.

The proposed ULS power plants are located within the PacifiCorp control area in Utah. Western has an existing contract with PacifiCorp to deliver SLCA/IP and other Federal hydropower to firm-power customers located in Utah and eastern Nevada. Use of the PacifiCorp contract to deliver power from the ULS power plants is a possibility and would depend upon how and to whom Western decides to market the power. If the existing PacifiCorp wheeling contract was not able to be used, it would be necessary for Western to negotiate a separate transmission agreement for delivery of project power to customers.



EXPLANATION

- △ Substation
- ○ Steam power plant
- □ Hydro power plant
- SLCA facilities
- Joint SLCA/non-federal facilities
- Federal facilities
- Joint federal/non-federal facilities
- Investor-owned facilities
- Public-non federal facilities
- Under construction or committed
- 345KV and above
- 230KV
- 161KV and below
- ø Phase shifter

SLCIP POWERPLANTS

NAME	NAMEPLATE CAPACITY (MW)
Glen Canyon (CRSP)	1356
Flaming Gorge (CRSP)	150
Morrow Point (CRSP)	192
Blue Mesa (CRSP)	96
Fontenelle (CRSP)	13
Crystal (CRSP)	28
Lower Molina (Collbran)	5
Upper Molina (Collbran)	9
Elephant Butte (Rio Grande)	24
McPhee (Dolores)	1
Towaoc (Dolores)	11
Subtotal	**1884**
ASSOCIATED POWERPLANTS	
Deer Creek (Provo River)	5.3
Falcon (Falcon)	31.5
Amistad (Amistad)	66
Subtotal	**103**
TOTAL	**1987**

Source: United States Department of Energy, Western Area Power Administration, Salt Lake City Area Office, July 2004.

Map 1-1

Salt Lake City Area Integrated Projects Interconnected Transmission Systems

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Chapter 2

Included in the Bonneville Unit's Utah Lake Drainage Basin Water Delivery System (ULS system) are two proposed hydroelectric powerplants to be located in Diamond Fork Canyon. The purpose of these power plants would be to generate electrical energy and to mitigate the effects of high-pressure buildup in the pipeline through the steep canyon descent. The powerplant site locations were chosen to take advantage of existing facilities and to minimize impacts to the environment. The chosen site locations are the terminus of the Sixth Water Aqueduct and the terminus of the Upper Diamond Fork Pipeline both existing facilities of the Diamond Fork System.

This chapter, the following chapters, and Attachment A document the methodology and results of evaluating hydroelectric potential in the Diamond Fork drainage. Map 2-1 on the next page shows the location of the proposed power plants and transmission lines.

SIXTH WATER POWERPLANT

The proposed Sixth Water hydroelectric powerplant would be located in the Diamond Fork drainage basin at the downstream end of the Sixth Water Aqueduct. The powerplant would be adjacent to the existing Sixth Water Flow Control Structure. The Sixth Water Aqueduct receives water from the Strawberry Reservoir through Syar tunnel and discharges the water into Tanner Ridge Tunnel and when necessary into Sixth Water Creek. The length of the water conveyance system from Strawberry Reservoir is approximately 41,281 ft long and includes the Syar Tunnel and Inlet Portal, and the Sixth Water pipeline and shaft.

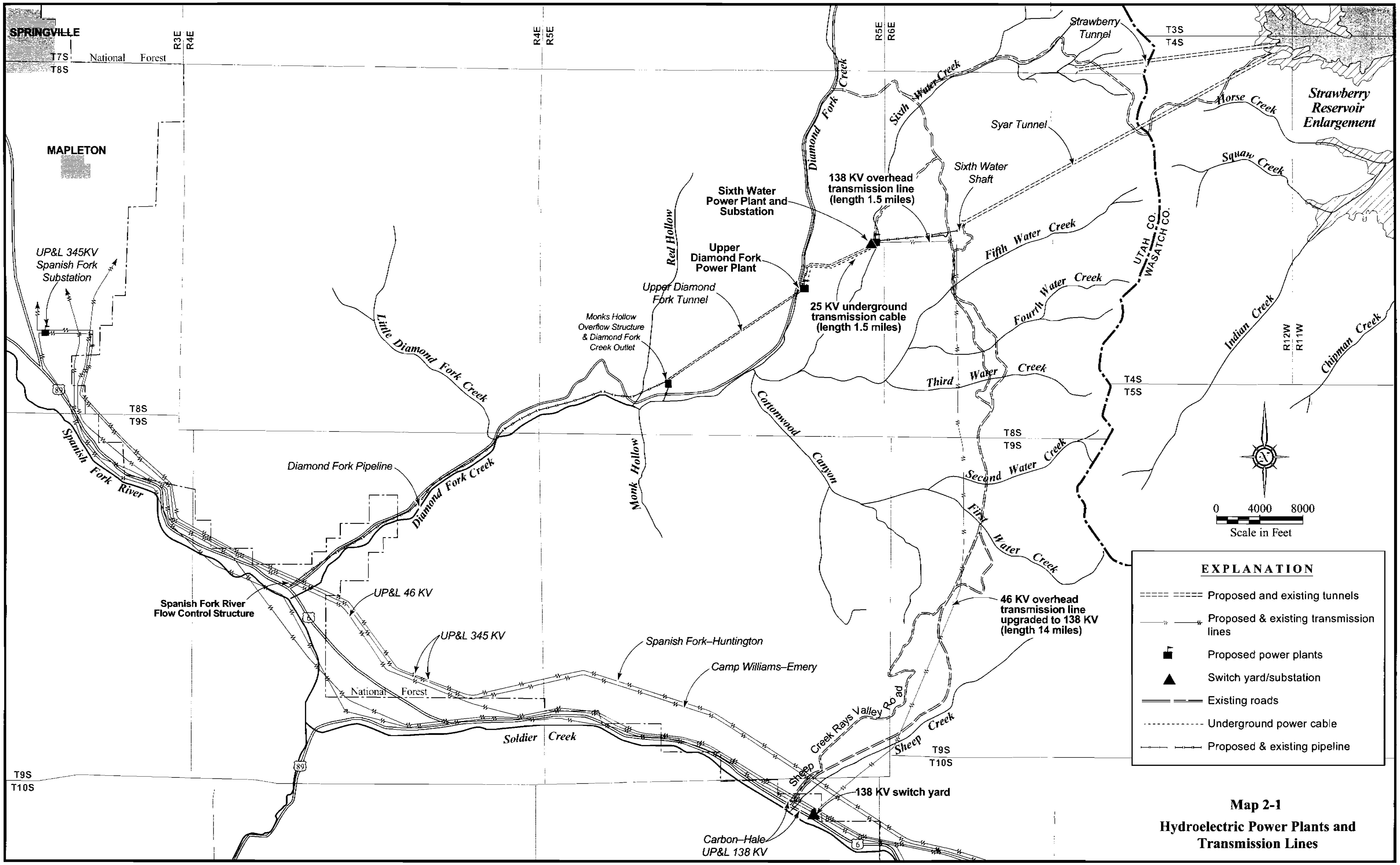
UPPER DIAMOND FORK POWERPLANT

The proposed Upper Diamond Fork hydroelectric powerplant would be located in the upper reach of the Diamond Fork Canyon. The plant would be located adjacent to the Upper Diamond Fork Flow Control Structure located at the downstream end of the Upper Diamond Fork Pipeline. The water conveyance system begins immediately downstream of the Sixth Water Aqueduct and includes the Tanner Ridge Tunnel and the Upper Diamond Fork Pipeline. The length of the water conveyance system between the vertical shaft adjacent to the Sixth Water Flow Control structure and the proposed Upper Diamond Fork powerplant is approximately 11,183 feet in length.

Study Approach and Methodology

The study of the technical feasibility and economic viability of the proposed hydroelectric developments was completed at a feasibility level and included the following steps:

- Selection of powerplant location and generating equipment;
- Inventory of existing transmission lines and substations in the project area;
- Selection of transmission line route, voltage, and interconnection requirements; and
- Optimization of installed capacity.



Map 2-1
Hydroelectric Power Plants and Transmission Lines

In addition, it was necessary to make assumptions regarding the water supply and anticipated operations of the powerplants to complete the analysis. The assumptions were applied to both powerplants and are detailed in the following sections of this Chapter.

Governing Assumptions

Flow releases through the aqueducts and pipelines of the Bonneville Unit's Diamond Fork System and the ULS System would be dictated by municipal and industrial delivery patterns, while the electric energy generated at the proposed powerplants will be incidental to the foregoing purposes.

The proposed powerplants would be located adjacent to the pressure reducing valves. In addition, the turbine(s) at each powerplant would be linked to the associated flow control mechanisms of the pressure reducing valves in order to provide an uninterrupted flow in the water conveyance system (pipeline or aqueduct), should the plants be out of service. Depending on the installed capacity, some plants may not have sufficient hydraulic capacity to pass the maximum flow releases and the remaining flow would be passed through the flow control valve(s). Furthermore, the proximity and linkage between the turbine(s) of each powerplant and the flow control valve(s) would minimize the effects of pressure rise in the water conveyance system.

Given the relatively small capacity of the proposed hydroelectric generation facilities, it has been assumed that:

- The plants' energy would always be dispatched;
- All the net energy generation would be delivered to the local power grid; and
- There would be no constraints in the interconnections to the electrical grid.

Powerhouse Site Selection

Site visits were conducted to confirm the selected locations with the site selection for the Sixth Water and Upper Diamond Fork powerplants being governed by the location of the following flow control structures:

- Sixth Water Flow Control Structure (existing); and
- Upper Diamond Fork Flow Control Structure (existing).

Selection of Generating Equipment

The selection of generating equipment was carried out utilizing estimated flow releases from Strawberry Reservoir for the simulation period from 1950 to 1999. These values were obtained from the Water Supply Appendix and are summarized in Table 2-1. Although water is currently discharged to Sixth Water Creek, the available flows for generating electricity at both generating sites would be the same once the Diamond Fork System is online.

Table 2-1
Estimated Flows Available for Generation
Sixth Water and Upper Diamond Fork Power Stations
(cfs)

Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Ave
1950	89.4	40.9	42.1	53.6	32.6	31.5	42.5	116.4	436.0	427.8	510.2	389.4	184.4
1951	50.4	38.6	38.1	37.2	34.0	36.1	42.5	105.7	441.2	512.5	417.0	307.7	171.8
1952	50.6	40.7	41.0	33.5	33.0	30.1	42.5	101.8	248.7	422.7	365.7	340.4	145.9
1953	148.1	24.8	29.6	25.0	30.2	29.3	94.0	137.0	451.7	484.1	397.7	291.6	178.6
1954	44.9	39.9	43.5	31.9	41.5	36.0	113.6	273.0	458.4	439.6	454.0	204.6	181.8
1955	53.3	45.3	46.8	40.5	42.9	46.1	160.1	258.6	481.9	536.9	393.7	253.9	196.7
1956	56.2	50.4	46.8	40.5	45.9	38.0	64.6	303.5	559.1	487.8	451.2	265.9	200.8
1957	54.5	47.0	46.8	40.5	39.2	42.9	111.9	176.8	260.5	551.0	477.3	326.8	181.3
1958	50.8	42.0	45.1	40.5	38.8	42.9	48.7	176.8	496.3	519.3	499.4	253.7	187.8
1959	54.8	45.3	45.1	40.5	42.4	43.5	161.6	439.9	558.0	402.6	347.2	209.2	199.2
1960	56.2	48.7	50.0	42.1	40.4	36.6	143.2	400.3	560.7	471.2	420.5	203.0	206.1
1961	55.1	47.0	50.0	42.1	46.0	59.0	177.5	459.7	540.0	382.1	274.8	200.5	194.5
1962	57.4	48.7	48.4	43.7	42.4	46.1	45.3	203.7	474.3	487.3	537.2	272.6	192.3
1963	50.9	47.0	48.4	40.5	31.6	42.9	166.8	313.1	333.5	553.8	489.3	244.3	196.8
1964	81.3	69.5	119.5	116.7	75.8	66.7	153.9	177.7	272.3	649.4	512.5	370.7	222.2
1965	128.3	65.4	71.5	72.6	79.8	81.5	53.4	176.8	274.9	433.4	407.8	297.6	178.6
1966	135.5	100.0	46.1	52.4	74.3	39.6	106.0	315.6	570.5	455.0	462.8	279.5	219.8
1967	101.2	59.1	92.9	60.5	49.8	46.9	148.1	200.7	220.4	557.7	532.8	391.8	205.1
1968	125.9	78.9	74.2	71.7	60.5	77.7	97.5	177.8	322.3	528.0	387.7	355.9	196.5
1969	115.6	92.3	113.4	36.9	56.3	22.6	42.5	104.8	321.2	453.5	522.2	345.6	185.6
1970	113.8	41.8	57.9	67.7	67.9	77.0	151.7	163.2	325.7	488.4	555.2	295.5	200.5
1971	87.9	37.4	82.5	66.7	56.6	47.6	58.7	218.0	390.8	558.3	549.4	251.7	200.5
1972	112.3	38.6	73.2	79.4	77.7	35.3	91.5	379.8	440.3	496.5	464.7	251.7	211.7
1973	123.2	98.1	84.5	75.5	70.7	71.1	42.5	101.8	307.0	497.6	504.5	263.0	186.6
1974	123.0	92.5	72.2	77.8	81.8	65.8	60.7	136.8	474.9	477.2	521.6	274.8	204.9
1975	116.6	110.4	80.3	66.5	68.4	66.0	133.7	176.8	158.7	526.4	571.3	366.5	203.5
1976	119.3	40.8	37.4	55.0	56.1	64.6	108.1	331.2	566.7	559.6	525.7	300.2	230.4
1977	107.3	65.1	83.8	77.4	43.4	46.4	162.2	377.3	565.4	497.6	499.2	287.4	234.4
1978	189.0	179.6	179.0	147.2	134.1	76.9	83.7	176.8	456.9	607.5	562.9	277.6	255.9
1979	178.9	176.4	167.3	144.2	137.6	134.7	80.2	182.6	517.3	576.7	509.9	267.1	256.1
1980	221.6	189.5	182.1	136.0	123.2	126.6	42.5	108.5	315.2	495.7	566.6	245.2	229.4
1981	165.6	78.4	65.1	93.6	90.4	102.6	158.2	350.5	489.6	534.6	510.2	237.0	239.7
1982	136.1	73.6	91.8	100.1	90.9	36.1	42.5	101.8	249.1	448.1	542.9	258.9	181.0
1983	60.1	41.0	40.6	38.7	39.5	22.7	42.5	180.5	330.5	353.4	395.8	182.7	144.0
1984	52.1	34.4	32.1	29.3	31.2	20.8	42.5	156.1	323.4	428.5	449.2	347.3	162.2
1985	50.4	38.8	42.8	41.1	42.7	19.8	42.5	101.8	372.9	374.0	519.1	224.7	155.9
1986	58.9	37.3	41.4	38.7	24.7	19.8	42.5	101.8	306.7	428.4	465.9	219.0	148.8
1987	54.1	70.4	38.2	35.7	36.0	36.7	128.1	316.4	513.4	429.8	459.3	331.8	204.1
1988	97.2	44.8	45.7	41.3	42.0	42.0	163.2	380.1	547.7	559.6	497.1	301.7	230.2
1989	37.8	90.4	91.7	60.6	46.2	44.7	138.9	450.4	551.3	500.5	417.0	234.0	222.0
1990	141.3	88.3	93.3	77.6	79.5	80.2	160.6	369.5	413.0	545.7	531.3	363.4	245.3
1991	107.6	80.3	104.0	103.7	55.0	56.7	181.4	298.7	285.0	560.0	574.4	285.4	224.4
1992	134.6	82.1	104.3	88.2	63.1	68.5	157.8	432.9	540.4	442.6	444.3	297.1	238.0
1993	153.6	139.3	121.3	114.4	100.2	65.3	86.7	176.8	318.4	486.8	557.3	357.2	223.1
1994	86.9	74.4	82.1	79.1	65.2	47.4	156.8	352.6	563.0	552.9	421.7	356.3	236.5
1995	91.0	90.7	90.1	84.9	76.7	61.2	88.1	176.8	204.1	367.3	523.7	283.0	178.1
1996	119.5	41.9	42.6	37.0	43.3	25.5	45.1	101.8	321.7	428.9	534.9	274.8	168.1
1997	129.1	112.3	67.8	59.8	64.3	19.8	42.5	101.8	256.3	505.9	473.1	281.5	176.2
1998	183.9	119.9	74.2	124.1	135.0	49.8	55.1	101.8	194.2	547.2	622.5	422.8	219.2
1999	98.4	42.5	43.8	64.9	36.2	34.3	114.3	101.8	320.2	530.0	526.2	308.9	185.1
Ave.	**100.2**	**70.5**	**71.0**	**65.4**	**60.3**	**51.2**	**98.4**	**226.5**	**398.0**	**491.2**	**483.1**	**289.1**	**200.4**
Max.	**221.6**	**189.5**	**182.1**	**147.2**	**137.6**	**134.7**	**181.4**	**459.7**	**570.5**	**649.4**	**622.5**	**422.8**	**256.1**
Min.	**37.8**	**24.8**	**29.6**	**25.0**	**24.7**	**19.8**	**42.5**	**101.8**	**158.7**	**353.4**	**274.8**	**182.7**	**144.0**

In addition, the following criteria gathered from experience on similar plants was utilized in the analysis.

- Minimize the number of generating units;
- Preference for Pelton type turbines to minimize pressure rise in water conveyance system in case of load rejection;
- Minimize physical size of units (higher rotational speeds);
- Maximize efficiency for head and flow operating range;
- Maximize energy production;
- Limit number of jets in vertical Pelton turbines to minimize jet interference;
- Maximize turbine head and flow operating range;
- Minimum turbinable flow:
    - Pelton turbines - 10% of unit rated flow
    - Francis turbines - 50% of unit rated flow
- Facilitate maintenance (preference to horizontal units).

Vertical axis type turbines were preferred for the Sixth Water powerplant in order to reduce the footprint of the powerhouse building given the existing space constraints at this site.

Horizontal axis type turbines were preferred for the Upper Diamond Fork powerplant due to the relatively small plant rated flow of 120 cfs and to minimize the visual impact of the powerhouse building, which would have only one floor where the turbine(s) and generator(s) would be mounted. In addition, maintenance of the generating units would be carried out using mobile cranes given the small size of the units. Therefore, no powerhouse overhead crane would be provided at this powerplant, which would result in a further reduction of the powerhouse height and associated visual impact. Furthermore, only about 25 ft of the powerhouse structure would be above grade.

Generating equipment was selected for the each powerplant based on the criteria and preferences given above, and the flows listed in Table 2-1. Details of the selected equipment are summarized in Table 2-2.

TABLE 2-2
Selected Generating Equipment

Powerplant	Turbine		Number Units	Number Transformers
	Type	Axis		
Sixth Water	Pelton – 4 to 6 jets	Vertical	1	1
Upper Diamond Fork	Pelton – 2 jets	Horizontal	1	1

ELECTRICAL TRANSMISSION FACILITIES

Inventory of Existing Transmission Lines and Substations in the Project Area

An inventory and data collection of the existing transmission lines and substations in the proximity of the project area was carried out to identify the possibility of these facilities being used to convey the power from the proposed powerplants and connect to the local electric grid. The process included a review of available maps showing existing lines and substations, a reconnaissance visit to the identified grid transmission lines and substations, and preliminary discussions with the Utah Power & Light (UP&L) electric utility, which own transmission facilities in the proximity of the project area. Table 2-3 summarizes the transmission lines identified in the project area and their potential use to convey power from the proposed powerplants.

TABLE 2-3
Summary of Transmission Lines in Project Area

Line Voltage (kV)	Owner	Reference Location	Nearest Power Station Site	Distance (Miles)	Potential Use for Power Evacuation
46	UP&L	Rays Valley Road	Sixth Water	1.5	Yes-upgrade required
46	UP&L	Highway 6 & Diamond Fork Creek	Upper Diamond Fork	12.5	Yes
138	UP&L			12.6	Yes

Selection of Transmission Line Route, Voltage, and Interconnection to the Grid

The selection of the transmission line route, voltage, and interconnection point to the grid took into account the following factors:

- Proximity of the proposed powerplants to the existing transmission lines and substations of the electric grid;
- Voltage level on existing transmission lines and substations of the electric grid;
- Environmental constraints;
- Acceptable voltage drops in the transmission lines connecting the powerplants to the electric grid:
- Limited transmission losses;
- Expected Utility interconnection requirements; and
- Cost considerations.

Some details of the transmission facilities shown above could change depending upon how the project power was marketed and after negotiations with PacifiCorp for an interconnection with its transmission system. For additional information see Chapters 3 & 4 of this Power Appendix.

Optimization of Installed Capacity

An optimization analysis of the installed capacity was carried out for each of the power plants. However, the maximum capacity of the Upper Diamond Fork power plant was limited to 5,000 kW, due to the power limitations of the power cable installed in the Tanner Ridge Tunnel.

The optimization process encompassed the following activities:

- Selection of a range of plant flows;
- Estimation of energy production;
- Estimation of energy benefits;
- Estimation of project implementation costs;
- Estimation of operation and maintenance (O&M) costs;
- Economic analysis; and
- Selection of optimum installed capacity.

As shown above, an economic analysis was conducted as part of the optimization analysis. Two methods were investigated for selecting the optimum installed capacity - the present value of net benefits (NPV) and the benefit-cost (B/C) ratio. While this methodology is adequate from a planning perspective, it should not be confused with the prescribed method of estimating benefits and of cost allocation for the Bonneville Unit of the Central Utah Project. Regulations for the economic evaluation of the Bonneville Unit were prescribed in 1994 by the United States General Accounting Office (GAO), which recommended the Use of Facilities Cost Allocation Method from the Central Valley Project of California (March, 1992). Therefore, use of the results of this economic analysis were limited to the purpose of determining the optimum installed capacity and are not valid or recommended for any other use.

The criteria used in selecting the optimum installed capacity was the maximization of the present value of the net benefits (NPV). Figures 2-1 and 2-2 graphically depict the calculated NPV's plotted against installed capacity. The highest point on the graph was selected as the optimum installed capacity. Because of the detailed nature of the optimization analysis, the entire analysis including calculations and results is located in Attachment A. Table 2-4 summarizes the selected optimum installed capacities and corresponding NPV's.

TABLE 2-4
Optimum Installed Capacity

Powerplant	Optimum Installed Capacity (kW)	Net Present Value
Sixth Water	40,000	$ 45,243,861
Upper Diamond Fork	5,000	$ 10,783,340

Annual OM&R

Annual operation, maintenance and replacement costs (OM&R) for the Sixth Water and Upper Diamond Fork Powerplants was estimated based on a comparison to the Crystal Powerplant and the Lower Molina Power Plant. Crystal Powerplant is a part of the Bureau of Reclamation's Colorado River Storage Project and Lower Molina Powerplant is a part of the Bureau of Reclamation's Collbran Project. Specific information on the OM&R for these powerplants is presented in Chapter 4 and Chapter 5 respectively. The combined OM&R at Sixth Water and Upper Diamond Fork is estimated to be approximately 13.1 mils as shown in Table 2-5

TABLE 2-5
Crystal and Lower Molina Costs As Representative Utah Lake System Power OM&R Estimates

	Sixth Water	Upper Diamond Fork	Total
Annual Generation	134,284,298	30,873,677	165,157,975
Annual OM&R	$1,850,087	$315,821	$2,165,908
Rate (mils)	13.8	10.2	13.1

It is important to note that the optimization and economic analyses were completed at the time work began on the ULS System FEIS of September 2004. As a result, an installed capacity of 45,000 kW was assumed in the interest of expediting the EIS process. Subsequently, the optimization analysis indicated the optimum capacity to be 40,000 kW as shown above. Actual installed capacity at the Sixth Water Powerplant may vary between 40,000-45,000 kW, but should not exceed the 45,000 kW plant described in the ULS System FEIS (September 2004).

Several points of clarification were raised by U.S. Bureau of Reclamation as the draft Power Appendix was nearing completion-

- How will the power be dispatched?
- Who will operate and maintain the powerplants?
- The powerplants will need Power System Stabilizers and Automatic Voltage Regulators.
- How will control of the water and power be communicated?
- Is a SCADA system required?
- Need to look at making the O&M of the powerplants practicable.
- What is the seasonal energy generation patterns from the powerplants?

These points and others will be addressed in the design and construction phase of the two powerplants.

Figure 2-1
Sixth Water Power Plant
Net Present Value vs. Installed Capacity

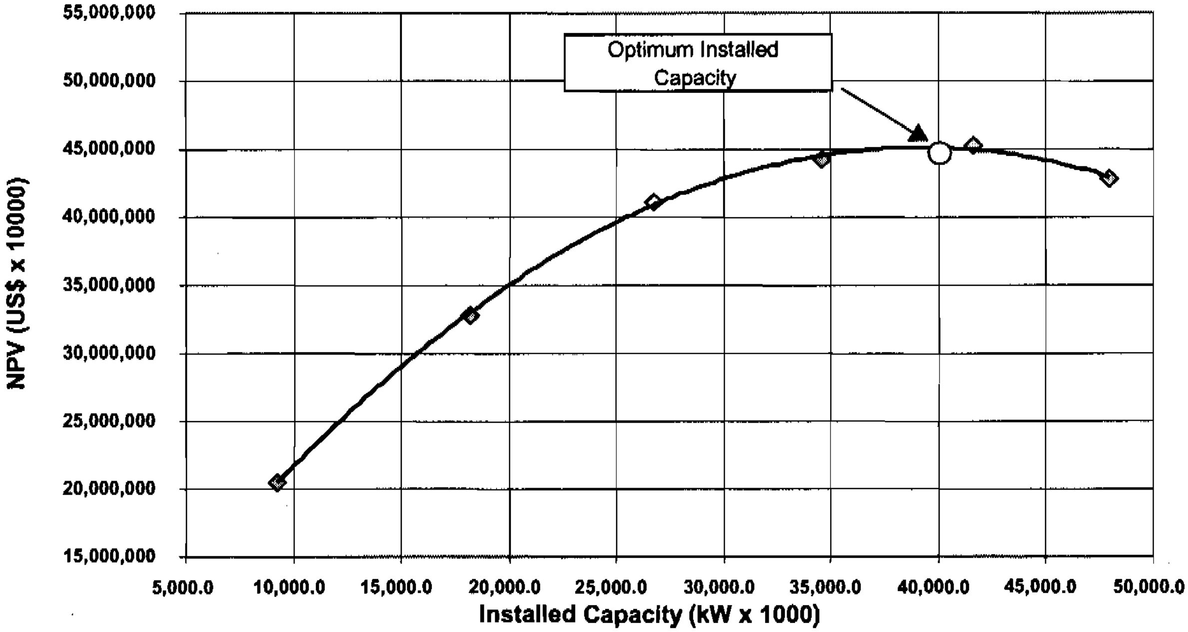
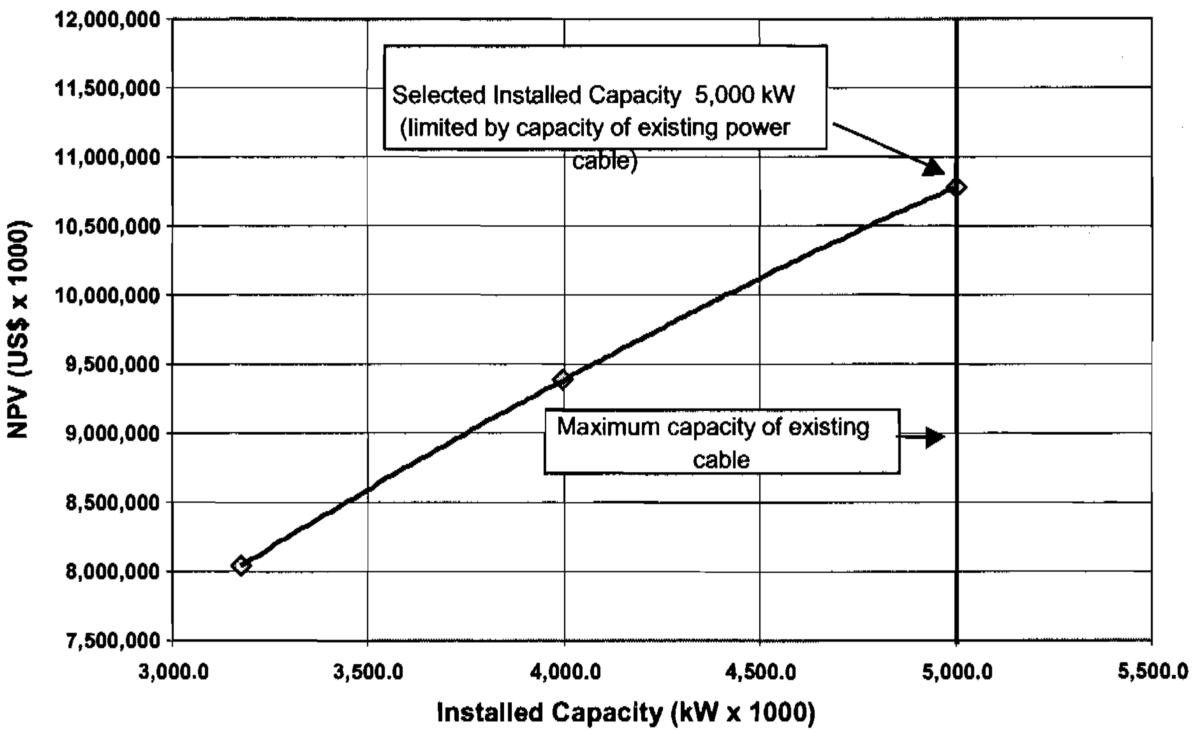


Figure 2-2
Upper Diamond Fork Power Plant
Net Present Value vs. Installed Capacity



Central Utah Project Completion Program

Chapter 3

October 2004

UTAH RECLAMATION
MITIGATION
AND CONSERVATION
COMMISSION

Chapter 3

Based on the technical and economic methodology discussed in Chapter Three, the optimum powerplant capacity at Sixth Water was determined to be 40,000 kW. Actual installed capacity of at the Sixth Water Hydroelectric Plant may vary between 40,000-45,000 kW and should not exceed the 45,000 kW used in the ULS System EIS. This chapter summarizes the equipment, physical characteristics and costs of the optimum 40,000 kW hydroelectric powerplant at Sixth Water.

SITE SELECTION

Site visits were conducted to confirm the selected location of the Sixth Water Hydroelectric Powerplant. The site selection for this plant was governed by the location of the existing Sixth Water Flow Control Structure, which is located in the Diamond Fork drainage basin at the downstream end of the Sixth Water Aqueduct. The powerplant would be adjacent to the existing Sixth Water Flow Control Structure. The Sixth Water Aqueduct receives water from the Strawberry Reservoir through Syar tunnel and discharges the water into Tanner Ridge Tunnel and when necessary into Sixth Water Creek.

LAND MANAGEMENT STATUS AND RIGHT-OF-WAY ACQUISITION

Figure 3-1 depicts the Land Management Status for the Sixth Water Transmission Line. Some of the National Forest System land that would be required has already been withdrawn by Reclamation for the Diamond Fork System. Additional National Forest System land would be withdrawn and some previously withdrawn land would be revoked, as shown on the figure. The withdrawal and revocation of National Forest System land would be achieved through the application to the Bureau of Land Management and a subsequent Public Land Order. If the land withdrawal does not occur, then a Special Use Permit would have to be obtained from the Forest Service. If the land were withdrawn before construction commences, the permits with the Forest Service would not be necessary.

CIVIL WORKS

The civil works associated with the Sixth Water Hydroelectric Powerplant would include the following structures:

- A steel bifurcation from the 7.25 ft diameter steel pipe conveying the flow to the existing flow control valves;
- A steel pipe from the bifurcation to the turbine inlet;
- A short reinforced concrete channel from the powerplant to the vertical shaft of the Tanner Ridge Tunnel; and
- Insulated office space for powerplant operators to reduce the noise from the powerplants during their generation of power.

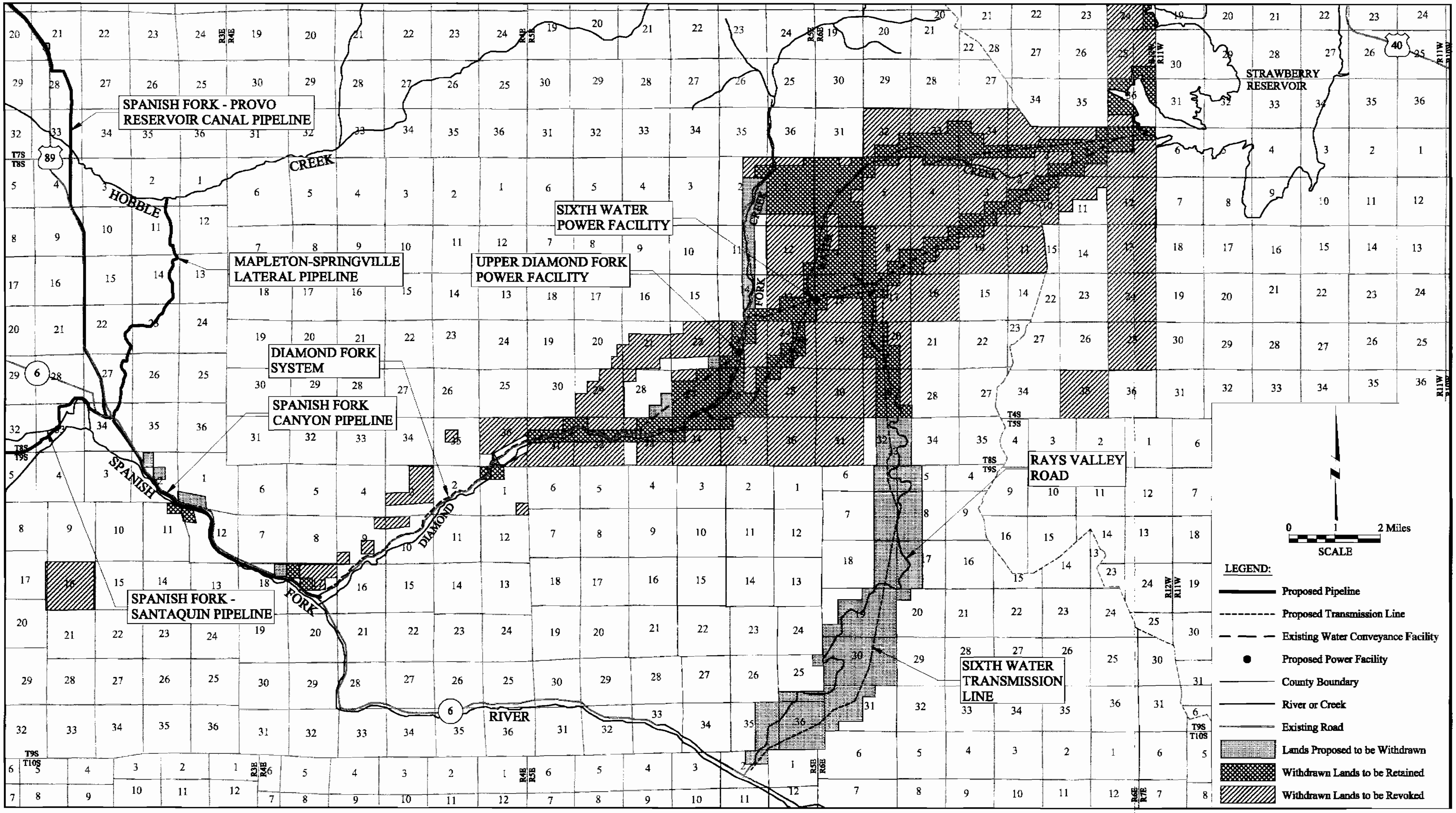


Figure 3-1
Land Management Status for the Sixth Water Transmission Line

- A surface type reinforced concrete powerplant approximately 65.5 ft wide, 72 ft long, and 76 ft high containing a vertical shaft generating unit driven by a Pelton turbine and auxiliary electrical and mechanical equipment. An overhead crane would be provided for maintenance of the generating unit; and
- A substation adjacent to the powerplant, which would contain the main power transformer, 138 kV switchgear, take-off structure for the 138 kV transmission line, and 13.8 kV disconnect switches for the 13.8 kV incoming line from the proposed Upper Diamond Fork powerplant.

A conceptual perspective of the proposed civil works is shown on Figure 3-2. Plan and cross-sectional views of the powerplant, sized for the 40,000 kW-installed capacity are shown on Figures 3-3 and 3-4, respectively. The substation plan for the Sixth Water Hydroelectric Powerplant is shown on Figure 3-5.

SELECTION OF GENERATING EQUIPMENT AND OPTIMUM INSTALLED CAPACITY

The proposed Sixth Water Powerplant would contain a single generating unit consisting of a vertical shaft, Pelton turbine and a synchronous generator directly coupled to the turbine. The turbine centerline would be set at Elevation 6,327.25 ft. A spherical valve would be provided at the inlet of the turbine distributor to permit isolation of the unit for maintenance or to shut-off the flow in case of emergency. In addition, a digital governor would be provided for frequency and load control of the generating unit. A three-phase, 13.8/138 kV step-up transformer would be connected to the generator. The powerplant would be provided with the typical mechanical and electrical auxiliary systems required for generating electricity at hydroelectric powerplants. In addition, a bridge overhead crane would be provided for maintenance of the generating unit.

As discussed in Chapter Three, an optimization analysis was performed to determine the optimal generator capacity for the powerplant. The criteria used in selecting the optimum installed capacity was the maximization of the present value of the net benefits (NPV). Figure 3-1(located in Chapter 3 of this Appendix) graphically depicts the calculated NPV's plotted against installed capacity for the proposed Sixth Water Powerplant. The highest point on the graph was selected as the optimum installed capacity for the Sixth Water Hydroelectric Powerplant. Details of the generation equipment selected for the Sixth Water Hydroelectric Powerplant are summarized in Table 3-1 located on Page 3-8 of this Chapter following the schematic drawings. The substation, that would be located near the powerplant, would contain the following electrical equipment:

- One three-phase step up transformer and 138 kV switchgear;
- Take-off structure for the 138 kV outgoing line; and
- 13.8 kV disconnect switches for the 13.8 kV incoming line from the proposed Upper Diamond Fork hydroelectric powerplant.

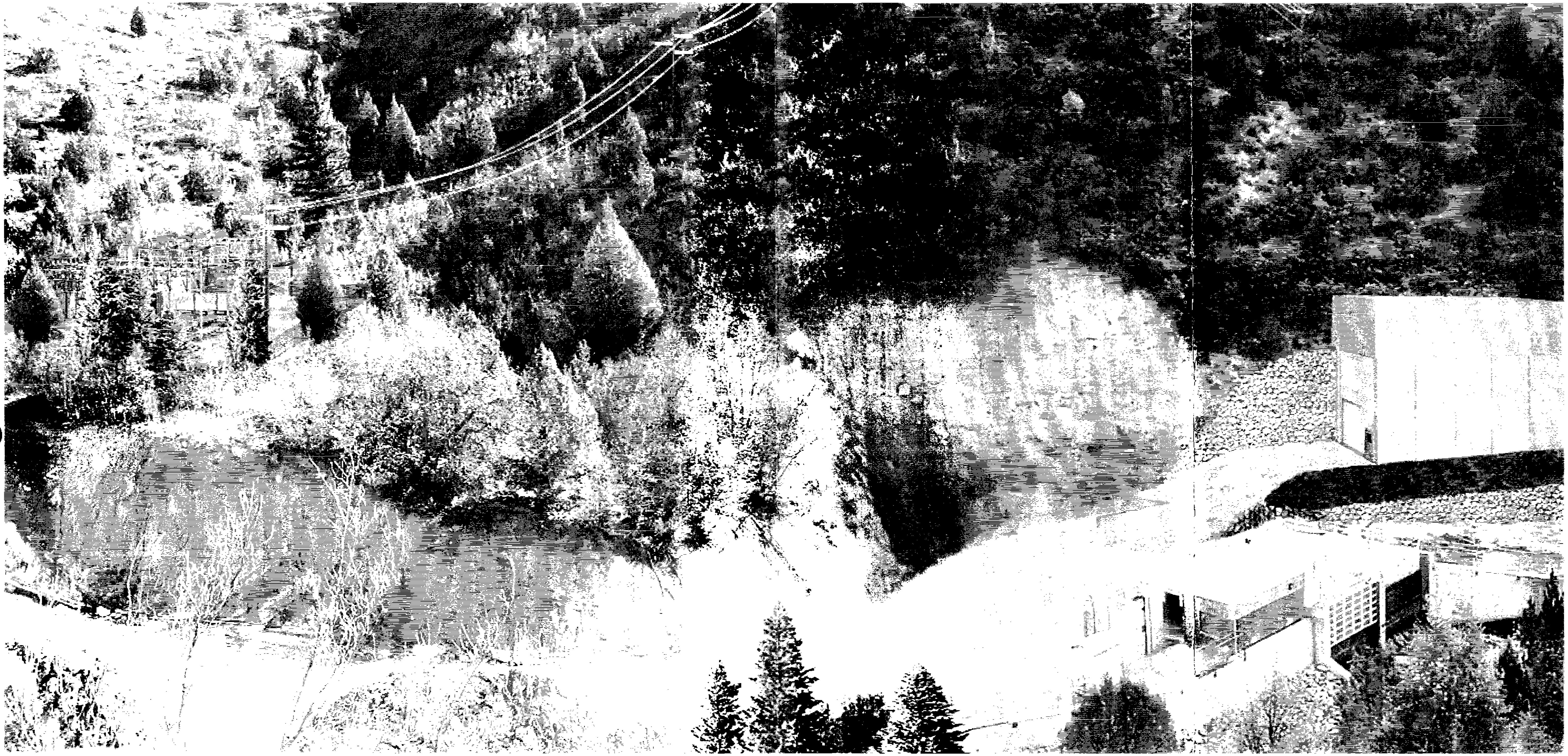


Figure 3-2
Sixth Water Hydroelectric Plant
Conceptual Perspective of the Proposed Civil Works

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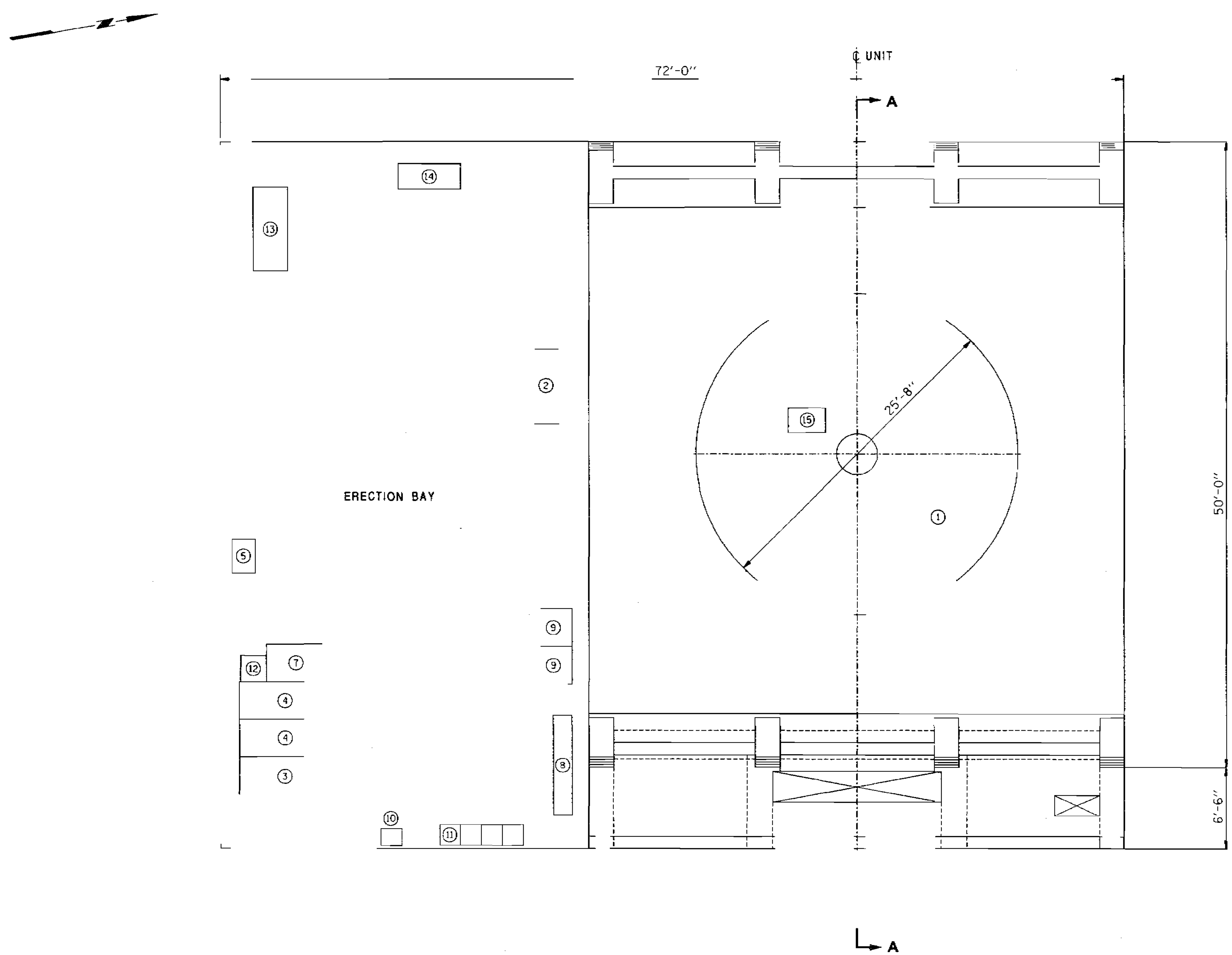

PLAN

EQUIPMENT LIST:

1. GENERATOR
2. GENERATOR CONTROL CABINET
3. PT/AVR CABINET
4. GENERATOR BREAKER
5. MAIN CIRCUIT BREAKER
6. SERVICE TRANSFORMER BREAKER
7. STATION SERVICE TRANSFORMER
8. BATTERY
9. BATTERY CHARGER/INVERTER
10. 240/120V LIGHTING PANEL & TRANSFORMER
11. MOTOR CONTROL CENTER
12. NEUTRAL GROUNDING CUBICLE
13. DIESEL GENERATOR
14. STATION AIR COMPRESSOR
15. GENERATOR BEARING
16. STATION AIR COMPRESSOR

SCALE 0 4 8 FEET
1/8" = 1'-0"

MWH

FIGURE 3-3

SIXTH WATER HYDROELECTRIC FACILITY
SCHEMATIC OF POWERPLANT PLAN

PAGE NUMBER 3-5 SKM-01

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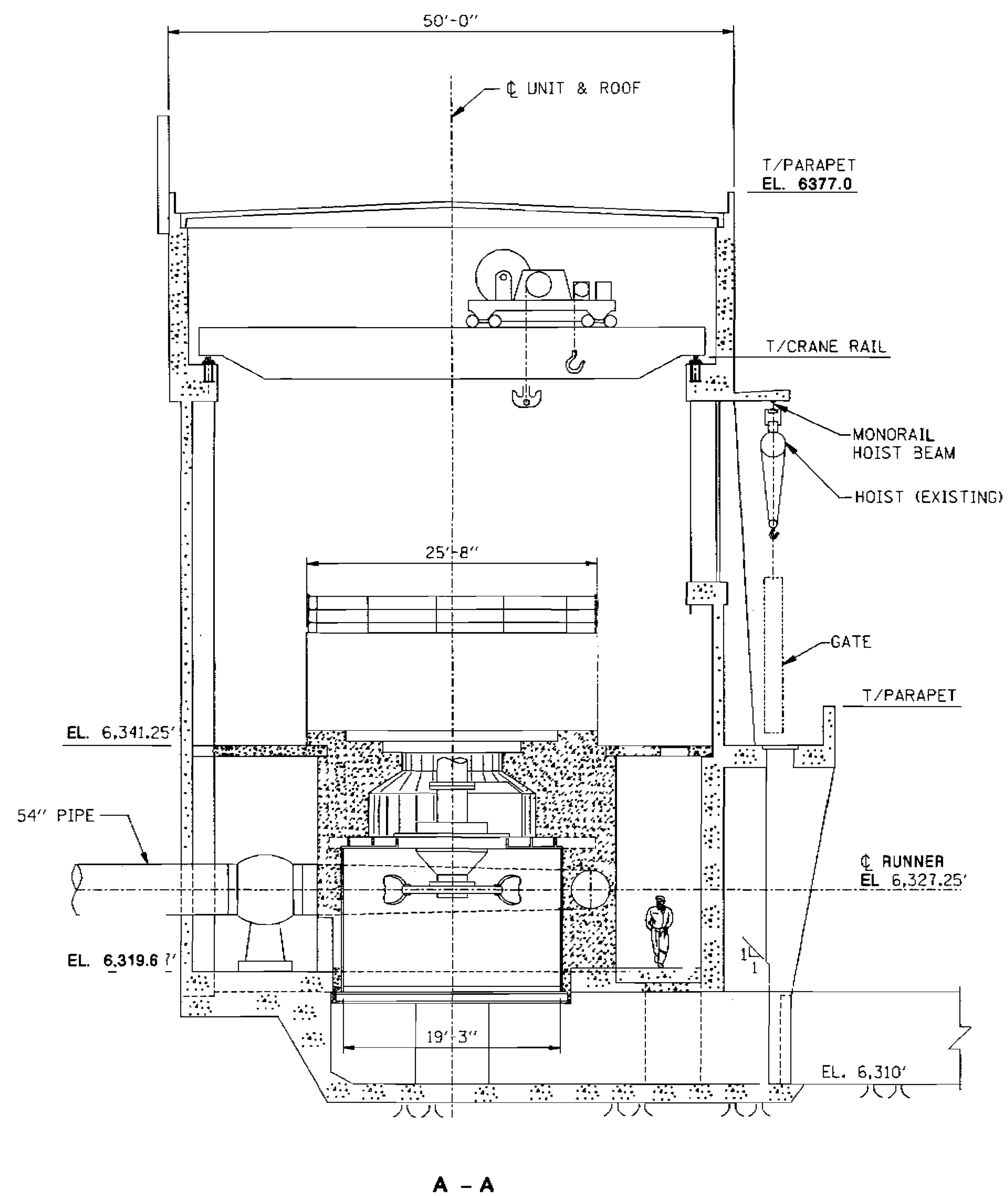

NOTES:

DIMENSION SHOWN FOR SELECTED OPTIMAL INSTALLED CAPACITY OF 40 MW (ALTERNATIVE 2).

SCALE 0 4 8 FEET
1/8" = 1'-0"

MWH

FIGURE 3-4

SIXTH WATER HYDROELECTRIC FACILITY
POWERPLANT CROSS SECTION

PAGE NUMBER 3-6 SKM-02

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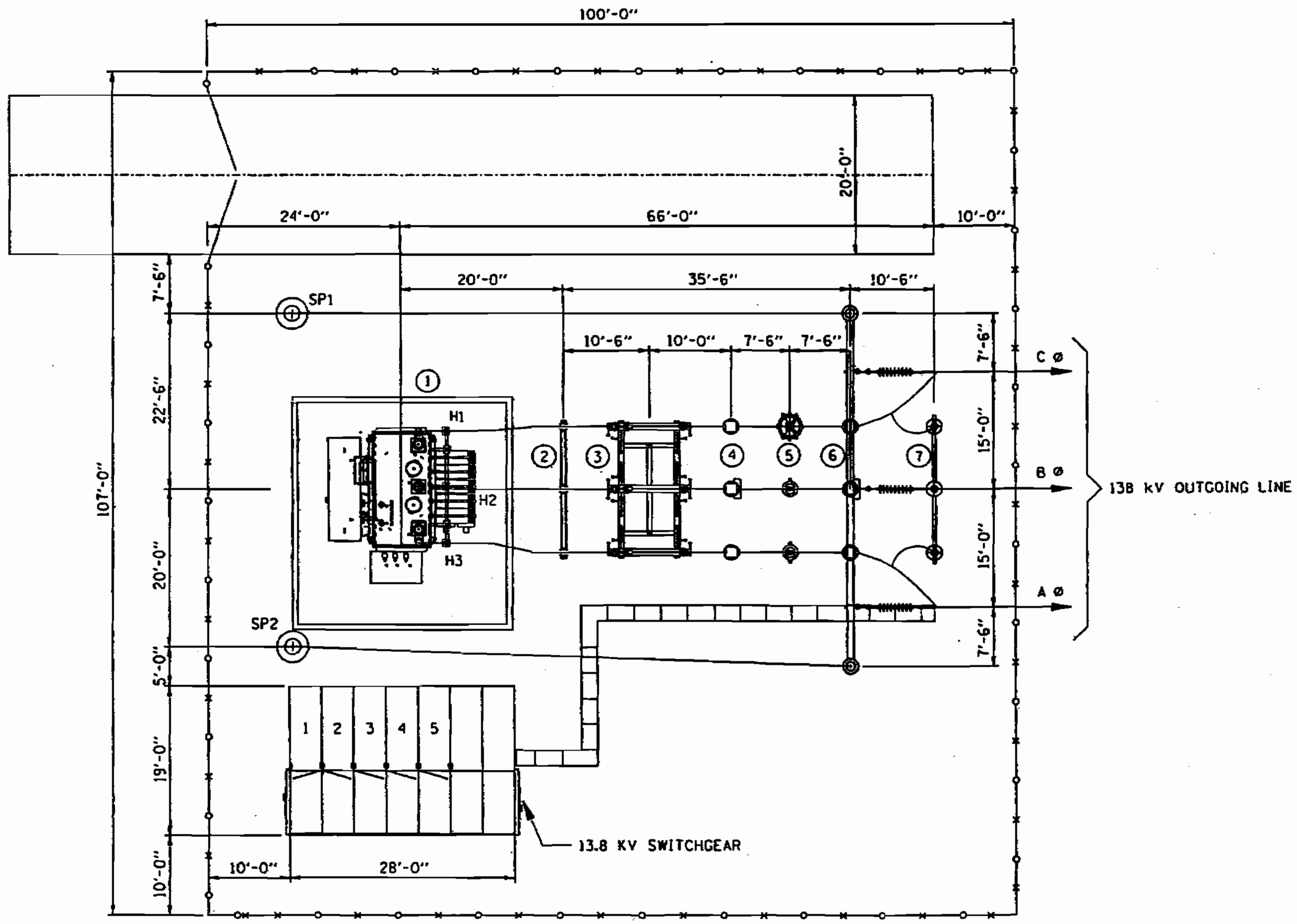

EQUIPMENT LIST:

1. 138/13.8kV 50 MVA TRANSFORMER
2. CIRCUIT SWITCHER
3. DISCONNECT SWITCH, MOTOR OPERATED
4. METERING INSTRUMENT
5. CCVT - LINE TRAP (C Ø)
6. TAKE-OFF STRUCTURE/CT
7. SURGE ARRESTER

SCALE 0 16 32 FEET
1/16" = 1'-0"

FIGURE 3-5

SIXTH WATER POWER STATION
SUBSTATION PLAN

PAGE NUMBER 3-7 SKM-03

MWH

TABLE 3-1
Sixth Water Hydroelectric Powerplant Generating Equipment

Description	Equipment Characteristics
Turbine Inlet Valve	
Type	Spherical
Diameter, in	58
Maximum static head, ft	1,276.75
Centerline elevation, ft	6,327.25
Turbine	
Type	Pelton, 4-jets, single runner
Rated Capacity, kW	41,186
Shaft orientation	Vertical
Rated flow, cfs	476
Rated net head, ft	1,149
Speed, rpm	327.27
Centerline elevation, ft	6,327.25
Generator	
Type	Synchronous
Rated output, kVA	44,670
Rated voltage, V AC	13,800
Power Factor	0.9
Speed, rpm	327.27
Frequency, Hz	60
Step Up Transformer	
Rated output, kVA	50,000
Primary voltage, kV	13.8
Secondary voltage, kV	138
Number of phases	3
Frequency, Hz	60

Transmission Line Route and Connection to the Power Grid

Power to operate the flow control valves at the existing Sixth Water Flow Control Structure is currently supplied by a 1.5 mile long, 7.2 kV line running from a trailer mounted 46/7.2 kV step-down transformer located approximately 1/4 mile south of the outlet of the Syar Tunnel. However, the plant output, as proposed, will greatly exceed this lines capacity. Preliminary estimates indicate that a transmission voltage of 138 kV would be required to maintain the voltage drop and transmission losses within acceptable limits. A general arrangement of the proposed transmission line route for the proposed Sixth Water Hydroelectric Powerplant is shown in Figure 3-6. Figure 3-7 depicts the Sixth Water Powerplant Transmission line- Steel Pole configuration for the 138 kV- 7.2kV power line.

The closest potential interconnection point to the grid is the existing UP&L 46 kV transmission line that runs along Rays Valley road. To connect the powerplant to the existing 46 kV line would require replacing the existing 1.5 mile long, 7.2 kV line with a 138 kV line. In addition, approximately 14 miles of the 46 kV line between the tie with the existing UP&L 138 kV line that runs along Highway 6 and the junction with the 1.5 mile long, 7.2 kV line currently supplying power for the Sixth Water Flow Control Structure valves would have to be replaced by a 138 kV line (see Figure 3-6). The replacement would require new steel poles, insulators, conductors, and a 60-foot right-of-way. The line replacing the existing 46 kV line would include two circuits: one 3-phase 138 kV circuit would be used to evacuate the powerplant output while the other circuit would operate at 7.2 kV single-phase to provide power to the existing customers along this stretch of the line. The single-phase 7.2 kV line would tap into an existing single phase 7.2 kV line just north of Highway 6. Furthermore, a new 138 kV switchyard would likely be required by UP&L to provide operational flexibility to their transmission system.

The Sixth Water Hydroelectric Powerplant would connect with the electrical grid at the existing UP&L 138 kV transmission line (along Highway 6) through a 15.5 mile long, 138 kV transmission line, which would consist of the following two sections:

- A 1.5 mile long, 3-phase 138 kV overhead line which would replace the existing 1.5 mile long, single-phase 7.2 kV line, which currently provides power to the Sixth Water Flow Control Structure valves;
- A 14 mile long, 3-phase 138 kV overhead line which would replace 14 miles of existing UP&L 46 kV line that runs along Rays Valley road. This line would be provided with a second single-phase 7.2 kV circuit to supply power to existing consumers along this stretch of line.

A new 138 kV switchyard would be constructed at the junction of the UP&L 46 kV with Highway 6 to provide UP&L with operational flexibility to their transmission system.

Table 3-2 summarizes the details for transmitting excess power generated at the Sixth Water Hydroelectric Powerplant to the electric grid.

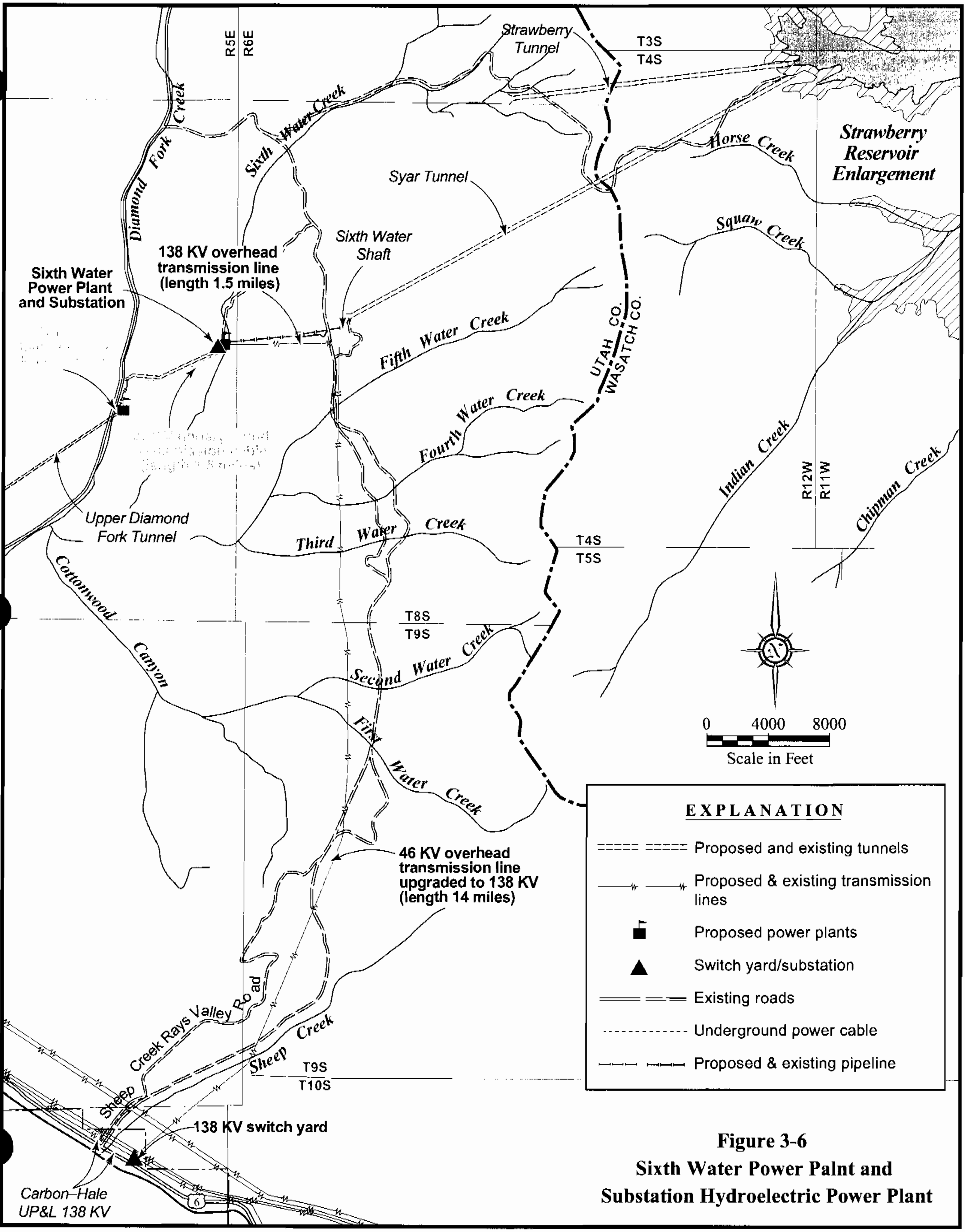

Figure 3-6
Sixth Water Power Palnt and Substation Hydroelectric Power Plant

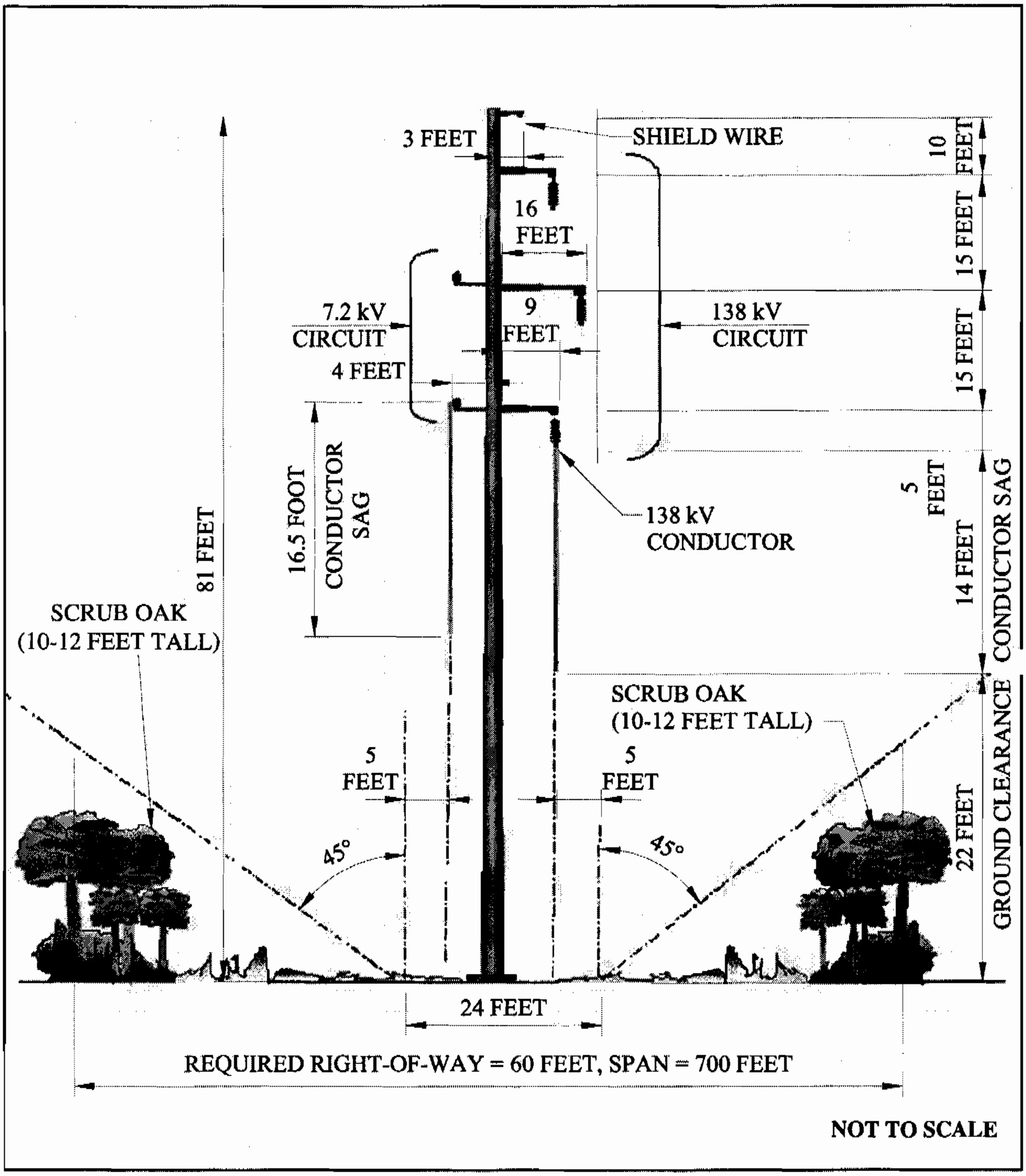

Figure 3-7
Upgraded Power Poles for the Sixth Water Transmission Line

TABLE 3-2 Closest Potential Grid Connection Point						
Power Station	Interconnection to Grid		Transmission Voltage (kV)	Transmission Line Length (Miles)		
	Point	Owner		Overhead	Buried	Total
Sixth Water	Transmission Line	UP	138	15.5	-	15.5

Net Energy Generated

Table 3-3 summarizes the long-term annual average net energy for the Sixth Water Hydroelectric Powerplant. The net energy was estimated at the assumed point of interconnection to CRSP electric grid.

TABLE 3-3 Estimated Net Energy Generated at Sixth Water	
Month	**Net Energy Generated (Kilowatt-hours)**
October	See footnote[1]
November	6,764,660
December	3,740,125
January	5,630,533
February	5,865,647
March	4,940,069
April	4,972,873
May	8,807,533
June	14,800,265
July	23,678,890
August	27,897,696
September	27,186,007
TOTAL	**134,284,298**

[1] The Powerplant would not be operated for generation of electricity when flows through the Powerplant reach a value that is less than 10% of the rated flow for the Powerplant. This condition is described as the parasitic load and is discussed more thoroughly in Attachment A of this Appendix.

ESTIMATION OF PROJECT IMPLEMENTATION COSTS[2]

- Project implementation costs presented in Table 3-4 were estimated at the feasibility level based on Montgomery Watson Harza[3] (MWH's) cost database for similar size hydroelectric projects. The estimates include construction costs, interest during construction, and Owner's costs such as engineering, administration, insurance, legal, and financing fees.

TABLE 3-4
Feasibility Level Cost Estimate
Proposed Sixth Water Powerplant

Line Item	Cost
Construction Field Costs	$29,417,786
Engineering (7.5% of construction costs)	$2,206,334
Construction Management (7.5% of construction costs)	$2,206,334
Land Acquisition [4]	$0
TOTAL	**$33,830,454**

Field Construction Costs

Field construction costs presented on the next page in Table 3-5 were estimated based on parametric cost analysis and include engineering and construction of the civil works, and procurement, installation, testing, and commissioning of the electrical and mechanical equipment under a turnkey, fixed price contract. Construction costs include the following items:

- Civil works;
- Electrical and mechanical equipment; and
- Transmission lines and interconnection.

[2] This cost estimate was performed as a means of evaluating the benefit/cost ratio to select the optimal plant capacity. Cost items were estimated at a feasibility level to achieve this purpose, and do not incorporate or reflect all cost items. In addition, this cost is for the optimal plant capacity of 40 MW. The actual installed capacity of the Sixth Water Powerplant will be 45 MW. This estimation of cost should only be used for the purpose for which it was intended and not as a reflection of the actual project cost.

[3] Montgomery Watson Harza is the District's consultant for the plan formulation, cost estimating and NEPA compliance on the ULS System.

[4] The right-of-way costs for the proposed Sixth Water Hydroelectric Plant are estimated to be $0 because some of the lands are withdrawn lands located within Forest Service boundaries and any further required lands would either be withdrawn lands or lands granted a special use permit.

TABLE 3-5
Utah Lake Drainage Basin Water Delivery System Cost Estimate
Sixth Water Power Plant

Description	%	Labor	Material	Sub Contractor	Equipment Rental	Other Costs	Totals
Construction Cost		2,182,287	2,696,450	15,952,890	179,404	131,980	$21,143,011
General Conditions Labor		841,530					
Construction Labor		1,340,757					
General Conditions Labor Burden	32.00%	269,290					$269,290
Construction Labor Burden	28.00%	375,412					$375,412
Sales Tax	7.50%		202,234				$202,234
Sub-Contractor Bond	2.00%			319,058			$319,058
Equipment Rental Mark-up	24.00%				43,057		$43,057
Other Mark-up	7.00%					9,239	$9,239
Gross Cost							$22,361,301
			Contingency*			20%	$4,472,260
			Total Project (w/o insurance and profit)				**$26,833,561**
			Insurance				
*These cost items are based on Total Field Construction Costs			Builders Risk*			0.311%	$91,489
			General Liability			0.500%	$147,089
			Performance Bond				$159,906
			Total Project (w/o profit)				**$27,232,045**
			Overhead & Profit			7.43%	$2,185,741
			Total Field Construction Costs				**$29,417,786**
			Engineering (7.5% of construction costs)			7.5%	$2,206,334
			Construction Management (7.5% of construction costs)			7.5%	$2,206,334
			Land Acquisition				0
			Total Project Costs				**$33,830,454**

The cost of the civil works pertains to the powerplant, substation, and bifurcation from the pipeline/aqueduct to the powerplant. The selected location of the proposed powerplant is along existing access roads and it was assumed that no new permanent access roads would be required. Consequently, the cost associated with permanent access roads (if required) was not included in the estimates.

The cost of the electrical and mechanical equipment for each powerplant was estimated as a water-to-wire package and includes all of the electrical and mechanical equipment from the turbine inlet valve to the substation (generating equipment, auxiliary equipment, controls, main step up transformers, high voltage switchgear, etc). The cost estimates include supply, transport, installation, testing, and commissioning. The cost of the water-to-wire package was estimated based on the parametric relationship derived from regression analysis of cost data obtained from recent bids. In addition, a lump sum amount of $70,000 was included for additional disconnect switches to accommodate the incoming line from the proposed Upper Diamond Fork Hydroelectric Powerplant.

Construction and funding of the transmission line and interconnection would proceed in accordance with Contract No. 14-06-400-2436 dated May 7, 1962, as amended and supplemented, between Western and UP&L. This contract provides a basis whereby UP&L would participate in construction, provide a portion of the costs, and ultimately take ownership of the new transmission line. The cost of the transmission line and interconnection includes the transmission line from the powerplant to the point of interconnection with the electrical grid, including the necessary upgrades of the existing lines, and the required modifications to the interconnection substation to comply with the UP&L's requirements. The cost of a new 138 kV switchyard at the junction of UP&L 46 kV and 138 kV lines is included for the proposed Sixth Water Hydroelectric Powerplant. The portion of the District and DOI costs for these transmission line additions are included in the ULS System project construction costs and do not constitute a separate portion of the project constructed and funded by Western from CRSP power revenues.

The cost of the water conveyance system (pipelines or aqueducts), pressure-breaking facilities, programmable logic controllers at the water intakes, and communication links between the intake and pressure breaking facilities are associated with the pipelines/aqueducts to supply water for municipal and industrial needs under the Diamond Fork System and the ULS System. Therefore, these costs were not included in this estimate. Construction-related costs for an installed capacity of 40,000 kW are presented previously in Table 3-4 and Table 3-5.

Non-Construction Related Costs

The following contingencies were added to the construction costs to reflect the uncertainty of the estimates:

- Civil structures
- Electrical & Mechanical equipment – powerplants
- Transmission lines and interconnections

- Administration, insurance, legal, financing fees
- Engineering & supervision

Annual Costs

Annual operation, maintenance, and replacement costs (OM&R) for the Sixth Water hydroelectric Powerplant were estimated based on a comparison to the Crystal Powerplant. The Crystal Powerplant is part of the Bureau of Reclamation Colorado River Storage Project located on the Gunnison River in Montrose County, Colorado, near Montrose Colorado. The powerplant has operated since 1978, has an installed capacity of 28 MW at a design head of 207 feet.

The estimate includes administration, personnel, operation, routine and extraordinary maintenance, major repairs, and overhauls, spare parts, and capital expenditures throughout the life of the project. Table 3-6 summarizes the four-year average OM&R costs of the Crystal Powerplant. Table 3-7 shows the annual OM&R costs of the Sixth Water Powerplant which computes to be 13.8 mils per kilowatt-hour of energy generated.

TABLE 3-6
Crystal Powerplant, Montrose County, Colorado

	Crystal				
OM&R Accounts	**FY2000**	**FY2001**	**FY2002**	**FY2003**	**Average**
Supervision/Engineering	$23,645	$25,066	$26,425	$31,484	$26,655
Electrical Expenses	$198,680	$228,161	$203,833	$237,755	$217,107
Structures	$116,027	$88,392	$119,546	$90,616	$103,645
Power Plant	$399,254	$308,626	$1,289,977	$484,370	$620,557
Extraordinary	$285,127	$208,972	$221,213	$1,841,870	$639,296
Miscellaneous	$272,967	$200,143	$254,799	$243,403	$242,828
Total	$1,295,698	$1,059,359	$2,115,792	$2,929,498	$1,850,087

TABLE 3-7
Sixth Water Hydroelectric Powerplant
Estimated Annual Costs

Rated Flow (cfs)	Energy Generated (kilowatt-hours)	Annual OM&R Costs
476	134,284,298	**$1,850,087**

Central Utah Project Completion Program

Chapter 4

October 2004

UTAH RECLAMATION
MITIGATION
AND CONSERVATION
COMMISSION

Chapter 4

Although the same technical and economic methodology discussed in Chapter Three was conducted for the proposed Upper Diamond Fork Powerplant, the powerplant capacity at this location was limited to 5,000 kW. This is due to the voltage limitations of the power cable installed in Tanner Ridge Tunnel that would be used to transmit the electricity generated at the Upper Diamond Fork Powerplant to the substation at the Sixth Water Powerplant for transmission to the power grid.

SITE SELECTION

The proposed Upper Diamond Fork Powerplant would be located adjacent to the existing Upper Diamond Fork Flow Control Structure located at the downstream end of the Upper Diamond Fork Pipeline. The length of the water conveyance system between the vertical shaft adjacent to Sixth Water Flow Control Structure and the proposed Upper Diamond Fork Powerplant is approximately 11,183 feet in length.

CIVIL WORKS

The Upper Diamond Fork Powerplant would be a surface powerhouse in the vicinity of the Upper Diamond Fork Flow Control Structure. The civil works associated with the Upper Diamond Fork Powerplant are similar to those for the Sixth Water Powerplant. The Upper Diamond Fork Powerplant would be connected to the electrical grid via the substation associated with the Sixth Water Powerplant. The powerplant would have a rated installed capacity of 5,000 kW at the generator terminals. An existing 1.5-mile long cable would connect the generator with the step up transformer, which would be located in the Sixth Water substation.

A conceptual perspective of the proposed civil works is shown on Figure 4-1. Plan and cross sectional views of the powerhouse, including equipment layout, are shown in Figures 4-2 and 4-3.

SELECTION OF GENERATING EQUIPMENT

Horizontal axis type turbines were preferred for the Upper Diamond Fork Powerplant due to the relatively small plant rated flow of 120 cfs and to minimize the visual impact of the powerhouse building, which would have only one floor where the turbine(s) and generator(s) would be mounted. In addition, maintenance of the generating units would be carried out using mobile cranes given the small size of the units. Therefore, no powerhouse overhead crane would be provided at this station, which would result in a further reduction of the powerhouse height and associated visual impact. Furthermore, only about 25 ft of the powerhouse structure would be above grade.

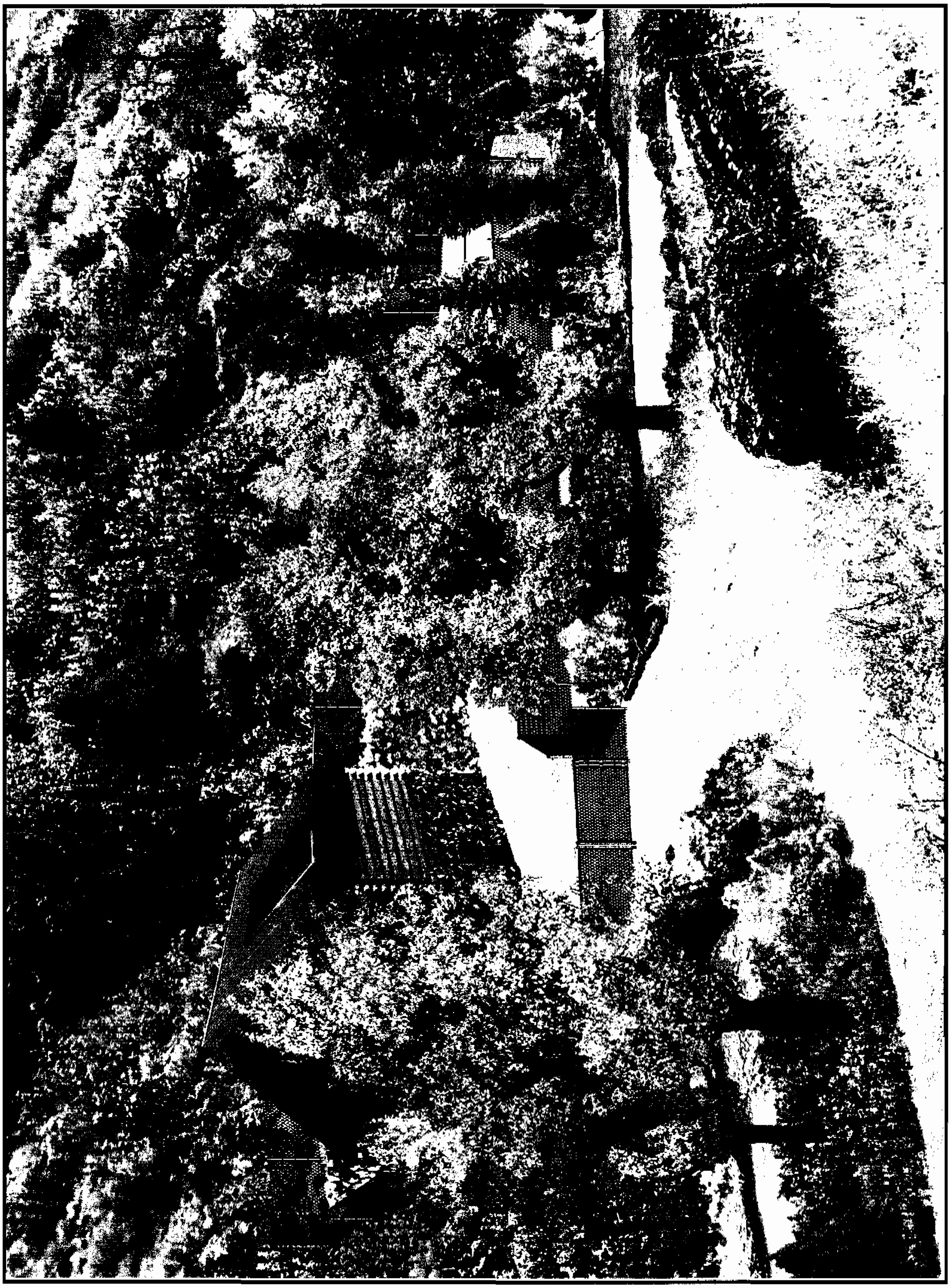

Figure 4-1
Conceptual Perspective of the Proposed Civil Works

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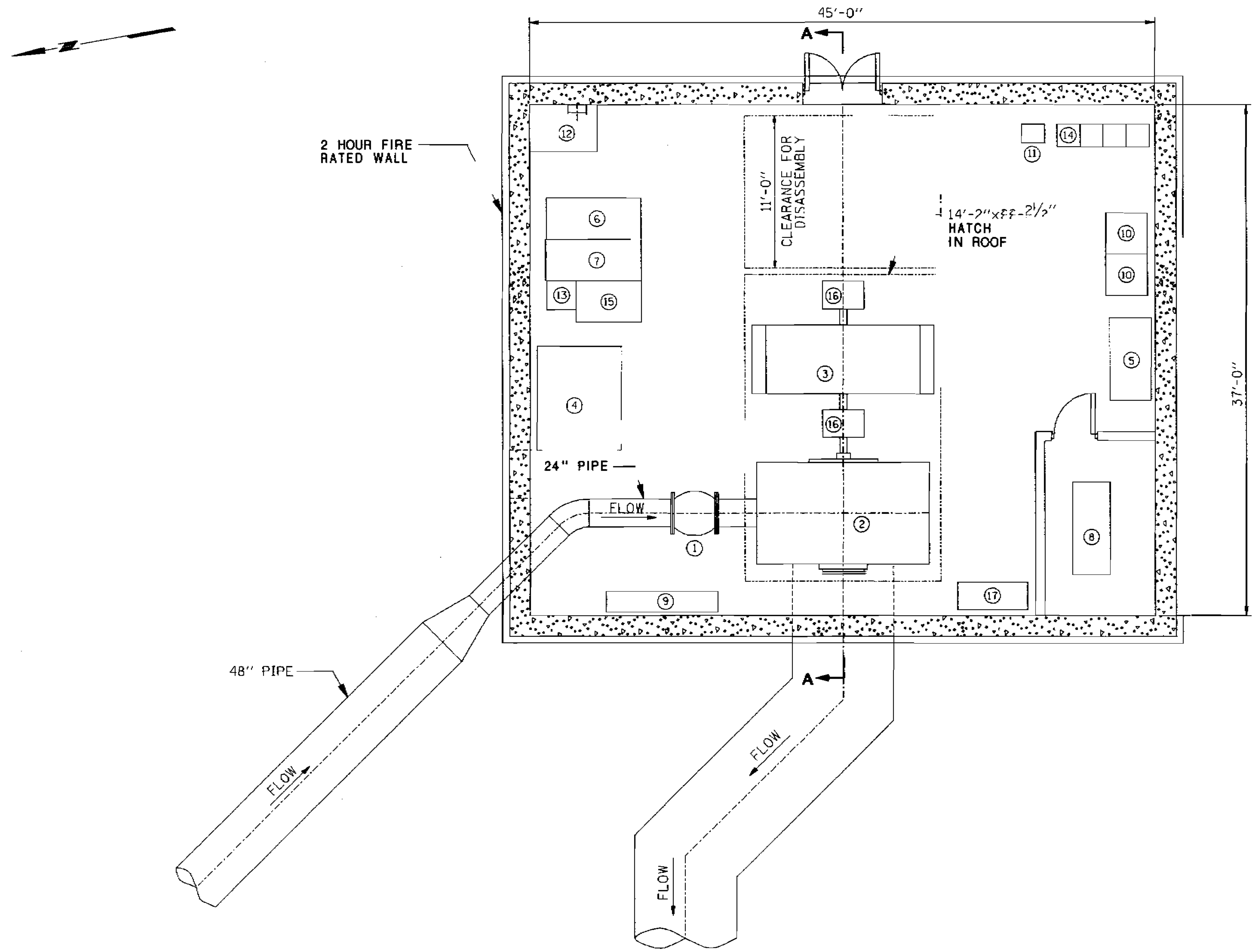

PLAN

EQUIPMENT LIST:

1. SPHERICAL INLET VALVE (36" DIA.)
2. HYDRAULIC TURBINE
3. GENERATOR
4. HYDRAULIC POWER UNIT
5. GENERATOR CONTROL CABINET
6. PT/AVR CABINET
7. GENERATOR BREAKER
8. DIESEL GENERATOR
9. BATTERY
10. BATTERY CHARGER/INVERTER
11. 240/120V LIGHTING PANEL & TRANSFORMER
12. SUMP
13. NEUTRAL GROUNDING CUBICLE
14. MOTOR CONTROL CENTER
15. STATION SERVICE TRANSFORMER
16. GENERATOR BEARING
17. STATION AIR COMPRESSOR

SCALE 0 4 8 FEET
1/8" = 1'-0"

MWH

FIGURE 4-2

UPPER DIAMOND FORK POWERHOUSE CROSS SECTION

PAGE NUMBER 4-3 SKM-01

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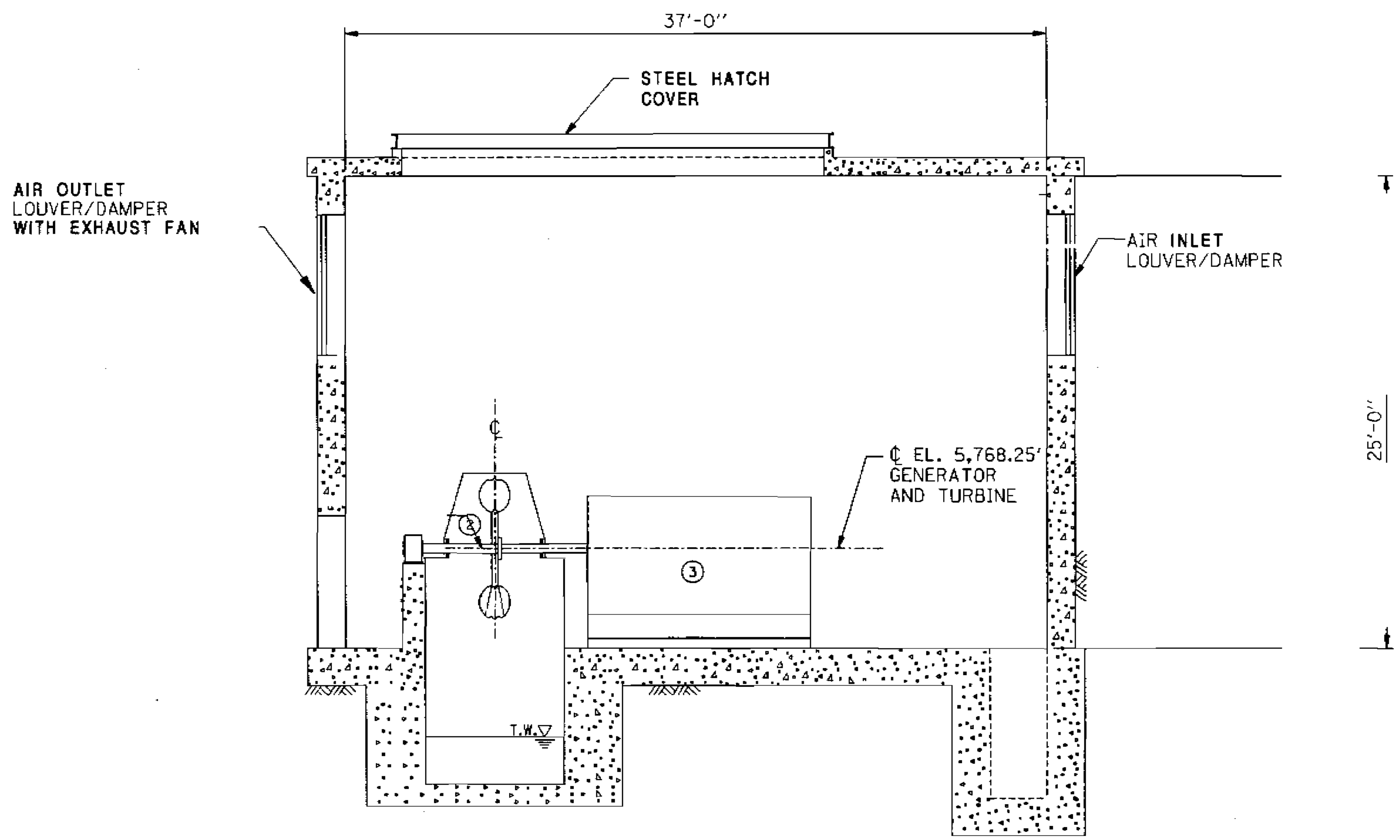


A – A

SCALE 0 4 8 FEET
1/8" = 1'-0"

MWH

FIGURE 4-3

UPPER DIAMOND FORK POWERHOUSE PLAN

PAGE NUMBER 4-4 SKM-02

The proposed Upper Diamond Fork Powerplant would contain a single generating unit consisting of a horizontal shaft, 2-jet Pelton turbine and a synchronous generator directly coupled to the turbine. A 36" diameter spherical valve would be provided at the inlet of the turbine distributor to permit isolation of the unit for maintenance or to shut-off the flow in case of emergency. In addition, a digital governor would be provided for frequency and load control of the generating unit. The generator would be connected to the step up transformer located in the proposed Sixth Water Powerplant substation by an existing 1.5 mile long, 4/0 cable. The powerplant would be provided with the typical mechanical and electrical auxiliary systems for hydro-powerplants. The Upper Diamond Fork Powerplant would not have a separate substation but would use the substation that would be located at Sixth Water.

TABLE 4-1
Upper Diamond Fork Hydroelectric Powerplant Generating Equipment

Description	Equipment Characteristics
Turbine Inlet Valve	
Type	Spherical
Diameter, in	36
Maximum static head, ft	540
Centerline elevation, ft	5,768.25
Turbine	
Type	Pelton, 2-jets
Rated Capacity, kW	5,094
Shaft orientation	Horizontal
Rated flow, cfs	125
Rated net head, ft	540
Speed, rpm	276.9
Centerline elevation, ft	5,768.25
Generator	
Type	Synchronous
Rated output, kVA	5,555
Rated voltage, V AC	13,800
Power Factor	0.9
Speed, rpm	276.9
Frequency, Hz	60

TRANSMISSION LINE ROUTE AND CONNECTION TO THE POWER GRID

Interconnection to the grid would be via the substation associated with the Sixth Water Powerplant through a 1.5 mile long, 13.8 kV transmission line which currently serves features of the completed Diamond Fork System of the Bonneville Unit. This line is located between the proposed Sixth Water and Upper Diamond Fork Powerplants. This line consists of a 4/0, 25 kV copper cable installed in the top of the Tanner Ridge Tunnel (1.05 miles) and in a trench (0.45 miles) for a total length of 1.5 miles. The operating voltage would be 13.8 kV, which is the same as the proposed generator rated voltage and precludes the need for a transformer at the Upper Diamond Fork Powerplant. A general arrangement of the proposed transmission line for Upper Diamond Fork Hydroelectric Powerplant is presented on Figure 4-4.

TABLE 4-2
Grid Connection Point

Power Station	Interconnection to Grid		Transmission Voltage (kV)	Transmission Line Length (Miles)		
	Point	Owner		Overhead	Buried	Total
Upper Diamond Fork	Substation	-	13.8	-	1.5	1.5

NET ENERGY GENERATED

The net energy generated at the Upper Diamond Fork Powerplant was estimated at the assumed point of interconnection to the CRSP electrical grid, which for this powerplant would be the Sixth Water substation. Results are presented in Table 4-3.

TABLE 4-3
Net Energy Generated
(Kilowatt-hours)

Month	Kilowatt-Hours
October	887,668
November	2,897,593
December	1,841,050
January	2,272,205
February	2,289,426
March	2,169,365
April	2,143,837
May	2,882,354
June	3,375,009
July	3,435,885
August	3,396,971
September	3,282,314
Total	**30,873,677**

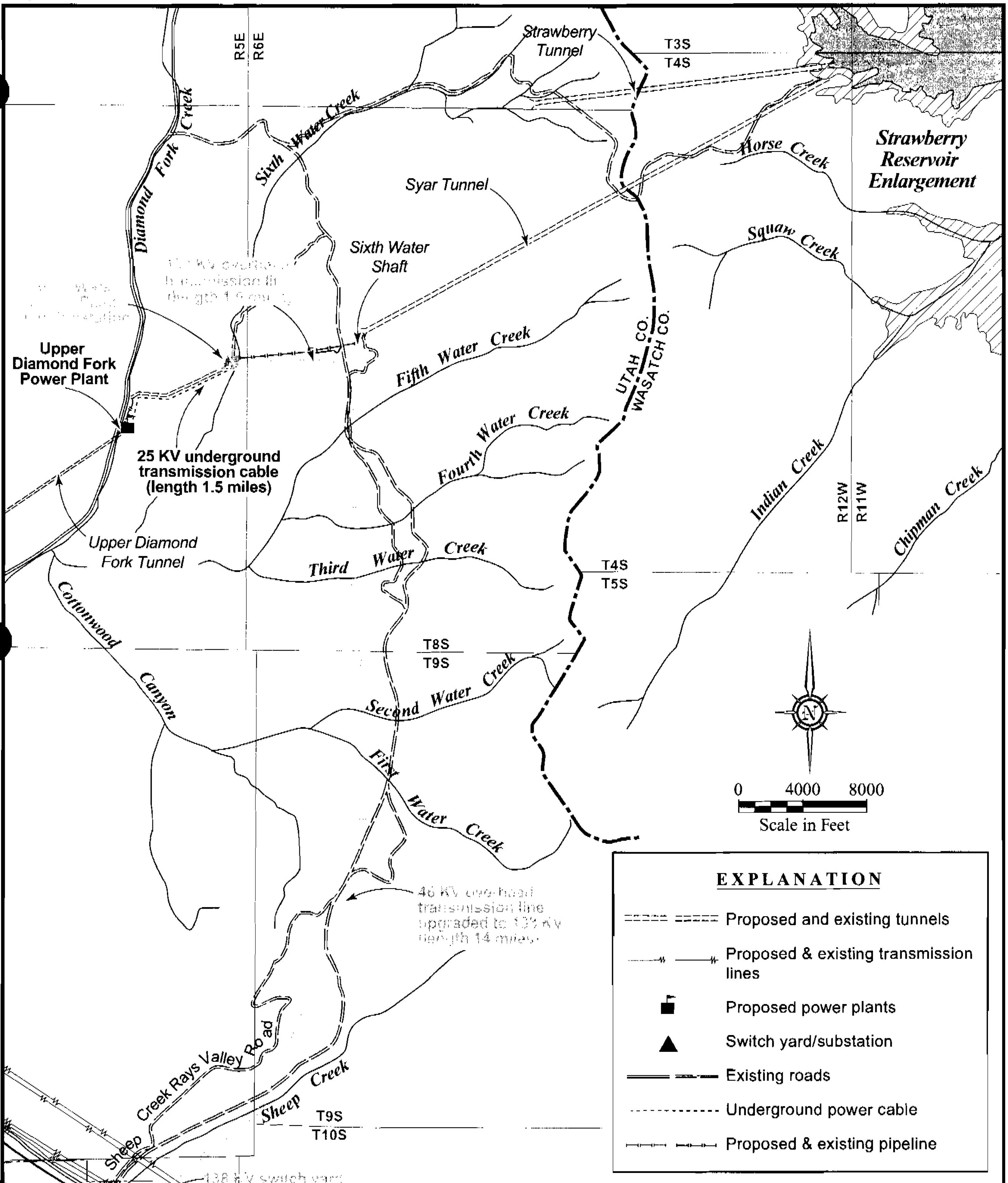


Figure 4-4
Upper Diamond Fork Power Plant

ESTIMATION OF PROJECT IMPLEMENTATION COSTS[1]

Project implementation costs presented in Table 4-4 were estimated at the feasibility level based on MWH's cost database for similar size hydroelectric projects. The estimates include construction costs, interest during construction, and Owner's costs such as engineering, administration, insurance, legal, and financing fees.

TABLE 4-4
Feasibility Level Cost Estimate
Proposed Upper Diamond Fork 5 MW Powerplant

Line Item	Cost
Construction Field Costs	$5,907,020
Engineering (7.5% of construction costs)	$443,026
Construction Management (7.5% of construction costs)	$443,027
Land Acquisition	$0
TOTAL	**$6,793,073**

Field Construction Costs

Field construction costs presented in Table 4-5 on the next page were estimated based on parametric cost analysis and include engineering and construction of the civil works, and procurement, installation, testing, and commissioning of the electrical and mechanical equipment under a turnkey, fixed price contract. Construction costs include the following items:

- Civil works;
- Electrical and mechanical equipment; and
- Transmission lines and interconnection.

The cost of the civil works pertains to the power plant, substation, and bifurcation from the pipeline/aqueduct to the power plant. The selected locations of the proposed power plant are along existing access roads and it was assumed that no new permanent access roads would be required. Consequently, the cost associated with permanent access roads (if required) was not included in the estimates. The cost of the civil works was estimated assuming the following parametric relationship for the civil works (power plant, forebay, and substation) and lump sum amount for the bifurcation.

[1] This cost estimate was performed as a means of evaluating the benefit/cost ratio to select the optimal plant capacity. Cost items were estimated at a feasibility level to achieve this purpose, and do not incorporate or reflect all cost items. This estimation of cost should only be used for the purpose for which it was intended and not as a reflection of the actual project cost.

TABLE 4-5
Utah Lake Drainage Basin Water Delivery System Cost Estimate
Upper Diamond Fork Power Plant

Description	%	Labor	Material	Sub Contractor	Equipment Rental	Other Costs	Totals
Construction Cost		357,593	97,825	3,661,725	105,154	39,490	$4,261,787
General Conditions Labor		318,320					
Construction Labor		39,273					
General Conditions Labor Burden	32.00%	101,862					$101,862
Construction Labor Burden	28.00%	10,996					$10,996
Sales Tax	7.50%		7,337				$7,337
Sub-Contractor Bond	2.00%			73,235			$73,235
Equipment Rental Mark-up	24.00%				25,237		$25,237
Other Mark-up	7.00%					2,764	$2,764
Gross Cost							$4,483,218
			CONTINGENCY*			20%	$896,644
			Total Project (w/o insurance and profit)				**$5,379,862**
			Insurance				
			Builders Risk*			0.311%	$18,371
*These cost items are based on Total Field Construction Costs			General Liability			0.500%	$29,535
			Performance Bond				$40,360
			Total Project (w/o profit)				**$5,468,128**
			Overhead & Profit			7.43%	$438,892
			Total Field Construction Costs				**$5,907,020**
			Engineering (7.5% of construction costs)			7.5%	$443,026
			Construction Management (7.5% of construction costs)			7.5%	$443,026
			Land Acquisition				0
			Total Project Costs				**$6,793,073**

The cost of the transmission line and interconnection includes the transmission line from the powerplant to the point of interconnection with the electrical grid, including the necessary upgrades of the existing lines, and the required modifications to the interconnection substation to comply with the Utility's requirements. The cost of the power cable from Upper Diamond Fork Powerplant to the Sixth Water substation was not included in the cost estimate for Upper Diamond Fork Powerplant given that the power cable has been installed with the construction of Tanner Ridge Tunnel.

The cost of the water conveyance system (pipelines or aqueducts), pressure reducing facilities, programmable logic controllers at the water intakes, and communication links between the intake and pressure reducing facilities are associated with the pipelines/aqueducts to supply water for municipal and industrial needs under the Bonneville Unit's Diamond Fork System and ULS System. Therefore, these costs and associated OM&R costs were not included in the estimate for the power plant.

Non-Construction Related Costs

The following contingencies were added to the construction costs to reflect the uncertainty of the estimates:

- Civil structures
- Electrical & Mechanical equipment – powerplants
- Transmission lines and interconnections
- Administration, insurance, legal, financing fees
- Engineering
- Construction Management

Annual Costs

Annual operation, maintenance, and replacement costs (OM&R) for the Upper Diamond Fork Hydroelectric Powerplant were estimated based on a comparison to the Lower Molina Powerplant. The Lower Molina Powerplant is part of the Bureau of Reclamation Collbran Project located in Mesa County, Colorado, on the south bank of Plateau Creek near Molina, Colorado. The powerplant has operated since 1962, has an installed capacity of 4.9 MW at a design head of 1,400 feet and a maximum water discharge of 50 cfs.

Construction and funding of the transmission line and interconnection would proceed in accordance with Contract No. 14-06-400-2436 dated May 7, 1962, as amended and supplemented, between Western and UP&L. This contract provides a basis whereby UP&L would participate in construction, provide a portion of the costs, and ultimately take ownership of the new transmission line. The cost of the transmission line and interconnection includes the transmission line from the powerplant to the point of interconnection with the electrical grid, including the necessary upgrades of the existing lines, and the required modifications to the interconnection substation to comply with the UP&L's requirements. The cost of a new 138 kV switchyard at the junction of UP&L 46 kV and 138 kV lines is included for the proposed Upper Diamond Fork Hydroelectric Powerplant. The portion of the District and DOI costs for these transmission line additions are included in the ULS System project construction costs and do not constitute a separate portion of the project constructed and funded by Western from CRSP power revenues.

The estimate includes administration, personnel, operation, routine and extraordinary maintenance, major repairs, and overhauls, spare parts, and capital expenditures throughout the life of the project. Table 4-6 summarizes the four-year average OM&R costs of the Lower Molina Powerplant plus estimated costs for extraordinary OM&R. Table 4-7 shows the annual OM&R costs of the Upper Diamond Fork Powerplant which computes to a value of 10.2 mils per kilowatt-hour of energy generated.

TABLE 4-6
Lower Molina Powerplant, Mesa County, Colorado

	Lower Molina				
OM&R Accounts	**FY2000**	**FY2001**	**FY2002**	**FY2003**	**Average**
Supervision/Engineering					
Electrical Expenses	$36,543	$48,184	$48,063	$29,493	$40,570
Structures	$2,570	$3,398	$716	$2,286	$2,243
Power Plant	$133,474	$103,318	$173,795	$287,375	$174,491
Extraordinary	$53,000	$53,000	$53,000	$53,000	$53,000
Miscellaneous	$38,684	$44,685	$49,700	$49,000	$45,517
Total	$264,271	$252,585	$325,274	$421,153	$315,821

TABLE 4-7
Upper Diamond Fork Hydroelectric Powerplant
Estimated Annual Costs

Rated Flow (cfs)	Energy Generated (kilo-watt hours)	Annual O&M Cost
125	30,873,677	$ 315,821

Central Utah Project Completion Program

Chapter 5

October 2004

UTAH RECLAMATION MITIGATION AND CONSERVATION COMMISSION

Electrical energy is needed for project pumping and to replace reductions in power generation at existing hydropower plants caused by operation of the Bonneville Unit. This power is currently provided or will be obtained from power reserved from the Colorado River Storage Project (CRSP) and wheeled or otherwise exchanged by Western Area Power Administration (Western) in accordance with existing or future contract requirements. Table 5-1 presents the project power requirements and their estimated costs at a combined unit cost of 20.72 mills per kilowatt-hour (kWh), the current cost (year 2004) of SLCA/IP power. The estimated power costs do not include any cost associated with wheeling.

TABLE 5-1
Estimated Power Required From Colorado River Storage Project

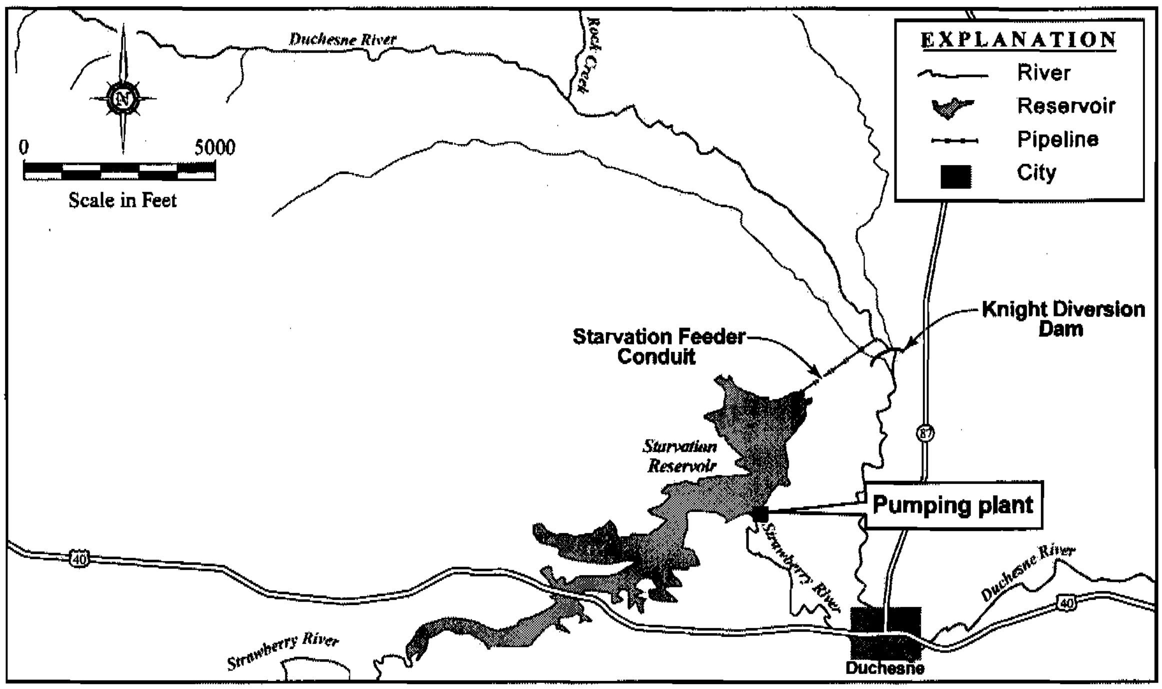
	Energy Required from CRSP		
	Capacity Needed (kilowatts)	**Energy Needed (kilowatt-hours)**	**Annual Energy Cost**
Starvation Collection System			
Delivery of Project Water to Duchesne Facilities[1]	240	900,000	$18,648
M&I System			
Deer Creek Power Plant Replacement Power[2]	1,800	2,100,000	$ 43,512
WCWEP and DRP			
Pumping Plants (irrigation)[3]	3,000	3,000,000	$62,160
Water Conservation, Water Recycling and Conjunctive Use			
Conjunctive Use (northern Utah County)[4]	7,000	5,138,000	$106,459
Water Recycling/Reverse Osmosis[5]	2,500	5,000,000	$103,600
Minimum Flows In Provo River Below Deer Creek Dam			
Pumping to Salt Lake Aqueduct[6]	672	1,048,000	$21,715
CRSP Power Requirements[7]	**15,212**	**17,186,000**	**$356,094**

[1] Information is from 1998 SFN System , Bonneville Unit, Designs and Estimates Appendix
[2] Same as footnote 1
[3] Same as footnote 1
[4] Computed value as part of this updated Supplement to 1988 Definite Plan Report.
[5] Same as footnote 4
[6] Information from engineering staff of Central Utah Water Conservancy District.
[7] These costs do not include any wheeling costs.

STARVATION COLLECTION SYSTEM

The Starvation Reservoir develops irrigation and M&I water for use in Duchesne County. The majority of this M&I water is pumped from the reservoir and treated for culinary water use. The District constructed and operates the intake structure, pump facility, and the Duchesne Valley Water Treatment Plant (DVWTP) adjacent to Starvation Reservoir to withdraw the M&I water from the reservoir and treat it for delivery to project water petitioners. These facilities require an average of approximately 900,000 kilowatt-hours annually for operation as part of the Bonneville Unit M&I System. Figure 5-1 schematically depicts the location of the Starvation Collection System and the pumping plant.

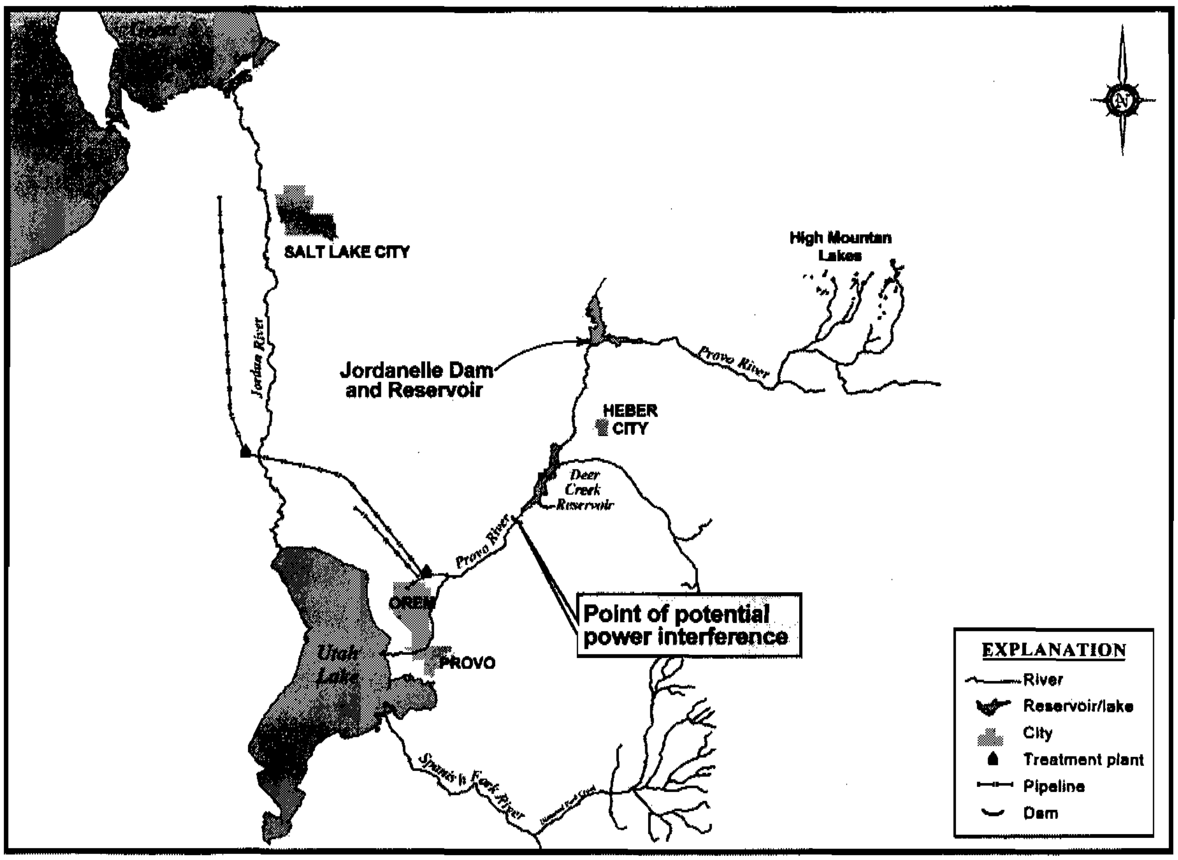
Figure 5-1
Pumping Plant at Starvation Reservoir



BONNEVILLE UNIT MUNICIPAL AND INDUSTRIAL SYSTEM FACILITIES REQUIRING CRSP POWER FOR POWER REPLACEMENT PURPOSES

Replacement power is provided under an existing contract to compensate for a reduction in power generation at Deer Creek Powerplant, located at Deer Creek Dam. Deer Creek Dam is a part of the Provo River Project and was constructed by U.S. Bureau of Reclamation (Reclamation) in the 1940's several years before the Bonneville Unit was authorized. The power plant was constructed as part of an earlier federal project, and its power generation was predicted on releases from Deer Creek Dam without the development of the Bonneville Unit. At the Deer Creek Power Plant (at Deer Creek Dam) the operation of the Bonneville Unit M&I System could reduce power generation by 2.1 million-kilowatt hours per year. The replacement power would cost $43,512 per year at the CRSP rate. The location of the Bonneville Unit's Municipal and Industrial System is shown below in Figure 5-2. An existing contract, Contract No. 94-SLC-0259, dated June 1, 1995, between Reclamation, the Central Utah Water Conservancy District (District), Provo River Water Users Association, PacifiCorp, and Western provides the terms and obligations of the respective parties for this power replacement purpose.

Figure 5-2
Potential for Power Interference at Deer Creek Dam



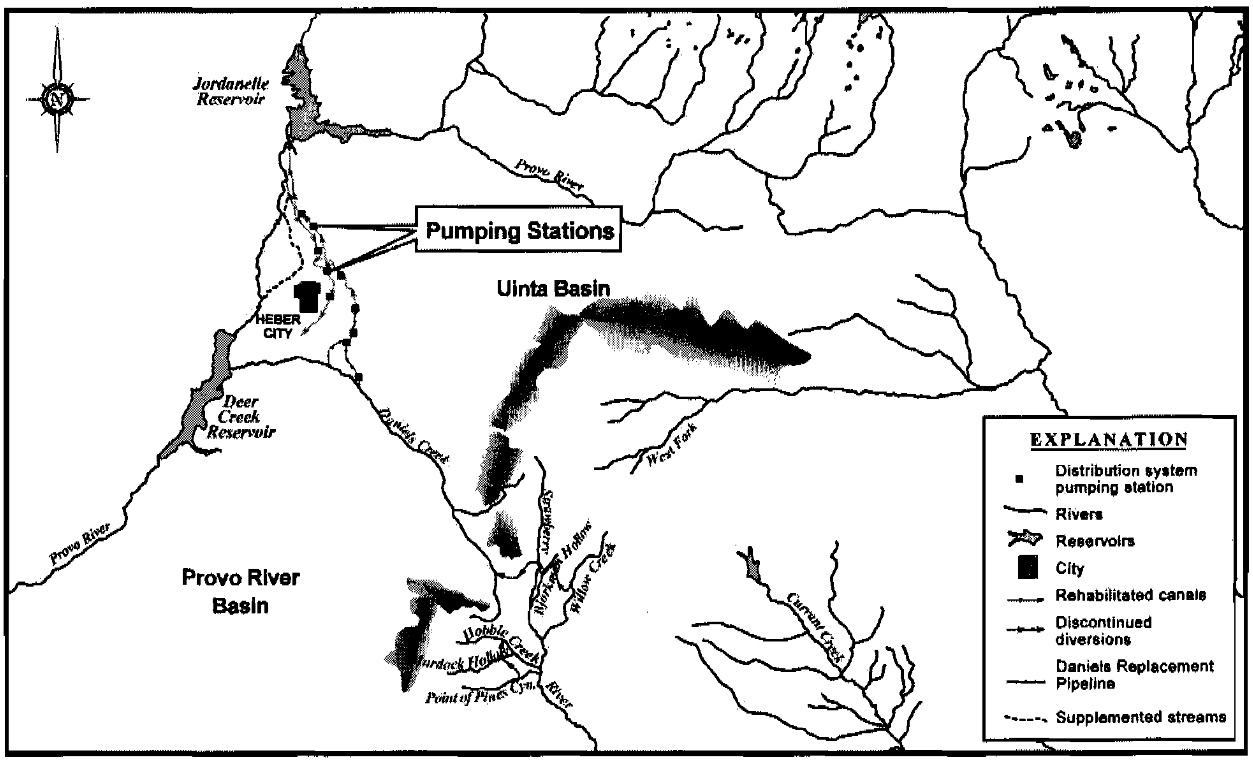
WASATCH COUNTY WATER EFFICIENCY PROJECT

Data for the Wasatch County Water Efficiency Project and the Daniels Creek Replacement Pipeline (WCWEP/DRP) were readily available from the SFN System, 1998 Draft Designs and Estimates Appendix.

The WCWEP/DRP, see Figure 5-3 below, requires 10 pumping stations ranging from 15 horsepower (hp) to 685 hp, for a total of 2,200 hp. The annual pumping energy required for delivery of this portion of Bonneville Unit water would be approximately 3 million kWh and requires a reserved capacity of three megawatts. An existing contract, Contract No. 97-SLC-0343, dated September 28, 1998, between Western, Reclamation, and the Wasatch County Water Efficiency Project provides the terms and obligations of the respective parties for power provided for this project. These energy estimates are based on the following assumptions:

- Pumps used for irrigation diversions are used an average of 2,335 hours per year.
- Pumps used for the Daniel Replacement Pipeline are used an average of 1,345 hours per year.
- No CUP M&I water or supplemental instream water passes through any pumps, or accounts for any of the estimated required pumping energy.

Figure 5-3
Project Pumping for WCWEP/DRP



CUPCA WATER CONSERVATION PROGRAMS

CRSP, as amended by CUPCA, allows for reservation of CRSP energy for some water conservation and other resource management programs. These include:

- Water conservation programs (for example, conjunctive use);
- Water recycling; and
- Reverse osmosis

Based on preliminary estimates, these programs could require approximately 9.5 MW of reserved energy capacity and corresponding annual energy requirements of approximately 10.1 million kWh

Conjunctive Use of Surface and Groundwater

A proposed conjunctive use program in northern Utah County would involve the transfer of project M&I water to groundwater aquifers, accompanied by withdrawal of groundwater at a more beneficial time or place. Conjunctive use of ground and surface waters can reduce peak demand for imported surface water, eliminate or delay the need to construct new conveyance and treatment facilities, and utilize off-peak capacity in existing conveyance facilities. Utilizing a conjunctive use program could reduce pressure placed on surface water sources in northern Utah County by ever-increasing M&I demands. Such a program could provide greater flexibility as well as providing conservation of high-quality runoff. The District has initiated a cooperative effort with the northern Utah County Communities and the U.S. Geological Survey to conduct a three to four-year study of a potential conjunctive use project. If this conjunctive use project is developed, DOI would own the wells and the water supply provided would be a project water supply.

Pumping from wells would be required for extraction of the recharged project M&I water. Preliminary estimates indicate average annual energy requirements for the conjunctive use pumping to be approximately 5,138,000 kilowatt-hours, and would require a reserved capacity of about 7.0 megawatts. Table 5-2 presents the calculation of these numbers. These energy estimates assume infiltration basins would be used for recharge, and does not account for energy expenditures that would be required for pre-treatment and injection if injection wells are used.

TABLE 5-2
Northern Utah County
Estimated Pumping Energy for Conjunctive Use Program

Pumping Lift of 300 feet

Month	Flow (cfs)	Pump Efficiency	TDH (ft)	Brake (hp)	Motor (hp)	Power (kW)	Power (kWH)	Cost of Power ($)
January	0	85%	300	0	0	0	0	0
February	0	85%	300	0	0	0	0	0
March	0	85%	300	0	0	0	0	0
April	0	85%	300	0	0	0	0	0
May	0	85%	300	0	0	0	0	0
June	0	85%	300	0	0	0	0	0
July	74	85%	300	2,963	3,119	2,327	1,731,187	$45,011
August	74	85%	300	2,963	3,119	2,327	1,731,187	$45,011
September	74	85%	300	2,963	3,119	2,327	1,675,343	$43,559
October	0	85%	300	0	0	0	0	$0
November	0	85%	300	0	0	0	0	$0
December	0	85%	300	0	0	0	0	$0
TOTAL						**6,981**	**5,137,718**	**$106,459**
Cost of Power ($/kWH)				$0.02072				
Motor Efficiency				0.95				

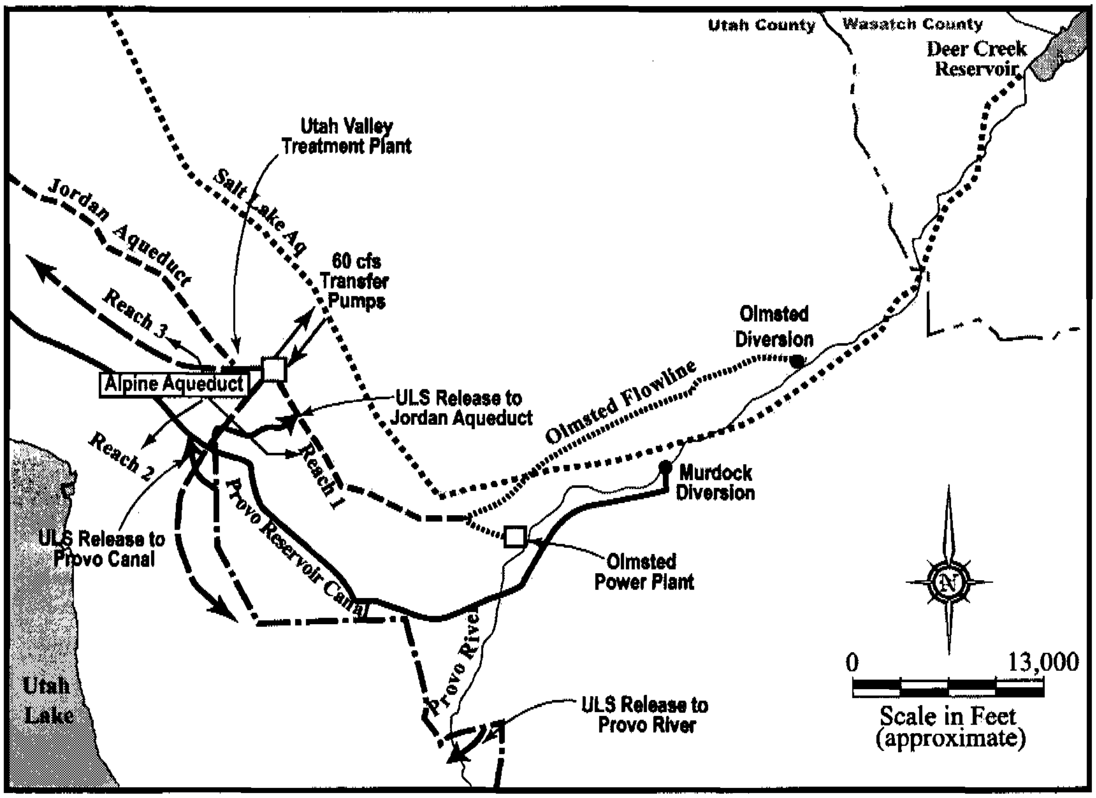
Water Recycling and Reverse Osmosis Treatment of Project Return Flows

Water recycling and potential reverse osmosis treatment of Bonneville Unit M&I return flows are considered to be a part of the water supply of the Bonneville Unit. Initial discussions among DOI, the District, the project water petitioners, and the State Engineer have indicated that there is a high probability that such measures will be implemented in the future. Because of the preliminary nature of the planning associated with these projects, no definitive calculations were attempted. However, as a place-holder, the energy required to deliver the 21,000 ac-ft of recycled project M&I water was estimated to be approximately 5 million kW-hr, and would require 2.5 megawatts of reserved capacity. Future planning efforts will better define these numbers.

ENVIRONMENTAL COMMITMENTS

DOI and Reclamation in their various environmental documents, have made commitments to provide flows in the lower Provo River for the endangered June sucker and for minimum instream flows below Deer Creek Dam. In order to meet the combination of these environmental commitments, it is sometimes necessary under an existing agreement to have Provo River Project water that would have been diverted into the Salt Lake Aqueduct to flow down the Provo River, to be diverted into the Olmsted Aqueduct, and then be pumped into the Salt Lake Aqueduct. This requires about 0.672 MW of capacity with an annual energy need of 1,048,000 kilowatt-hours.

Figure 5-4
Location of Transfer Pumps



Irrigation Wells

The 1988 Bonneville Unit Definite Plan Report included numerous irrigation wells in southern Utah County and Juab County that could become part of a water exchange program through exchanges with Bonneville Unit water rights. This is no longer part of the Bonneville Unit because the project irrigation deliveries that were included in the 1988 plan are now eliminated.

Chapter 6

Central Utah Project Completion Program

Chapter 6

October 2004

UTAH RECLAMATION
MITIGATION
AND CONSERVATION
COMMISSION

This chapter presents the financial and economic evaluation of the hydroelectric power plants that are proposed for Sixth Water and Upper Diamond Fork. The data presented here are from the Financial and Economic Appendix completed as part of the 2004 Supplement to the 1988 Bonneville Unit Definite Plan Report. The analyses should not be confused with the economic analyses completed as part of the optimization of installed power plant capacity.

To the degree it was possible, all benefits and projected costs in the Financial and Economic Appendix as well as in this chapter are enumerated in October 2004 dollars.

FINANCIAL AND ECONOMIC EVALUATION OF POWER

Costs

Costs of project power plants located in the Diamond Fork Drainage are estimated at $40,623,527. The Sixth Water Plant is estimated at $33,830,454 and the Upper Diamond Fork plant is estimated at $6,793,073. Long-term average annual net energy for the two plants is estimated at 165,157,975 kilowatt-hours (kwh). Installed capacity will be 45,000 Kilowatt (KW) for the Sixth Water Plant and 5,000 KW for the Upper Diamond Fork Plant.

Benefits

Power benefits were developed for project power plants by the Economics Group of the U.S. Bureau of Reclamation located in Denver Colorado. The method for determining benefits involves comparing the proposed plants with an alternative source of generation. This cost of the alternative source is referred to as "avoided cost." In this case, the avoided cost alternative is a hypothetical coal-fired base-load power plant and transmission connection, that would be developed without federal assistance and financed at 5.625 percent. Capacity costs for the alternative plant were estimated to be $187 per kilowatt. On average, these plants operate about 65% of the time. Therefore, the capacity costs expressed on a kilowatt-hour basis are 32.8 mils/kwh. Energy costs were estimated at 12.5 mils/kwh. The composite value for both capacity and energy is 45.3 mils/kwh. Power benefits are estimated at $7.5 million annually and are detailed in Table 6-1: Annual Power Benefits.

TABLE 6-1
Annual Power Benefits

	Unit of Measure	Sixth Water Power Plant	Upper Diamond Fork Power Plant	Total
Capacity				
Installed Capacity	kw	45,000	5,000	50,000
Energy				
Annual Net Energy	kwh	134,269,298	30,873,667	165,157,965
Composite Power Value	mils/kwh	45.3	45.3	
Total Power Benefits	**$**	**$6,083,079**	**$1,398,577**	**$7,481,656**

BENEFIT COST ANALYSIS

The power purpose has a positive effect on the benefit cost ratio. If power were excluded from the project the ratio would be 1.25 calculated at the project planning rate (3.125 percent) and 0.69 at the Principles and Guidelines (P&G) planning rate (5.625 percent). When power is included the b/c ratio is 1.27 at the planning rate and 0.71 at the P&G rate. Table 6-2: Benefit Cost Ratio (Annual Costs) summarizes the effect of power on the benefit cost analysis.

TABLE 6-2
Benefit-Cost Ratio (Annual Costs)

	Without Power		With Power		Difference	
	Project Rate (3.125%)	P&G Rate (5.625%)	Project Rate (3.125%)	P&G Rate (5.625%)	Project Rate (3.125%)	P&G Rate (5.625%)
Total Annual Cost	$112,978,436	$202,789,015	$116,522,028	$207,394,887	$3,543,592	$4,605,872
Total Annual Benefits	$140,684,691	$140,684,691	$148,166,347	$148,166,347	$7,481,656	$7,481,656
Benefit Cost Ratio	1.25	0.69	1.27	0.71	0.03	0.02
Net Annual Benefits	$27,706,255	($62,104,324)	$31,644,318	($59,228,540)	$3,938,064	$2,875,784

As displayed in the table above, inclusion of power in the project results in an increase of net benefits. At the project rate (3.125 percent), the increase is $3.9 million annually. At the P&G rate (5.625 percent), the reduction in negative benefits is $2.9 million annually.

COST ALLOCATION

Cost allocation for this study was done using the Use of Facilities (UOF) method as directed by the Comptroller General in a letter of January 26, 1994. More detail on the cost allocation method is included in the Financial and Economics Appendix to the 2004 Supplement to the 1988 Definite Plan Report for the Bonneville Unit.

The UOF method is recognized as an acceptable method of cost allocation by water resource agencies. The Comptroller General recommended it because reliable data are not available for more sophisticated methods such as the Separable Cost Remaining Benefits and Alternative Justifiable Expenditure methods of cost allocation, which are commonly used on water resource projects. The Separable Cost Remaining Benefits method has been used in all previous reports on the Bonneville Unit.

The UOF method allocates specific costs to project purposes served and assigns joint costs by facility to project purposes according to water use. Remaining joint costs are assigned by the same percentage as the total of specific and assigned costs.

Specific Costs. There are three sources of specific costs to be allocated to power: the Upper Diamond Fork Plant; the Sixth Water Plant; and the abandoned power investigations.

Assigned Joint Costs. The allocation of assigned joint costs is based on the expected annual flows through the Upper Diamond Fork and Sixth Water Plants. Refer to the Financial and Economic Appendix to the 2004 Supplement to the 1988 Definite Plan Report for the Bonneville Unit for more detail information. An annual block of 94,726 acre-feet of Bonneville Unit water was designated as the amount to be used in allocating joint costs to power under the Use of Facilities method.

Costs were allocated to this block of water in each of the facilities required to develop, convey, and store it. As a result, a power allocation appears in the following Bonneville Unit facilities: Strawberry Aqueduct and Collection System (SACS); Upper Stillwater Reservoir; Currant Creek Dam and Reservoir; Soldier Creek Dam and Reservoir; the Diamond Fork Pipeline; the Sixth Water Aqueduct; and the Diamond Fork System.

In addition, two other line items also pick up some assigned joint power costs. Starvation Dam and Reservoir develops water that serves as a replacement for water diverted by SACS. This block of SACS replacement water is allocated to match the allocation of SACS. As a result, some power costs are attached to this block of water in Starvation Dam and Reservoir. Title V of CUPCA contains the Ute Indian Rights Settlement. Costs associated with the settlement are also allocated in the same percentages as SACS because the settlement was necessary to perpetuate the transbasin diversion. Hence, Title V costs are also proportionately allocated to power.

Modified Use of Facilities Approach. Application of a strict UOF allocation of costs to power resulted in an allocation of over $540.3 million to power (see Table 6-3). This amount would result in a power rate greater than its market value. Consequently, a modified use of facilities approach has been applied to the power allocation. Under this approach, the costs allocated to power will be limited to the sum of the expected revenues from sales of power and other offsets to power costs. In other words, the cost allocation will make certain that the total of these offsets to power costs will equal or exceed power costs. The modified use of facilities approach required the following steps.

1. Identification of Power Revenues and Offsets to Power Costs. There are off-sets to power repayment that may be used to identify the amount that will be allocated to power: revenue from power sales; the lease of power privilege at Jordanelle; local cost share associated with power facilities; and non-reimbursability of abandoned power investigations. Table 6-4 summarizes these offsets to power costs and develops the marketability of power. The result is an allocation to power of $161.0 million.

2. Division of Power Costs between Construction and IDC. In the initial allocation of full costs to power, 86 percent of costs were construction cost and 14 percent were IDC. The $161.0 million allocated to power will be divided on the same ratio with $138.8 million in costs being allocated to construction and $22.2 million being allocated to IDC.

3. Allocation of Specific Costs to Power. Table 6-5 summarizes the allocation of specific costs to power. The total specific costs (construction and IDC) amount to $54.7 million.

4. Allocation of Assigned Joint Costs to Power. Table 6-5 summarizes the allocation of assigned joint costs to power. After the allocation of specific costs to power, $85.5 million remained to be allocated to assigned joint construction costs and $20.8 million remained to be allocated to assigned joint IDC costs. The assigned joint costs for power will be allocated to each facility in the same percentage that it would have been allocated under the unmodified UOF approach.

   For example, in the unmodified UOF approach, 1.15 percent of the total amount allocated to assigned joint power construction costs was allocated to Starvation Dam and Reservoir. In the modified use of facilities approach, 1.15 percent of amount available to allocate to assigned joint power construction costs will be allocated to Starvation Dam and Reservoir.

HYDROPOWER REPAYMENT

Power Repayment Obligation

Table 6-6: Summary of Power Repayment shows the total allocation to power and the application of adjustments and offsets to power repayment. The total amount allocated to power (total construction and IDC costs) under the modified UOF method is approximately $161.0 million. When deductions are made for local cost share and abandoned power investigations, the remaining power repayment obligation is approximately $132.9 million.

The amortization of the net repayment obligation (over 50 years at 3.222 percent interest) results in an annual payment of approximately $5.4 million. The Jordanelle LOPP is expected to provide average annual revenue of approximately $115,000, leaving $5.3 million to be provided from sales of the power generated at the Upper Diamond Fork and Sixth Water power plants. The power will be marketed at approximately 45 mils/kwh. Of the 45 mils/kwh, 13.1 mils/kwh is estimated to be required for operation, maintenance, and replacement of project facilities. This leaves approximately 31.9 mils/kwh to be applied to repayment. At 31.9 mils/kwh, the annual revenue generated is expected to equal $5.3 million. Table 6-6: Summary of Power Repayment summarizes repayment of costs allocated to power.

A contract among the Department of the Interior, the District, and the Western Area Power Administration will establish the following:

- the District will repay to the United States the net cost allocated to power in 50 annual installments;
- the District will operate and maintain the power plants;
- the Western Area Power Administration will market the power;
- from power proceeds, Western will reimburse the District for operation and maintenance; and
- from power proceeds, Western will annually remit to Reclamation an amount equal to the District's annual repayment obligation.

TABLE 6-3
Power Costs Calculated at Full Share of Costs

Feature	Power - Percent of Costs	Power Construction	Percent of Power Construction Costs	Total Construction	Power IDC	Percent of Power IDC Costs	Total IDC @ 3.222 Percent	Total Power Costs (Construction and IDC)
Assigned Joint Costs								
Starvation Dam and Reservoir	22.47%	$4,745,140	1.15%	$21,113,505	$4,508,656	6.16%	$20,061,269	$9,253,796
Upper Stillwater Dam and Reservoir	35.28%	$87,267,011	21.16%	$247,353,876	$17,041,457	23.28%	$48,303,139	$104,308,468
Currant Creek Dam and Reservoir	35.28%	$10,168,795	2.47%	$28,822,928	$3,720,279	5.08%	$10,544,942	$13,889,074
Soldier Creek Dam and Reservoir	40.02%	$20,391,552	4.94%	$50,958,000	$2,980,442	4.07%	$7,448,054	$23,371,995
Strawberry Aqueduct	35.28%	$93,858,246	22.76%	$266,036,397	$23,629,129	32.28%	$66,975,557	$117,487,375
Syar Tunnel	42.87%	$32,758,878	7.94%	$76,405,796	$9,109,783	12.44%	$21,247,376	$41,868,661
Sixth Water Aqueduct	42.87%	$15,291,148	3.71%	$35,664,601	$4,472,595	6.11%	$10,431,744	$19,763,743
Diamond Fork System	42.87%	$63,272,145	15.34%	$147,574,000	$7,746,788	10.58%	$18,068,370	$71,018,934
Title V	35.28%	$84,684,542	20.53%	$240,034,000	$0	0.00%	$0	$84,684,542
Sub-Total AJC:		**$412,437,457**	**100.00%**	**$1,113,963,103**	**$73,209,131**	**100.00%**	**$203,080,450**	**$485,646,587**
Specific Costs								
Upper Diamond Fork Power Plant	100.00%	$6,793,073		$6,793,073	$108,953		$108,953	$6,902,026
Sixth Water Power Plant	100.00%	$33,830,454		$33,830,454	$1,357,689		$1,357,689	$35,188,143
Discontinued Investigations	100.00%	$12,596,000		$12,596,000	$0		$0	$12,596,000
Sub-Total: Specific Costs		**$53,219,527**		**$53,219,527**	**$1,466,642**		**$1,466,642**	**$54,686,169**
Total Power Costs		**$465,656,984**			**$74,675,772**		**$540,332,756**	
Percentage		**86.18%**			**13.82%**			

TABLE 6-4
Sources of Power Revenues
(Section 5 Construction and IDC)

Power - Offsets to Construction and IDC Costs				**Annual Generation (kwh)**	**Annual Revenue @ 31.9 mils[1]**	**Capitalized Value of Expected Power Revenues**
Upper Diamond Fork Power Plant				30,873,677	$984,870	$24,306,101
Sixth Water Power Plant				134,284,298	$4,283,669	$105,718,789
Jordanelle LOPP					$114,694	$2,830,590
Total Power Revenues from Sales:				**165,157,975**		**$132,855,481**
Power - Local Cost Share	**Construction Costs Allocated to Power**	**IDC Allocated to Power**	**Local Cost Share (%)**	**Construction LCS**	**IDC LCS**	**Local Cost Share ($)**
Upper Diamond Fork Power Plant	$6,793,073	$108,953	35.00%	$2,377,576	$38,134	$2,415,709
Sixth Water Power Plant	$33,830,454	$1,357,689	35.00%	$11,840,659	$475,191	$12,315,850
Diamond Fork System	$13,118,029	$2,198,971	5.18%	$679,514	$113,907	$793,421
Total Local Cost Share:				**$14,897,748**	**$627,231**	**$15,524,980**
Discontinued Investigations						
Discontinued Investigations	$12,596,000					**$12,596,000**
Total Power Marketability:						**$160,976,460**

[1] Power will be marketed at 45.0 mils/kwh with 13.1 mils being allocated to operation, maintenance and replacement and 31.9 mils applied to repayment of the power allocation.

TABLE 6-5
Power Allocation Constrained by Power Marketability

Feature	Percent of Costs to Power (Construct)	Costs Allocated to Power (Construct)	Percent of Costs to Power (IDC)	Costs Allocated to Power (IDC)	Total
Total Revenues to be Allocated		**$138,728,982**		**$22,247,479**	**$160,976,460**
Percentage (construction/IDC)			13.82%	86.18%	100.00%
Specific Costs					
Discontinued Investigations	100.00%	$12,596,000	100.00%	$0	$12,596,000
Upper Diamond Fork Power Plant	100.00%	$6,793,073	100.00%	$108,953	$6,902,026
Sixth Water Power Plant	100.00%	$33,830,454	100.00%	$1,357,689	$35,188,143
Sub-Total Specific Costs		**$53,219,527**		**$1,466,642**	**$54,686,169**
Available for Assigned Joint Costs		**$85,509,455**		**$20,780,837**	**$106,290,292**
Assigned Joint Costs					
Starvation Dam and Reservoir	1.15%	$983,796	6.16%	$1,279,808	$2,263,604
Upper Stillwater Dam and Reservoir	21.16%	$18,092,815	23.28%	$4,837,317	$22,930,131
Currant Creek Dam and Reservoir	2.47%	$2,108,267	5.08%	$1,056,023	$3,164,289
Soldier Creek Dam and Reservoir	4.94%	$4,227,721	4.07%	$846,016	$5,073,737
Strawberry Aqueduct	22.76%	$19,459,356	32.28%	$6,707,266	$26,166,622
Syar Tunnel	7.94%	$6,791,803	12.44%	$2,585,865	$9,377,667
Sixth Water Aqueduct	3.71%	$3,170,269	6.11%	$1,269,572	$4,439,841
Diamond Fork System	15.34%	$13,118,029	10.58%	$2,198,971	$15,317,000
Title V	20.53%	$17,557,399	0.00%	$0	$17,557,399
Sub-Total AJC	**100.00%**	**$85,509,455**	**100.00%**	**$20,780,837**	**$106,290,292**

Western has committed to initiate a process whereby it would market the power by one or more of the following methods: integrating the power into its Salt Lake City – Integrated Projects (SLCA-IP) and delivering it to existing firm-power customers; marketing it to a subset of the SLCA-IP firm-power customers who are interested in receiving additional hydropower from Western; allocating the power to existing and/or new firm-power preference customers separately from the SLCA-IP; marketing the power to Federal facilities and other preference customers who have requirements or interests in receiving renewable resources; or marketing the power to preference and non-preference entities using some combination of short- and/or long-term power sales contracts.

OM&R Assessment

Table 6-6: Summary of Power Repayment shows total estimated annual OM&R charges associated with the Upper Diamond Fork and Sixth Water Power plants. The Central Utah Water

Conservancy District will operate and maintain the power plants. OM&R costs are estimated at $2.2 million annually. The estimated annual OM&R charge is based on a composite OM&R rate of 13.1 mils/kwh for the two plants. The annual OM&R charge will be established by the District for each OM&R year and will vary depending on actual expenses incurred. Western will reimburse these costs annually from power revenues. Additional OM&R costs for transmission and marketing will be the responsibility of Western.

TABLE 6-6
Summary of Power Repayment

Power Investment	
Construction Cost	$138,728,494
Reimbursable IDC	$22,247,488
Total Power Investment	**$160,975,981**
Less:	
Local Cost Share (Construction)	($14,897,748)
Local Cost Share (IDC)	($627,231)
Abandoned Power Investigations Costs	($12,596,000)
Net Power Investment	**$132,855,002**
Power Revenues	**Total**
Amortization of Power Investment (50 Yrs @ 3.222%)	$5,383,200
Annual Revenue from Jordanelle LOPP	$114,700
Annual Revenue from Sales of Power (Paid by Power Users)	$5,268,500
Annual OM&R for Upper Diamond Fork and Sixth Water Power Plants (Paid by Power Users)	$2,166,000

Attachment A

Central Utah Project Completion Program

Attachment A

October 2004

UTAH RECLAMATION MITIGATION AND CONSERVATION COMMISSION

ATTACHMENT A
OPTIMIZATION OF INSTALLED CAPACITY

The optimization of the installed capacity was carried out for each of the hydroelectric power facilities. However, the maximum capacity of the Upper Diamond Fork Power Plant was limited to 5 MW, which is the capacity of the power cable currently installed in the Tanner Ridge Tunnel.

The optimization process encompassed the following activities:

- Selection of a range of plant flows;
- Estimation of energy production;
- Estimation of energy benefits;
- Estimation of project implementation costs;
- Estimation of operation and maintenance (O&M) costs;
- Economic analysis; and
- Selection of optimum installed capacity.

As described in Chapter 2, an economic analysis was conducted as part of the Optimization Analysis. Two methods were investigated for selecting the optimum installed capacity - the present value of net benefits (NPV) and the benefit-cost (B/C) ratio. While this methodology is adequate from a planning perspective, it should not be confused with the prescribed method of estimating benefits and of cost allocation for the Bonneville Unit of the Central Utah Project. Regulations for the economic evaluation of the Bonneville Unit were prescribed in 1994 by the United States General Accounting Office (GAO), which recommended the Use of Facilities Cost Allocation Method from the Central Valley Project (March, 1992). Therefore, use of the results of this economic analysis were limited to the purpose of determining the optimum installed capacity and are not valid or recommended for any other use.

SELECTION OF RANGE OF INSTALLED CAPACITIES

To perform the optimization analysis, a range of plant flows were selected at each plant and the required generator size was calculated for each flow. Table A-1 summarizes the flows evaluated for each power plant and the corresponding installed capacities.

TABLE A-1
Range of Flows and Associated Generator Capacity

Plant Rated Flow (cfs)	Plant Installed Capacity (kW)
Sixth Water Power Plant	
100	9,225
200	18,153
300	26,706
400	34,561
500	41,598
600	47,904
Upper Diamond Fork Power Plant	
80	3,175
100	3,995
125	5,000

ESTIMATION OF ENERGY PRODUCTION

The energy generation estimated for the power plants is the net energy at the assumed metering point (assumed point of interconnection to the grid) and consists of the gross energy at the high voltage side of the transformer minus the following losses:

- Parasitic load (internal consumption);
- Scheduled maintenance and unscheduled outages; and
- Transmission losses.

Gross Energy

An Excel spreadsheet energy simulation model was developed to estimate the power and energy capabilities of the proposed power facilities. The model uses the monthly average water releases from the Strawberry Reservoir estimated for the period from 1950 to 1999 and assumes that the flows are constant and uniform throughout each day of the month. The estimated flow releases for conveying water from the Strawberry Reservoir to the Utah Lake Drainage Basin were presented previously in Table 3-1 in Chapter 3 of this Power Appendix.

For each month of the period of analysis (1950 to 1999), the model determines the following parameters as a function of both the flow release for that month and the plant rated flow:

- hydraulic headlosses;
- net head;
- turbine efficiency;
- overall plant efficiency (turbine, generator, and transformer); and
- monthly power and energy at the high voltage side of the transformers.

Input data to the model consists of estimated monthly average water releases, plant characteristics, and operating criteria.

The reservoir and forebay elevations, centerline of the turbines, and gross heads assumed for each power plant are summarized in Table A-2.

TABLE A-2
Reservoir and Forebay Details

Power Plant	Reservoir/Forebay Elevation (ft)	Turbine Centerline (ft)	Tail Water Level (ft)	Gross Head (ft)
Sixth Water	7,582(1)	6,327.25	N/A	1,254.75
Upper Diamond Fork	6,310(2)	5,768.25	N/A	541.75

Notes:
1) Average reservoir elevation (maximum 7,604 ft and minimum 7,560 ft)
2) Assumed average water elevation in vertical shaft.

Hydraulic headlosses were estimated for each power plant and include friction and form losses. Friction losses were estimated using the following formula (Darcy-Weisbach):

$$\text{FrictionLoss} = f \cdot \frac{L}{D} \cdot \frac{V^2}{2 \cdot g}$$

where:

Friction Loss = hydraulic friction headloss (in pipeline, tunnel, etc);
f = Darcy-Weisback friction factor (see formula below);
V = water velocity (in pipeline, tunnel, etc.);
D = Internal diameter (pipeline, tunnel, etc.); and
g = acceleration of gravity (assumed at 32.174 ft/sec^2).

The Darcy-Weisbach friction factor (f) was calculated using the following formula:

$$f := \frac{1.325}{\left[\ln\left(\frac{\frac{\varepsilon}{D}}{3.7} + \frac{5.74}{(Re)^{.9}}\right)\right]^2}$$

where:

f	= Darcy-Weisback friction factor;
ε	= wall roughness (pipeline, tunnel, etc.);
D	= internal diameter (pipeline, tunnel, etc.); and
Re	= Reynolds number (see formula below).

$$\boxed{Re := \frac{V \cdot D}{\nu}}$$

where:

Re	= Reynolds number;
V	= water velocity (pipeline, tunnel, etc.);
D	= internal diameter (pipeline, tunnel, etc.); and
ν	= water viscosity.

The following criteria, parameters, and assumptions were used in estimating friction headlosses:

- Wall roughness (ε) for use in the Darcy-Weisbach formula:
  - Sixth Water concrete lined tunnel - 0.0787"
  - Sixth Water steel liner and pipeline - 0.0039"
  - Upper Diamond Fork concrete lined tunnel & shaft - 0.0787"
  - Upper Diamond Fork steel pipeline - 0.0039"

- Internal Diameter
  - Sixth Water Aqueduct - as constructed
  - Upper Diamond Fork Aqueduct - as constructed

- Length of water conveyance
  - Sixth Water - 41,281 ft
  - Upper Diamond Fork - 11,183 ft

- Water viscosity (at 50° F) - 1.41×10^{-5} ft^2/sec

Form losses include the hydraulic headlosses in singularities such as trashracks, water intakes, bends, transitions, bifurcations, valves, etc., and were estimated using the following formula:

$$\boxed{FormLoss := K \cdot \frac{V^2}{2 \cdot g}}$$

where:

Form Loss = hydraulic headloss at singularity (i.e., trashracks, bends, etc.);
K = headloss coefficient (function of singularity);
V = water velocity at singularity (for transitions, V is the difference in velocity at the upstream and downstream sections); and
g = acceleration of gravity (assumed at 32.174 ft/sec^2).

The characteristics of the singularities (bends, transitions, etc.) in the water conveyance system for the proposed Sixth Water Hydroelectric Plant were obtained from available construction drawings and were used to estimate the form hydraulic headlosses. The characteristics of the singularities (bends, transitions, etc.) in the water conveyance system for the Upper Diamond Fork Hydroelectric Plant were not available for this optimization study. Therefore, the form losses for the power facilities for the Upper Diamond Fork Hydroelectric Plant were estimated as a percentage of the hydraulic friction loss. For these plants, the form losses were assumed to be 2.5% of the friction hydraulic headlosses, which was the percentage obtained for the Sixth Water power Plant based on detailed calculations of the form losses.

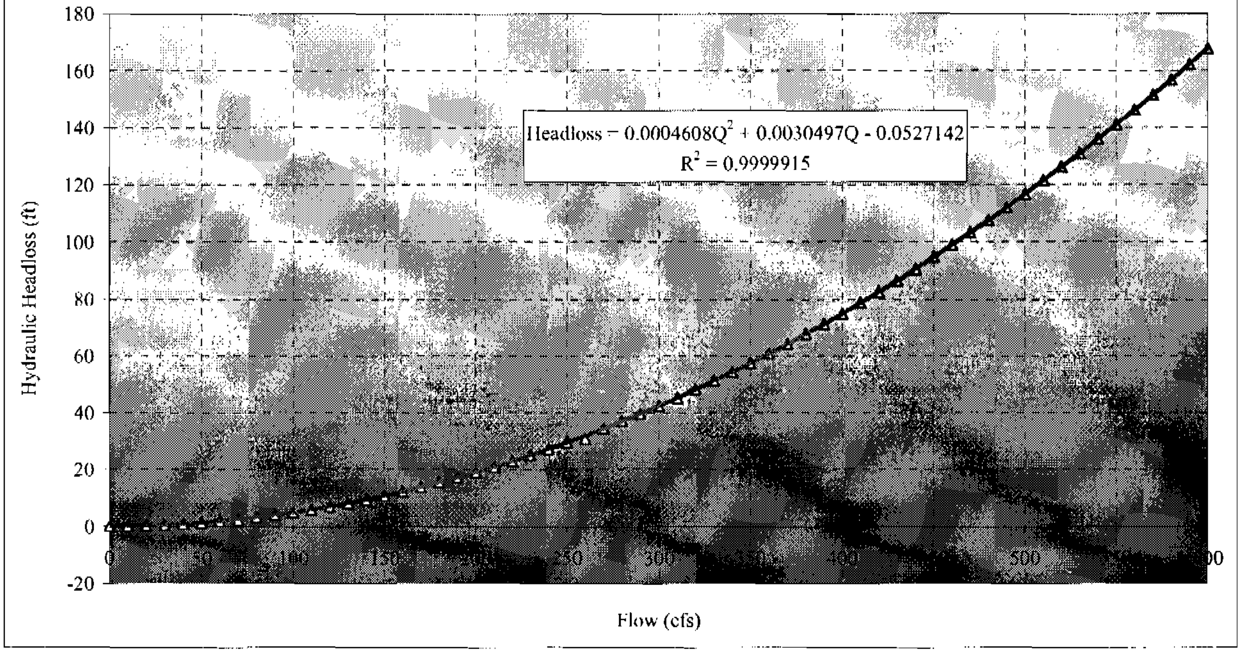
The range of flow assumed for each power plant to estimate form and friction hydraulic headlosses are summarized in Table A-3.

TABLE A-3
Flow Range Used to Estimate Hydraulic Headlosses

Power Plant	Flow Range (cfs)
Sixth Water	0 to 650
Upper Diamond Fork	0 to 600

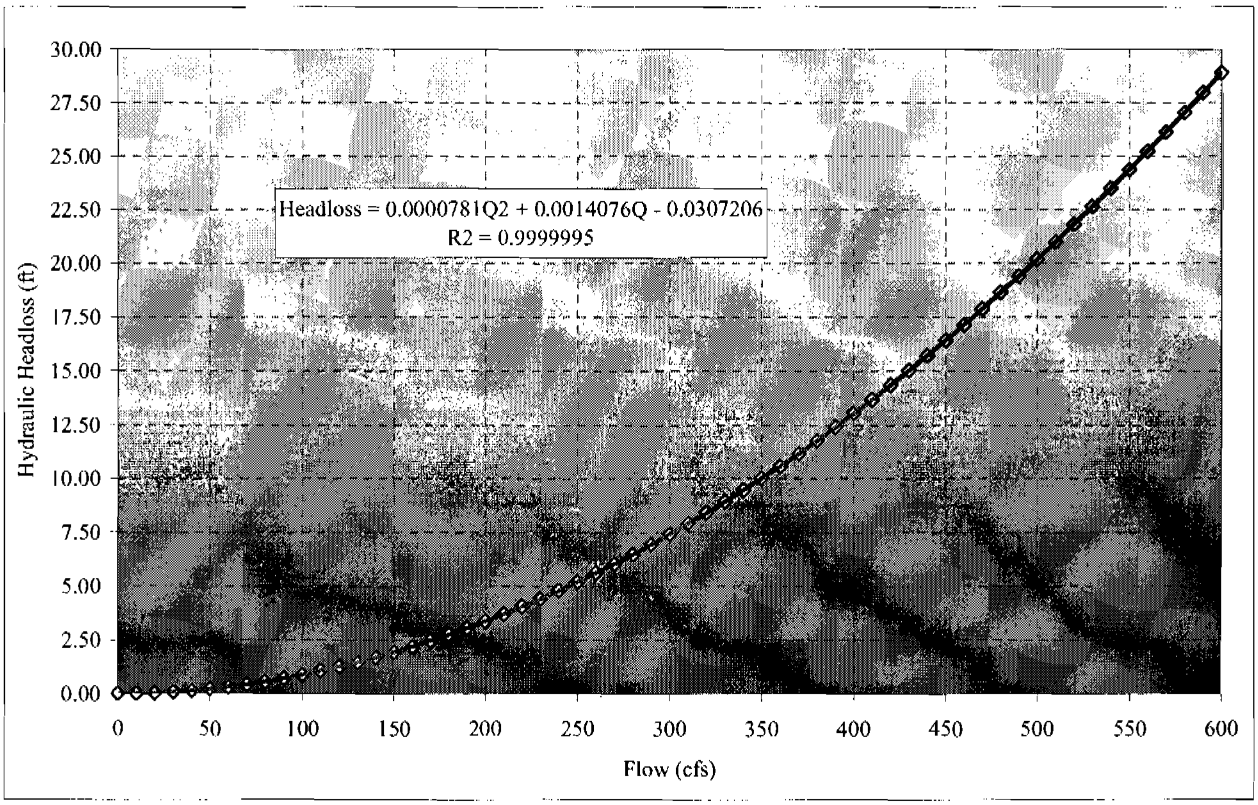
Hydraulic headlosses were estimated for each power plant for the range of flows indicated above and a best-fit polynomial equation relating headloss with flow was derived and input into the model. Table A-4 summarizes the characteristics of the water conveyance system considered for each power plant. Figures A-1 and A-2 graphically depict the friction and form losses calculated for the range of flows indicated above, and the best-fit polynomial equation relating headloss with flow for the proposed Sixth Water and Upper Diamond Fork Hydroelectric Facilities. *(Note: Tables A-20 through A-24, located at the end of the text section of this Attachment A, contains the data from which Figures A-1 and A-2 were derived).*

Figure A-1
Sixth Water Power Station
Hydraulic Headloss vs Flow



Note: Q - Flow in cfs
R - Correlation factor

Figure A-2
Upper Diamond Fork Power Plant - Hydraulic Headloss vs Flow



Note: Q - Flow in cfs
R - Correlation factor

TABLE A-4
Characteristics of Water Conveyance Systems

Description	Internal Diameter (ft)	Lining	Station Start (ft)	Station End (ft)	Length (ft)	Area (ft^2)
Sixth Water						
Inlet Tunnel	10.75	concrete	4,985	7,460	2,475	90.76
Syar Tunnel - 1	8.50	concrete	7,460	37,730	30,270	56.75
Syar Tunnel - 2	8.50	steel liner	37,730	37,874	144	56.75
Sixth Water Pipeline	7.25	steel liner	37,874	42,084	4,242	41.28
Vertical Shaft	7.25	steel liner	42,084	42,127	668	41.28
Syar Tunnel - 3	7.25	steel liner	42,127	45,460	3,333	41.28
Steel Pipe	7.25	steel	45,460	-	150	41.28
Upper Diamond Fork						
Inlet Shaft (at Sixth Water)	9.50	concrete	-	-	30	70.88
Tanner Ridge Tunnel	9.50	concrete	1,027	6,590	5,563	70.88
Sixth Water Pipeline	8.00	steel liner	6,590	12,180	5,590	50.27

Equipment efficiency curves were defined for the turbines and generators. A turbine efficiency curve was defined for each installed capacity considered for the power facilities. Turbine efficiency curves provide the relationship between flow and turbine efficiency and were defined using the computer program TURBNPRO, which is a commercial software program for sizing hydraulic turbines. Each point in the turbine efficiency curve was derived using the CrossPlot function of TURBNPRO by inputing the net head corresponding to the flow within the operating range of the turbine and reading the efficiency corresponding to the turbinable flow. The maximum flow through the turbine was limited to the plant rated flow. The generator efficiency curves defined for the power facilities provide the relationship between turbine output and generator efficiency and are presented in Table A-5. The turbine efficiency curve for the selected optimum installed capacities are shown on Figure A-3 for the Sixth Water Hydroelectric Plant and Figure A-4 for the Upper Diamond Fork Hydroelectric Plant.

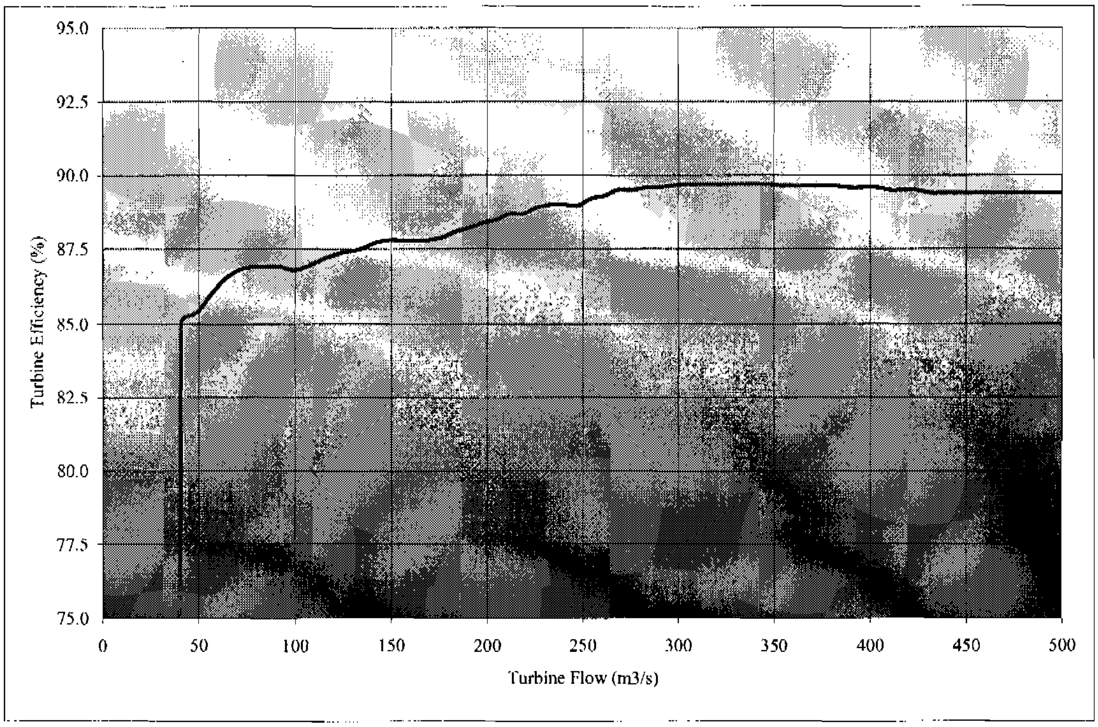
TABLE A-5
Turbine Output vs. Generator Efficiency

Turbine Output (% Rated Output)	Upper Diamond Fork Generator Efficiency (%)	Sixth Water Generator Efficiency (%)
5	95.00	95.00
15	95.26	95.32
20	95.39	95.47
25	95.53	95.63
30	95.66	95.79
35	95.79	95.95
40	95.92	96.11
45	96.05	96.26
50	96.18	96.42
55	96.32	96.58
60	96.45	96.74
65	96.58	96.89
70	96.71	97.05
75	96.84	97.21
80	96.97	97.37
85	97.11	97.53
90	97.24	97.68
95	97.37	97.84
100	97.50	98.00

The transformer efficiency was assumed constant and equal to 99.5% for Sixth Water.

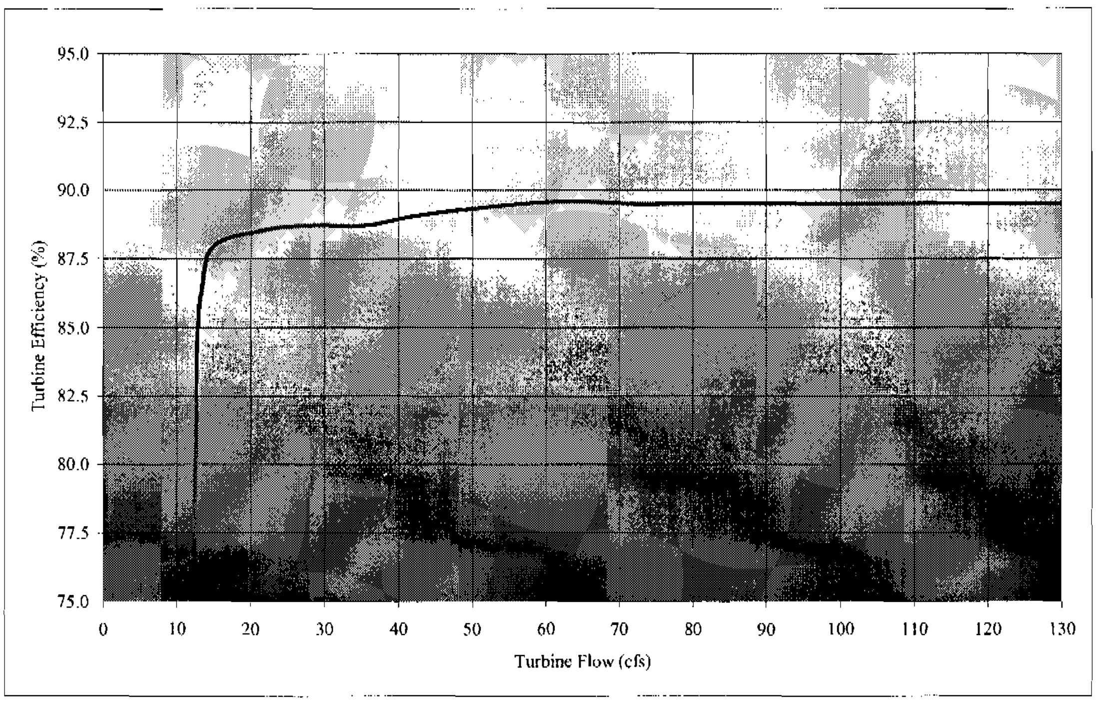
The gross energy was estimated at the high voltage side of the transformer for Sixth Water Power Plant and at the generator terminal for Upper Diamond Fork. No transformer is considered for Upper Diamond Fork.

Figure A-3
Sixth Water Power Station - Turbine Efficiency Curve



Notes : Turbine efficiency curve for the Unit Optimum Installed Capacity
Turbine of the Pelton type, vertical shaft, with four injectors
Minimum turbinable flow approximately 10% of plant rated flow and/or a minimum efficiency of 75%.

Figure A - 4
Upper Diamond Fork Power Station - Turbine Efficiency Curve



Notes : Turbine efficiency curve for the Unit Optimum Installed Capacity of 5,000 kW (plant rated flow of 125 cfs)
Turbine of the Pelton type, horizontal shaft, with two injectors
Minimum turbinable flow approximately 10% of plant rated flow and/or a minimum efficiency of 75%.

Parasitic Load

Generator excitation and other station service consumption losses such as pumping for cooling of bearings, heating, cooling, ventilation, lighting, etc. are drawn from the energy generated by the plant and are generally known as parasitic load. Table A-6 summarizes the criteria used in estimating the parasitic load for the various plants:

TABLE A-6
Criteria for Establishing Parasitic Load

Installed Capacity (IC)	Parasitic Load (% of IC)	Minimum Parasitic Load (kW)	
		Plant in Operation	Plant Out of Service
Up to 20 MW	0.7	30	10
Above 20 MW	0.5	90	20

The energy required for auxiliary systems and lighting when the plants are out of service would be purchased from the electric grid.

Scheduled and Unscheduled Outages

Table A-7 shows the scheduled (programmed maintenance) and unscheduled outages (line tripping, unit tripping, etc.) that have been considered for the various power facilities.

TABLE A-7
Scheduled and Unscheduled Outages

Number of Generating Units	Outages	
	Number of Days	Equivalent Lost Generation (% Gross generation)
1	8	2.2
2 or more	4	1.1

Transmission Line Losses

The transmission line losses were considered for both power facilities from the point of generation to the point of interconnection to the grid (substation or transmission line). Table A-8 summarizes the length, voltage, conductor and/or cable type, and resistance used in estimating the transmission line losses:

TABLE A-8
Criteria for Determining Transmission Line Losses

Power Plant	Interconnection to Grid		Transmission Voltage (kV)	Transmission Line Length (miles)			Resistance (ohms/mile)	
	Point	Owner		Conductor	Cable	Total	Conductor	Cable
Sixth Water	T. Line	UP&L	138	15.5	-	15.5	0.3856	-
Upper Diamond Fork	Sub-station	-	13.8	-	1.5	1.5	-	0.272

Notes:

1) The cable/conductor resistance was selected for the following operating temperatures: cable 20° Celsius; conductor 50° Celsius.
2) Upper Diamond Fork Power Plant interconnects with the substation of Sixth Water Power Plant. The 4/0, 25 kV cable is a stranded aluminum cable with a resistance of 0.0515 ohms per 1000 ft at an operating temperature of 20o Celsius.

SUMMARY

Based on the assumptions and criteria detailed above, the long-term annual average net energy was estimated for each power plant. Table A-9 summarizes the long-term annual average net energy for each power plant. The net energy was estimated at the assumed point of interconnection to CRSP electric grid. Detailed results of the energy analysis are located in Tables A-25, A-26 and A-27 at the back of this attachment.

TABLE A-9
Net Energy Generated (Kilowatt-hours)

Month	Sixth Water (45 MW Plant)	Upper Diamond Fork (5 MW Plant)
October	See footnote[1]	887,668
November	6,764,660	2,897,593
December	3,740,125	1,841,050
January	5,630,533	2,272,205
February	5,865,647	2,289,426
March	4,940,069	2,169,365
April	4,972,873	2,143,837
May	8,807,533	2,882,354
June	14,800,265	3,375,009
July	23,678,890	3,435,885
August	27,897,696	3,396,971
September	27,186,007	3,282,314
TOTAL	**134,269,417**	**30,873,677**

ESTIMATION OF ENERGY BENEFITS

The annual energy benefits were estimated based on the net annual average energy generation (at the assumed point of interconnection to the grid) and an energy tariff of 4.5 cents per kWh. As mentioned above, the energy required for the auxiliary systems and lighting when the plants are out of service would be purchased from the electric grid. In estimating the energy benefits, it was assumed that the electric tariff applied to the energy purchased from the grid would be the same as the sale tariff, i.e., 4.5 cents per kWh. A summary of the estimated annual energy benefits for each plant at each flow rate and associated installed capacity are presented in Table A-10.

[1] The Powerplant would not be operated for generation of electricity when flows through the Powerplant reach a value that is less than 10% of the rated flow for the Powerplant. This condition is described as the parasitic load and the plant would be a user of electricity computed as 20 kw from Table A-6 times 24 hours per day times 31 days in October which equals 14,880 kw of electricity to maintain plant without generating any electricity.

TABLE A-10
Estimation of Net Energy Benefits vs. Installed Capacity

Flow Rate	Installed Capacity	Costs			Benefit	Net Benefits
		Debt Service	O&M	Total		
Sixth Water Power Plant						
100	9,225	$ 540,052	$ 199,923	$ 739,975	$ 2,694,375	$ 1,954,400
200	18,153	$ 684,691	$ 253,468	$ 938,159	$ 4,068,506	$ 3,130,347
300	26,706	$ 838,910	$ 310,558	$1,148,468	$ 5,071,615	$ 3,922,147
400	34,561	$ 1,085,395	$ 401,805	$ 1,487,201	$ 5,706,980	$ 4,219,779
500	41,598	$ 1,190,002	$ 440,530	$ 1,630,532	$ 5,944,304	$ 4,313,772
600	47,904	$ 1,316,465	$ 487,345	$ 1,803,811	$ 5,890,823	$ 4,087,013
Upper Diamond Fork Power Plant						
80	3,175	$178,878	$ 65,109	$ 240,986	$1,007,840	$ 766,853
100	3,995	$ 207,201	$ 76,704	$ 283,906	$1,178,439	$ 894,533
125	5,000	$ 242,853	$ 89,902	$ 332,755	$ 1,360,891	$ 1,028,136

ESTIMATION OF PROJECT IMPLEMENTATION COSTS

Project implementation costs were estimated at the feasibility level based on MWH's cost database for similar size hydroelectric projects. The estimates include construction costs, interest during construction, and Owner's costs such as engineering, administration, insurance, legal, and financing fees. However, the following Owner's costs were not included in the estimates:

- Land acquisition and easements[2];
- Permitting; and
- Planning studies.

CONSTRUCTION COSTS

Construction costs were estimated based on parametric cost analysis and include engineering and construction of the civil works, and procurement, installation, testing, and commissioning of the electrical and mechanical equipment under a turnkey, fixed price contract. Construction costs were broken down into the following items:

- Civil works;
- Electrical and mechanical equipment; and
- Transmission lines and interconnection.

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[2] The right-of-way costs for the proposed Sixth Water Hydroelectric Plant are estimated to be $0 because some of the lands are withdrawn lands located within Forest Service boundaries and any further required lands would either be withdrawn lands or lands granted a special use permit.

The cost of the civil works pertains to the power plant, substation, and bifurcation from the pipeline/aqueduct to the power plant. The selected locations of the proposed power facilities are along existing access roads and it was assumed that no new permanent access roads would be required. Consequently, the cost associated with permanent access roads (if required) was not included in the estimates. The cost of the civil works was estimated assuming the parametric relationship for the civil works (power plant, forebay, and substation) and lump sum amount for the bifurcation shown in Table A-11.

TABLE A-11
Civil Works Cost Criteria

Plant	Powerhouse, Substation, & Forebay	Bifurcation	Powerhouse Back Slope Excavation and Stabilization
Sixth Water	\$80/kw	\$250,000	\$430,000
Upper Diamond Fork	\$80/kw	\$250,000	\$77,000

The cost of the water conveyance system (pipelines or aqueducts), pressure-breaking facilities, programmable logic controllers at the water intakes, and communication links between the intake and pressure breaking facilities are associated with the pipelines/aqueducts to supply water for municipal and industrial needs. Therefore, these costs were not included in the estimates for the power facilities.

The cost of the electrical and mechanical equipment for each power plant was estimated as a water-to-wire package and includes all the electrical and mechanical equipment from the turbine inlet valve to the substation (generating equipment, auxiliary equipment, controls, main step up transformers, high voltage switchgear, etc). The cost estimates include supply, transport, installation, testing, and commissioning. The cost of the water-to-wire package was estimated based on the following parametric relationship derived from regression analysis of cost data obtained from recent bids. In the case of Sixth Water, a lump sum amount of \$70,000 was included for additional disconnect switches to accommodate the incoming line from Upper Diamond Fork Power Plant:

TABLE A-12
Water to Wire Package Cost Criteria

Plant	Cost
Sixth Water	$\$ 716{,}665 * (\text{kVA/rpm})^{0.5537} + \$70{,}000$
Upper Diamond Fork	$\$ 716{,}665 * (\text{kVA/rpm})^{0.5537} + \$100/\text{kW}$

Note: kVA and rpm are the generator rated output and rotational speed, respectively. The reduction of the cost of the water-to-wire package of \$100/kW of installed capacity for Upper Diamond Fork reflects the non-provision of step-up transformer and substation.

The cost of the transmission line and interconnection includes the transmission line from the power plant to the point of interconnection with the electrical grid, including the necessary upgrades of the existing lines, and the required modifications to the interconnection substation to comply with the Utility's requirements. The cost of a new 138 kV switchyard at the junction of UP&L 46 kV and 138 kV lines was also included for Sixth Water power plant. The cost of the power cable from Upper Diamond Fork Hydroelectric Plant to the Sixth Water Hydroelectric Plant substation was not included in the cost estimate for Upper Diamond Fork power plant given that the line was installed with the construction of the Tanner Ridge Tunnel.

The following contingencies were added to the construction costs to reflect the uncertainty of the estimates:

- Civil structures 25%
- Electrical & Mechanical equipment – power plants 25%
- Transmission lines and interconnections 20%

A summary of the construction cost estimates versus the installed capacity is given in Table A-13.

TABLE A-13
Construction Cost Estimate vs. Installed Capacity

Rated Flow (cfs)	Installed Capacity (kW)	Construction Costs			
		Civil Works	E&M Equipment	Transmission & Interconnection	Total
Sixth Water					
100	9,225	$ 1,772,472	$ 4,423,711	$ 4,500,000	$ 10,696,183
200	18,153	$ 2,665,313	$ 6,395,580	$ 4,500,000	$ 13,560,893
300	26,706	$ 3,520,577	$ 8,594,742	$ 4,500,000	$ 16,615,319
400	34,561	$ 4,306,139	$ 12,691,040	$ 4,500,000	$ 21,497,179
500	41,598	$ 5,009,753	$ 14,059,250	$ 4,500,000	$ 23,569,003
600	47,904	$ 5,640,355	$ 15,933,356	$ 4,500,000	$ 26,073,711
Upper Diamond Fork					
80	3,175	$ 538,743	$ 2,944,667	$ 0	$ 3,483,410
100	3,995	$ 620,764	$ 3,483,034	$ 0	$ 4,103,798
125	5,000	$ 721,231	$ 4,088,676	$ 0	$ 4,809,906

Note: Costs are in 2004 US$ and include contingencies

OWNER'S COSTS AND INTEREST DURING CONSTRUCTION (IDC)

The following Owner's costs, expressed in terms of percentage of the total construction cost, were included in the estimates:

- Administration, insurance, legal, financing fees 9%
- Engineering & supervision 6%

A 5.875% interest rate was assumed to calculate the interest during construction. The duration of the construction period was assumed to be 2 years with 60% of the loan disbursed in the first year and 40% on the second year. The total amount of the construction cost was assumed to be debt financed and IDC was calculated assuming the compound interest rate method. Table A-14 summarizes the estimated Owner's costs versus the installed capacity.

TABLE A-14
Estimated Owner's Costs vs. Installed Capacity

Rated Flow (cfs)	Installed Capacity (kW)	Owner's Costs			
		Administration, Insurance, Legal, & Finance Fees	Engineering and Supervision	IDC	Total
Sixth Water Power Plant					
100	9,225	$ 962,656	$ 641,771	$ 1,027,592	$2,632,020
200	18,153	$ 1,220,480	$ 813,654	$ 1,302,808	$ 3,336,942
300	26,706	$ 1,495,379	$ 996,919	$ 1,596,249	$ 4,088,547
400	34,561	$ 1,934,746	$ 1,289,831	$ 2,065,254	$ 5,289,831
500	41,598	$ 2,121,210	$ 1,414,140	$ 2,264,296	$ 5,799,647
600	47,904	$ 2,346,634	$ 1,564,423	$2,504,926	$ 6,415,983
Upper Diamond Fork Power Plant					
80	3,175	$ 313,507	$ 209,005	$ 334,654	$ 857,166
100	3,995	$ 369,342	$ 246,228	$ 394,256	$ 1,009,825
125	5,000	$ 432,892	$ 288,594	$ 462,092	$ 1,183,578

Table A-15 summarizes the project implementation costs estimated for each power plant versus the installed capacity.

TABLE A-15
Estimated Project Implementation Costs vs. Installed Capacity

Rated Flow (cfs)	Installed Capacity (kW)	Project Implementation Cost		
		Construction Cost	Owner's Cost	Total
Sixth Water Power Plant				
100	9,225	$ 10,696,183	$ 2,632,020	$ 13,328,203
200	18,153	$ 13,560,893	$ 3,336,942	$ 16,897,835
300	26,706	$ 16,615,319	$ 4,088,547	$ 20,703,866
400	34,561	$ 21,497,179	$ 5,289,831	$ 26,787,010
500	41,598	$ 23,569,003	$ 5,799,647	$ 29,368,650
600	47,904	$ 26,073,711	$ 6,415,983	$ 32,489,694
Upper Diamond Fork Power Plant				
80	3,175	$ 3,483,410	$ 857,166	$ 4,340,576
100	3,995	$ 4,103,798	$ 1,009,825	$ 5,113,623
125	5,000	$ 4,809,906	$ 1,183,578	$ 5,993,484

OPERATION, MAINTENANCE AND REPLACEMENT COSTS

Annual operation, maintenance and replacement costs (OM&R) were assumed at 1.5% of the total implementation cost (capital cost) and include administration, insurance, routine maintenance, breakdown or emergency maintenance, major repairs and overhauls, spare parts, and capital expenditures throughout the life of the project. Table A-16 summarizes the estimated annual O&M costs.

TABLE A-16
Estimated Annual O&M Costs vs. Installed Capacity

Rated Flow (cfs)	Installed Capacity (kW)	Annual O&M Cost
Sixth Water Power Plant		
100	9,225	$ 199,923
200	18,153	$ 253,468
300	26,706	$ 310,558
400	34,561	$ 401,805
500	41,598	$ 440,530
600	47,904	$ 487,345
Upper Diamond Fork Power Plant		
80	3,175	$ 65,109
100	3,995	$ 76,704
125	5,000	$ 89,902

ECONOMIC ANALYSES

Economic analyses were carried out for each installed capacity. Economic indicators calculated in the economical analyses include the present value of the net benefits (NPV), benefit cost ratio (B/C), cost per kW of installed capacity, and cost per kWh of net energy at the interconnection point to the grid (point of metering).

The following parameters, based upon USBR and other CUP standards, and assumptions were taken into account in the economic analyses:

• Reference year	2004
• Construction period	2004 and 2005
• Commercial operation	January 2006
• Amortization period	50 years
• Annual interest rate for debt service	3.222%
• Duration of construction period	2 years
• Annual Escalation of O&M costs	0%
• Annual Escalation of electric tariff	0%
• Annual interest rate during construction	5.875%
• Equity financing	0%
• Debt financing	100% of total capital cost
• Grace period	2 years
• Discount rate	8%
• Capital cost	presented in Table A-15
• Energy benefits	presented in Table A-10
• Annual OM&R Costs	presented in Table A-16

The disbursement of the total implementation cost (capital cost) was assumed as presented in Table A-17.

TABLE A-17
Disbursement Criteria

Item	Year 1	Year 2
Construction costs	60%	40%
Interest During Construction	Based on construction cost, compound int.	
Administration, Insurance, Legal, & Finance Fees	50%	50%
Engineering and Supervision	50%	50%

The debt service was calculated as annuity payment based on the following formula:

$$\text{Annuity} := C \cdot \left[\frac{i \cdot (1+i)^n}{(1+i)^n - 1} \right]$$

where:

C = Capital cost
i = interest rate
n = amortization period

Annual costs and benefits were calculated for each year of the debt amortization period. However, both the costs and the benefits are constant for each year given that no escalation was considered for the O&M costs or energy tariff. Annual costs include the debt service and the O&M costs while the annual benefits include those from the sale on net energy. The present value of the costs and benefits was calculated by multiplying the annual costs by the corresponding discount factor. The discount factor for each year of the simulation period was calculated based on the following formula:

$$\text{Discount\_factor} := \frac{1}{(1+d)^y}$$

where:

d = discount rate
y = sequence number of year (2004 is the 1st year of the sequence while 2055 is the last, i.e., sequence number 52)

The NPV is the sum of the present value of the net benefits (net benefits = benefits – costs):

$$NPV = \sum \text{(net present value of benefits – net present value of costs)}$$

The benefit/cost ratio is the ratio of the present value of the benefits to the present value of the cost:

$$\frac{B}{C} = \frac{present\_value\_benefits}{present\_value\_costs}$$

The cost per kW of installed capacity is the ratio of the total project cost to the installed capacity while the cost per kWh is the is the ratio of the total project cost to net energy at the interconnection point to the grid.

An economic analysis was performed for each flow rate and installed capacity selected for analysis. A summary of the results are presented in Table A-18, detailed results of the analyses are located in Tables A-28 through A-36. A detailed summary of the economic indicators based on the results of the economic analysis is located in Table A-37 and A-38 at the end of this attachment.

TABLE A-18
Estimated Net Present Value of Project Costs and Benefits

Rated Flow (cfs)	Installed Capacity (kW)	Benefit/Cost Ratio	Net Present Value
Sixth Water Power Plant			
100	9,225	3.64	$ 20,498,218
200	18,153	4.34	$ 32,831,839
300	26,706	4.41	$ 41,136,428
400	34,561	3.84	$ 44,258,063
500	41,598	3.65	$ 45,243,861
600	47,904	3.27	$ 42,865,573
Upper Diamond Fork Power Plant			
80	3,175	4.18	$ 8,042,944
100	3,995	4.15	$ 9,382,082
125	5,000	4.09	$ 10,783,340

SELECTION OF OPTIMUM INSTALLED CAPACITY

The criterion used in selecting the optimum installed capacity was the maximization of the present value of the net benefits (NPV). Figures A-5 and A-6 graphically depict the calculated

NPV's plotted against installed capacity. The highest point on the graph was selected as the optimum installed capacity. Table A-19 summarizes the selected optimum installed capacities and corresponding NPV's.

TABLE A-19
Selected Optimum Installed Capacity

Power Plant	Optimum Installed Capacity (kW)	Net Present Value
Sixth Water	40,000	$ 45,243,861
Upper Diamond Fork	5,000	$ 10,783,340

Note: The installed capacity at upper Diamond is limited by the voltage capacity of the power cable installed in the Tanner Ridge Tunnel.

Figure A-5
Sixth Water Power Station
Net Present Value vs. Installed Capacity

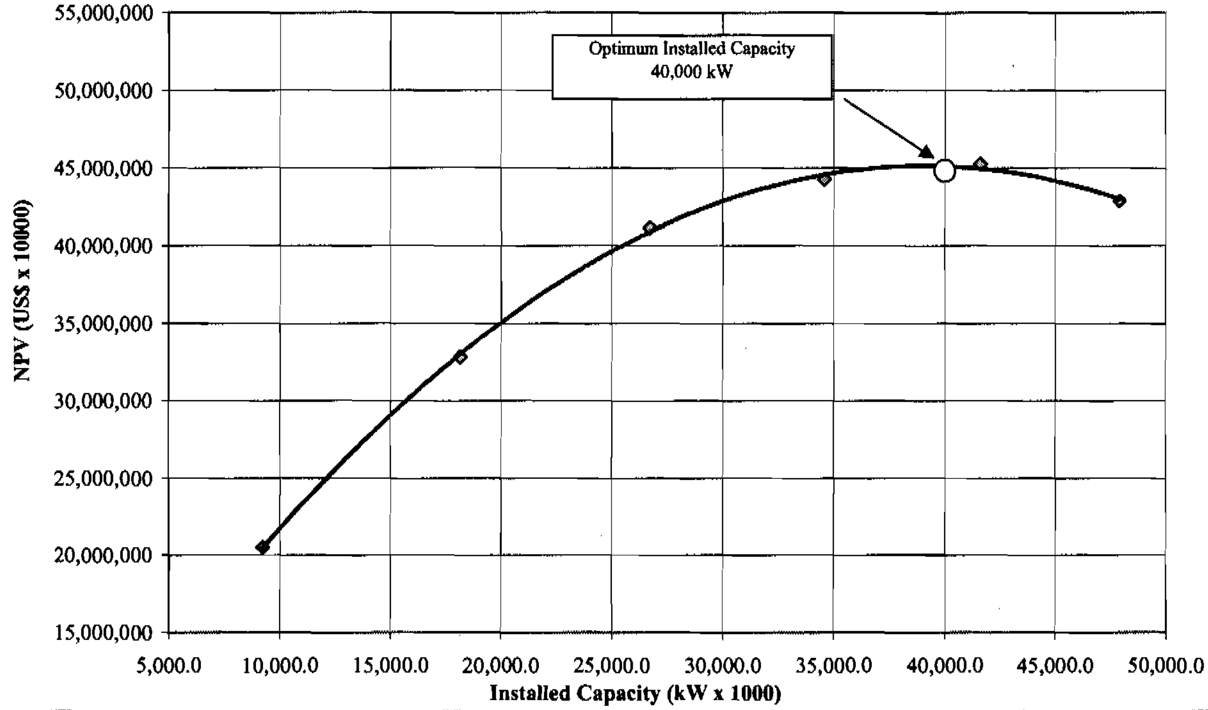

Figure A-6
Upper Diamond Fork Power Station
Net Present Value vs. Installed Capacity

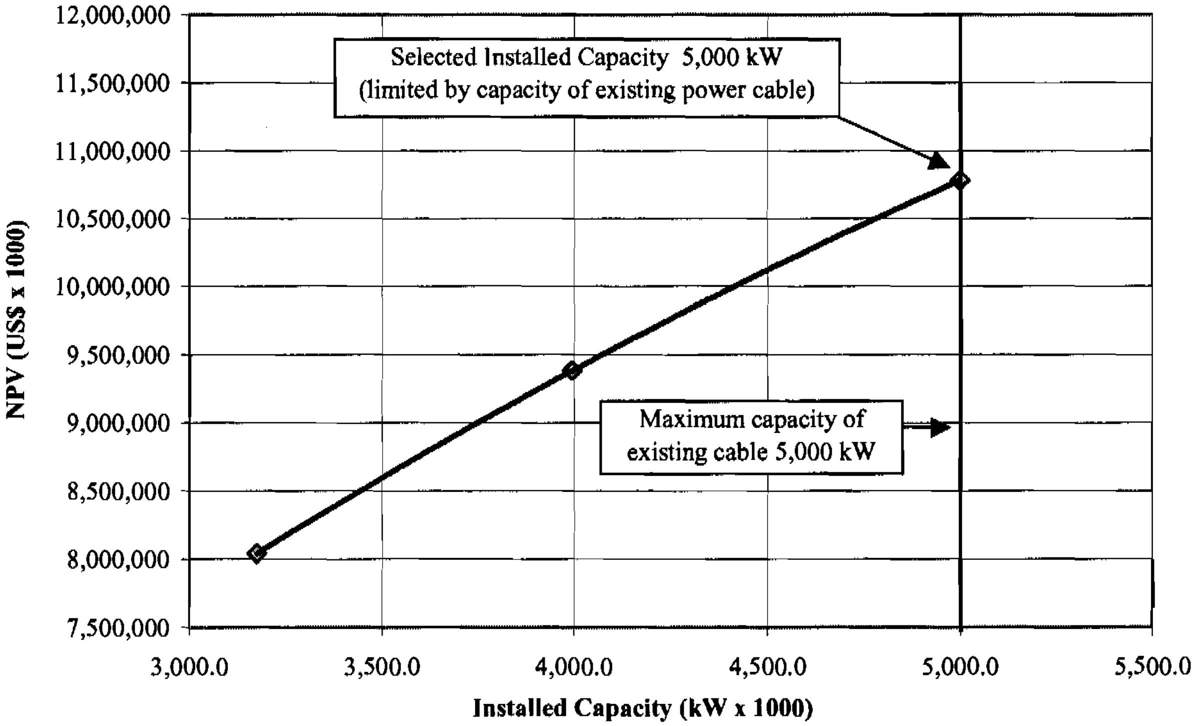

TABLE A-20
Sixth Water Power Plant
Hydraulic Headlosses

Flow (cfs)	Friction Headlosses								Local Headlosses (ft)	Total Headlosses (Friction + Local (ft)
	Inlet Tunnel (ft)	Syar Tunnel-1 (ft)	Syar Tunnel-2 (ft)	Sixth Water Pipeline (ft)	Vertical Shaft (ft)	Syar Tunnel-3 (ft)	Steel Pipe (ft)	Total		
0	0.0000	0.000	0.00000	0.000	0.000	0.000	0.0000	0.00	0.0000	0.000
10	0.0009	0.037	0.00017	0.009	0.001	0.007	0.0003	0.06	0.0023	0.058
20	0.0034	0.139	0.00066	0.033	0.005	0.026	0.0012	0.21	0.0093	0.217
30	0.0075	0.304	0.00145	0.069	0.011	0.054	0.0024	0.45	0.0209	0.470
40	0.0131	0.534	0.00254	0.118	0.019	0.092	0.0042	0.78	0.0371	0.819
50	0.0202	0.827	0.00393	0.178	0.028	0.140	0.0063	1.20	0.0580	1.262
60	0.0288	1.184	0.00563	0.250	0.039	0.197	0.0089	1.71	0.0835	1.797
70	0.0390	1.604	0.00763	0.250	0.039	0.197	0.0089	2.15	0.1136	2.259
80	0.0506	2.088	0.00993	0.430	0.068	0.338	0.0152	3.00	0.1484	3.148
90	0.0638	2.635	0.01253	0.537	0.085	0.422	0.0190	3.77	0.1878	3.962
100	0.0786	3.246	0.01544	0.656	0.103	0.515	0.0232	4.64	0.2319	4.869
110	0.0948	3.920	0.01865	0.786	0.124	0.618	0.0278	5.59	0.2806	5.869
120	0.1126	4.658	0.02216	0.927	0.146	0.729	0.0328	6.63	0.3339	6.961
130	0.1318	5.459	0.02597	1.080	0.170	0.849	0.0382	7.75	0.3919	8.146
140	0.1420	6.324	0.03009	1.244	0.196	0.977	0.0440	8.96	0.4545	9.412
150	0.1750	7.252	0.03450	1.419	0.224	1.115	0.0502	10.27	0.5218	10.792
160	0.1988	8.244	0.03922	1.606	0.253	1.262	0.0568	11.66	0.5936	12.253
170	0.2241	9.300	0.04424	1.804	0.284	1.417	0.0638	13.14	0.6702	13.807
180	0.2510	10.418	0.04956	2.013	0.317	1.581	0.0712	14.70	0.7513	15.452
190	0.2794	11.600	0.05519	2.233	0.352	1.754	0.0790	16.35	0.8371	17.190
200	0.3093	12.846	0.06111	2.464	0.388	1.936	0.0871	18.09	0.9276	19.020
210	0.3408	14.155	0.06734	2.707	0.426	2.127	0.0957	19.92	1.0226	20.942
220	0.3737	15.528	0.07387	2.961	0.466	2.327	0.1047	21.83	1.1223	22.956
230	0.4082	16.964	0.08070	3.226	0.508	2.535	0.1141	23.84	1.2267	25.063
240	0.4442	18.463	0.08783	3.502	0.552	2.752	0.1238	25.92	1.3357	27.260
250	0.4817	20.026	0.09527	3.790	0.597	2.978	0.1340	28.10	1.4493	29.551
260	0.5207	21.653	0.10301	3.502	0.552	2.752	0.1238	29.21	1.5676	30.773
270	0.5613	23.342	0.11104	4.398	0.693	3.456	0.1555	32.72	1.6905	34.407
280	0.6033	25.096	0.11938	4.719	0.743	3.708	0.1669	35.16	1.8180	36.974
290	0.6469	26.912	0.12803	5.051	0.795	3.969	0.1786	37.68	1.9502	39.632
300	0.6920	28.793	0.13697	5.394	0.849	4.238	0.1908	40.29	2.0870	42.382
310	0.7387	30.736	0.14622	5.749	0.905	4.517	0.2033	43.00	2.2285	45.224
320	0.7868	32.743	0.15577	6.114	0.963	4.804	0.2162	45.78	2.3746	48.158
330	0.8365	34.814	0.16562	6.491	1.022	5.100	0.2295	48.66	2.5253	51.184
340	0.8876	36.948	0.17577	6.879	1.083	5.405	0.2432	51.62	2.6807	54.302
350	0.9403	39.145	0.18622	7.278	1.146	5.718	0.2573	54.67	2.8407	57.512
360	0.9945	41.406	0.19698	7.688	1.211	6.040	0.2718	57.81	3.0053	60.813
370	1.0503	43.730	0.20803	8.109	1.277	6.371	0.2867	61.03	3.1746	64.207
380	1.1075	46.118	0.21939	8.541	1.345	6.711	0.3020	64.34	3.3485	67.692

TABLE A-20 (continued)
Sixth Water Power Plant
Hydraulic Headlosses

	Friction Headlosses									
Flow (cfs)	Inlet Tunnel (ft)	Syar Tunnel-1 (ft)	Syar Tunnel-2 (ft)	Sixth Water Pipeline (ft)	Vertical Shaft (ft)	Syar Tunnel-3 (ft)	Steel Pipe (ft)	Total	Local Headlosses (ft)	Total Headlosses (Friction + Local (ft)
390	1.1663	48.569	0.23105	8.985	1.415	7.059	0.3177	67.74	3.5271	71.270
400	1.2266	51.084	0.24301	9.439	1.486	7.417	0.3338	71.23	3.7102	74.940
410	1.2884	53.662	0.25528	9.905	1.560	7.782	0.3502	74.80	3.8981	78.700
420	1.3517	56.303	0.26784	10.382	1.635	8.157	0.3671	78.46	4.0905	82.554
430	1.4165	59.008	0.28071	10.870	1.712	8.540	0.3844	82.21	4.2877	86.499
440	1.4829	61.776	0.29388	11.369	1.790	8.932	0.4020	86.05	4.4894	90.536
450	1.5508	64.608	0.30735	11.879	1.871	9.333	0.4200	89.97	4.6958	94.665
460	1.6202	67.503	0.32113	12.400	1.953	9.743	0.4385	93.98	4.9068	98.885
470	1.6911	70.462	0.33520	12.932	2.036	10.161	0.4573	98.08	5.1225	103.198
480	1.7635	73.484	0.34958	13.476	2.122	10.588	0.4765	102.26	5.3428	107.602
490	1.8375	76.570	0.36426	14.030	2.209	11.024	0.4961	106.53	5.5677	112.098
500	1.9129	79.719	0.37924	14.596	2.298	11.468	0.5161	110.89	5.7973	116.686
510	1.9899	82.931	0.39452	15.173	2.389	11.921	0.5365	115.33	6.0315	121.366
520	2.0684	86.207	0.41010	15.760	2.482	12.383	0.5573	119.87	6.2703	126.138
530	2.1484	89.546	0.42599	16.359	2.576	12.854	0.5785	124.49	6.5138	131.002
540	2.2300	92.949	0.44217	16.969	2.672	13.333	0.6000	129.20	6.7619	135.957
550	2.3130	96.415	0.45866	17.590	2.770	13.821	0.6220	133.99	7.0147	141.005
560	2.3976	99.944	0.47545	18.223	2.870	14.318	0.6444	138.87	7.2721	146.144
570	2.4837	103.537	0.49255	18.866	2.971	14.823	0.6671	143.84	7.5341	151.375
580	2.5713	107.194	0.50994	19.520	3.074	15.337	0.6903	148.90	7.8008	156.698
590	2.6604	110.914	0.52764	20.186	3.179	15.860	0.7138	154.04	8.0721	162.113
600	2.7511	114.697	0.54563	20.862	3.285	16.392	0.7377	159.27	8.3481	167.619

Table A-21
Sixth Water Power Station
Form Losses for Flow of 600 cfs

Item	Station (ft)	Loss Coefficient (K)	Flow (cfs)	Diam 1 (ft)	Diam 2 (ft)	Area 1 (ft2)	Area2 (ft2)	V1 (ft/s)	V2 (ft/s)	V12/2g (ft)	V22/2g (ft)	Headloss (ft)
Trashracks	4,955	1.500	600	-	-	540.00	-	2.22	-	0.08	-	0.11
Intake entrance	4,955	0.750	600	10.75	-	90.76	-	6.61	-	0.67	-	0.50
Gate shaft	7,460	0.750	600	8.50	-	56.75	-	10.57	-	1.71	-	1.28
Contraction no.1 - Transition to Syar Tunnel	7,550	0.150	600	10.75	8.50	90.76	25.88	6.61	23.18	0.67	8.20	1.13
Junction with ventilation shaft	37,225	0.150	600	8.50	-	56.75	-	10.57	-	1.71	-	0.26
Contraction no.2 - Transition to Sixth Water Pipeline	37,874	0.150	600	8.50	7.25	56.75	25.88	10.57	23.18	1.71	8.20	0.97
Pipeline - Vertical bend no.1 (angle = 31 deg)	37,884	0.110	600	7.25	-	41.28	-	14.53	-	3.22	-	0.35
Pipeline - Vertical bend no.2 (angle = 18 deg)	37,900	0.080	600	7.25	-	41.28	-	14.53	-	3.22	-	0.26
Pipeline - Vertical bend no.3 (angle = 3 deg)	38,139	0.014	600	7.25	-	41.28	-	14.53	-	3.22	-	0.05
Pipeline - Vertical bend no.4 (angle = 5 deg)	38,500	0.020	600	7.25	-	41.28	-	14.53	-	3.22	-	0.06
Pipeline - Vertical bend no.5 (angle = 4 deg)	38,700	0.016	600	7.25	-	41.28	-	14.53	-	3.22	-	0.05
Pipeline - Vertical bend no.6 (angle = 10 deg)	38,750	0.040	600	7.25	-	41.28	-	14.53	-	3.22	-	0.13
Pipeline - Vertical bend no.7 (angle = 5 deg)	38,890	0.020	600	7.25	-	41.28	-	14.53	-	3.22	-	0.06
Pipeline - Vertical bend no.8 (angle = 7 deg)	38,890	0.032	600	7.25	-	41.28	-	14.53	-	3.22	-	0.10
Pipeline - Vertical bend no.9 (angle = 12 deg)	39,975	0.050	600	7.25	-	41.28	-	14.53	-	3.22	-	0.16
Pipeline - Vertical bend no.10 (angle = 5 deg)	40,078	0.020	600	7.25	-	41.28	-	14.53	-	3.22	-	0.06
Pipeline - Vertical bend no.11 (angle = 7 deg)	40,272	0.032	600	7.25	-	41.28	-	14.53	-	3.22	-	0.10
Pipeline - Vertical bend no.12 (angle = 1 deg)	40,655	0.006	600	7.25	-	41.28	-	14.53	-	3.22	-	0.02
Pipeline - Vertical bend no.13 (angle = 11 deg)	41,113	0.044	600	7.25	-	41.28	-	14.53	-	3.22	-	0.14
Pipeline - Vertical bend no.14 (angle = 6 deg)	41,220	0.024	600	7.25	-	41.28	-	14.53	-	3.22	-	0.08
Pipeline - Vertical bend no.15 (angle = 5 deg)	41,490	0.020	600	7.25	-	41.28	-	14.53	-	3.22	-	0.06
Pipeline - Vertical bend no.16 (angle = 5 deg)	41,750	0.020	600	7.25	-	41.28	-	14.53	-	3.22	-	0.06
Pipeline - Vertical bend no.17 (angle = 6 deg)	41,925	0.024	600	7.25	-	41.28	-	14.53	-	3.22	-	0.08
Pipeline - Vertical bend no.18 (angle = 90 deg)	42,084	0.200	600	7.25	-	41.28	-	14.53	-	3.22	-	0.64
Pipeline - Vertical bend no.19 (angle = 90 deg)	42,127	0.200	600	7.25	-	41.28	-	14.53	-	3.22	-	0.64
Bifurcation		0.300	600	7.25	3.62	41.28		14.53		3.22	-	0.97
Total												**8.348**

TABLE A-22
Sixth Water Power Plant
Gross and Net Heads

Turbine Elevation (ft)	6,315	
Average Reservoir Elevation (ft)	7,582	
Gross Head (ft)	1,267	
Flow (cfs)	**Hydraulic Headlosses (ft)**	**Net Head (ft)**
10	0.058	1267
20	0.217	1267
30	0.470	1267
40	0.819	1266
50	1.262	1266
60	1.797	1265
70	2.259	1265
80	3.148	1264
90	3.962	1263
100	4.869	1262
110	5.869	1261
120	6.961	1260
130	8.146	1259
140	9.412	1258
150	10.792	1256
160	12.253	1255
170	13.807	1253
180	15.452	1252
190	17.190	1250
200	19.020	1248
210	20.942	1246
220	22.956	1244
230	25.063	1242
240	27.260	1240
250	29.551	1237
260	30.773	1236
270	34.407	1233
280	36.974	1230
290	39.632	1227
300	42.382	1225
310	45.224	1222
320	48.158	1219
330	51.184	1216
340	54.302	1213

TABLE A-22 (continued)
Sixth Water Power Plant
Gross and Net Heads

Flow (cfs)	Hydraulic Headlosses (ft)	Net Head (ft)
350	57.512	1209
360	60.813	1206
370	64.207	1203
380	67.692	1199
390	71.270	1196
400	74.940	1192
410	78.700	1188
420	82.554	1184
430	86.499	1181
440	90.536	1176
450	94.665	1172
460	98.885	1168
470	103.198	1164
480	107.602	1159
490	112.098	1155
500	116.686	1150
510	121.366	1146
520	126.138	1141
530	131.002	1136
540	135.957	1131
550	141.005	1126
560	146.144	1121
570	151.375	1116
580	156.698	1110
590	162.113	1105
600	167.619	1099

TABLE A-23
Upper Diamond Fork Power Plant
Hydraulic Headlosses

Flow (cfs)	Friction Headlosses Inlet Shaft (ft)	Tanner Ridge Tunnel (ft)	Six Water Pipeline (ft)	Total (ft)	Form Headlosses (ft)	Total Headlosses (Friction + Local) (ft)
0	0.0000	0.000	0.000	0.00	0.0000	0.000
10	0.0000	0.004	0.008	0.01	0.0003	0.012
20	0.0001	0.014	0.027	0.04	0.0010	0.042
30	0.0002	0.032	0.056	0.09	0.0022	0.090
40	0.0003	0.055	0.095	0.15	0.0038	0.154
50	0.0005	0.086	0.144	0.23	0.0057	0.235
60	0.0007	0.122	0.202	0.32	0.0081	0.333
70	0.0009	0.166	0.269	0.44	0.0109	0.447
80	0.0012	0.216	0.345	0.56	0.0141	0.576
90	0.0015	0.272	0.431	0.70	0.0176	0.722
100	0.0018	0.335	0.525	0.86	0.0216	0.884
110	0.0022	0.404	0.629	1.04	0.0259	1.061
120	0.0026	0.480	0.741	1.22	0.0306	1.255
130	0.0030	0.563	0.863	1.43	0.0357	1.464
140	0.0035	0.652	0.992	1.65	0.0412	1.689
150	0.0040	0.747	1.131	1.88	0.0471	1.930
160	0.0046	0.849	1.279	2.13	0.0533	2.186
170	0.0052	0.958	1.435	2.40	0.0599	2.458
180	0.0058	1.073	1.600	2.68	0.0670	2.746
190	0.0064	1.194	1.774	2.98	0.0744	3.050
200	0.0071	1.323	1.957	3.29	0.0822	3.369
210	0.0079	1.457	2.148	3.61	0.0903	3.704
220	0.0086	1.598	2.348	3.96	0.0989	4.054
230	0.0094	1.746	2.557	4.31	0.1078	4.420
240	0.0102	1.900	2.774	4.68	0.1171	4.802
250	0.0111	2.061	3.001	5.07	0.1268	5.199
260	0.0120	2.228	3.235	5.48	0.1369	5.612
270	0.0130	2.402	3.479	5.89	0.1473	6.041
280	0.0139	2.582	3.731	6.33	0.1582	6.485
290	0.0149	2.769	3.992	6.78	0.1694	6.945
300	0.0160	2.962	4.261	7.24	0.1810	7.420
310	0.0170	3.162	4.540	7.72	0.1930	7.911
320	0.0182	3.368	4.826	8.21	0.2053	8.418
330	0.0193	3.581	5.122	8.72	0.2180	8.940
340	0.0205	3.800	5.426	9.25	0.2312	9.477

TABLE A-23 (continued)
Upper Diamond Fork Power Plant
Hydraulic Headlosses

Flow (cfs)	Friction Headlosses: Inlet Shaft (ft)	Friction Headlosses: Tanner Ridge Tunnel (ft)	Friction Headlosses: Six Water Pipeline (ft)	Friction Headlosses: Total (ft)	Form Headlosses (ft)	Total Headlosses (Friction + Local) (ft)
350	0.0217	4.026	5.739	9.79	0.2447	10.031
360	0.0230	4.258	6.060	10.34	0.2585	10.599
370	0.0243	4.497	6.390	10.91	0.2728	11.184
380	0.0256	4.742	6.728	11.50	0.2874	11.783
390	0.0269	4.994	7.075	12.10	0.3024	12.399
400	0.0283	5.253	7.431	12.71	0.3178	13.030
410	0.0298	5.518	7.796	13.34	0.3336	13.677
420	0.0312	5.789	8.169	13.99	0.3497	14.339
430	0.0327	6.067	8.550	14.65	0.3663	15.016
440	0.0343	6.351	8.941	15.33	0.3832	15.709
450	0.0358	6.642	9.340	16.02	0.4004	16.418
460	0.0374	6.940	9.747	16.72	0.4181	17.142
470	0.0391	7.244	10.163	17.45	0.4362	17.882
480	0.0407	7.554	10.587	18.18	0.4546	18.637
490	0.0424	7.871	11.021	18.94	0.4734	19.408
500	0.0442	8.195	11.463	19.70	0.4925	20.194
510	0.0460	8.525	11.913	20.48	0.5121	20.996
520	0.0478	8.861	12.372	21.28	0.5320	21.814
530	0.0496	9.205	12.840	22.09	0.5524	22.647
540	0.0515	9.554	13.316	22.92	0.5731	23.495
550	0.0534	9.910	13.801	23.76	0.5941	24.359
560	0.0554	10.273	14.295	24.62	0.6156	25.239
570	0.0574	10.642	14.797	25.50	0.6374	26.133
580	0.0594	11.018	15.308	26.38	0.6596	27.044
590	0.0615	11.400	15.826	27.29	0.6822	27.970
600	0.0636	11.788	16.355	28.21	0.7052	28.912

TABLE A-24
Upper Diamond Power Plant
Gross and Net Heads

Turbine Elevation (ft)		5,730
Average Reservoir Elevation (ft)		6,290
Gross Head (ft)		560
Flow (cfs)	**Hydraulic Headlosses (ft)**	**Net Head (ft)**
0	0.000	560
10	0.012	560
20	0.042	560
30	0.090	560
40	0.154	560
50	0.235	560
60	0.333	560
70	0.447	560
80	0.576	559
90	0.722	559
100	0.884	559
110	1.061	559
120	1.255	559
130	1.464	559

TABLE A-25
Estimated Long-Term Annual Average Energy Production

Power Plant	Rated Flow (cfs)	Installed Capacity (kW)	Alternative	Gross Energy (kWh)	Internal Consumption (kWh)	Outages (kWh)	Transmission Losses (kWh)	Net Energy (kWh)
Sixth Water	100	9,225	Proposed Action	61,983,835	581,528	1,345,804	181,511	59,874,993
	200	128,153		94,083,390	1,144,799	2,037,010	490,331	90,411,250
	300	26,706		117,297,679	1,170,914	2,545,366	878,845	112,702,555
	400	34,561		132,357,242	1,408,158	2,870,538	1,256,773	126,821,773
	500	41,598		138,091,192	1,456,290	2,995,687	1,543,577	132,095,638
	600	47,904		137,030,276	1,535,077	2,970,975	1,617,046	130,907,178
Upper Diamond Fork	80	3,175	Proposed Action	23,357,960	262,973	506,191	192,352	22,396,443
	100	3,995		27,317,447	262,973	592,975	273,966	26,187,533
	125	5,000		31,624,837	312,580	686,296	383,934	30,242,027

TABLE A-26
Sixth Water Power Plant
Annual Maximum Net Capacity and Annual Net Average Energy

Year	Optimum Installed Capacity (cfs)	Plant Rated Flow (cfs)	Maximum Annual Net Capacity (kW)	Annual Average Net Energy
1950			38,694	118,079,003
1951			38,656	103,912,209
1952			35,186	89,274,570
1953			39,142	119,326,885
1954			37,790	116,056,461
1955			39,176	123,144,211
1956			39,086	123,696,995
1957			39,050	111,621,831
1958			38,913	109,707,445
1959			37,851	124,346,071
1960			38,650	128,405,071
1961			38,203	123,934,766
1962			39,094	115,735,982
1963			39,064	119,720,327
1964			38,657	144,167,311
1965			36,001	128,509,692
1966			38,085	145,146,916
1967			38,324	131,420,440
1968			38,404	137,599,193
1969			38,500	123,604,318
1970			39,077	134,613,459
1971			38,000	127,212,499
1972			38,909	145,803,596
1973			38,893	127,633,873
1974			39,046	142,226,247
1975	40,000	476.0	38,430	135,152,603
1976			38,441	144,093,650
1977			38,892	153,005,448
1978			37,766	167,603,768
1979			38,698	170,948,953
1980			38,921	155,054,143
1981			39,059	164,123,158
1982			38,110	120,315,851

TABLE A-26 (continued)
Sixth Water Power Plant
Annual Maximum Net Capacity and Annual Net Average Energy

Year	Optimum Installed Capacity (cfs)	Plant Rated Flow (cfs)	Maximum Annual Net Capacity (kW)	Annual Average Net Energy
1983			33,154	91,072,745
1984			37,097	105,430,645
1985			38,550	92,643,472
1986			38,293	94,744,145
1987			38,642	134,786,197
1988			38,900	139,492,402
1989			38,847	143,878,367
1990			38,349	166,903,623
1991			37,815	148,289,892
1992			38,196	165,727,205
1993			39,101	153,611,839
1994			37,940	154,681,108
1995			38,475	124,720,220
1996			38,289	102,807,633
1997			38,776	120,144,072
1998			38,037	137,748,505
1999			38,433	116,157,271
Average			38,313	130,360,726

Note: The net maximum capacity are estimated at the assumed metering point, i.e., the new 138 kV switchyard that would be constructed at the junction of UP&L 46 kV line with Highway 6.

TABLE A-27
Upper Diamond Fork Power Plant
Annual Maximum Net Capacity and Annual Net Average Energy

Year	Optimum Installated Capacity (cfs)	Plant Rated Flow (cfs)	Maximum Annual Net Capacity (kW)	Annual Average Net Energy (kWh)
1950	5,000	125.0	4,772	25,768,060
1951			4,813	23,916,570
1952			4,836	23,798,407
1953			4,849	26,818,887
1954			4,868	26,550,144
1955			4,885	27,897,660
1956			4,830	26,241,610
1957			4,887	27,428,777
1958			4,887	25,332,481
1959			4,885	27,804,369
1960			4,868	27,840,748
1961			4,886	28,612,851
1962			4,868	25,963,833
1963			4,889	27,536,008
1964			4,886	35,057,267
1965			4,887	32,239,313
1966			4,849	31,778,801
1967			4,869	31,690,611
1968			4,886	33,251,792
1969			4,806	29,538,765
1970			4,885	32,185,837
1971			4,858	28,922,965
1972			4,835	30,914,517
1973			4,831	31,886,149
1974			4,849	32,700,442
1975			4,887	34,429,651
1976			4,816	30,047,430
1977			4,885	31,992,738
1978			4,887	38,678,163
1979			4,889	40,000,824
1980			4,880	38,548,652
1981			4,889	35,692,064
1982			4,849	31,738,922
1983			4,880	24,896,561
1984			4,881	23,610,689
1985			4,844	23,848,986
1986			4,858	23,521,644

TABLE A-27 (continued)
Upper Diamond Fork Power Plant
Annual Maximum Net Capacity and Annual Net Average Energy

Year	Optimum Installated Capacity (cfs)	Plant Rated Flow (cfs)	Maximum Annual Net Capacity (kW)	Annual Average Net Energy (kWh)
1987			4,851	27,743,367
1988			4,885	28,876,293
1989			4,849	30,477,930
1990			4,885	35,337,483
1991			4,880	34,389,405
1992			4,886	35,105,789
1993			4,887	37,365,396
1994			4,886	32,256,000
1995			4,887	33,114,796
1996			4,826	26,047,544
1997			4,850	29,810,619
1998			4,879	34,707,884
1999			4,812	28,185,647
Average			4,863	30,242,027

Note: The net maximum capacity and net energy are estimated at the assumed metering point, i.e., the new 138 kV switchyard that would be constructed at the junction of UP&L 46 kV line with Highway 6 (combined output with Sixth Water power plant).

TABLE A-28
Sixth Water Power Plant Economic Analysis
Q = 100 cfs, Installed Capacity = 9,225 kW

Rated Flow	100 cu ft/s
Rated Net Head	1,250 ft
Rated Installed Capacity	9,225 kW
Synchronous Speed	600 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$11,723,775 (USD)
Total Project Cost	$13,328,203 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	3.64
NPV	20,498,218
US$/KW	1,445
US$/kWh	0.223

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	3	0.7938		540,052	199,923	739,975	2,694,375	1,954,400		428,710	158,705	587,416	2,138,881	1,551,466	1,551,466
2007	4	0.7350		540,052	199,923	739,975	2,694,375	1,954,400		396,954	146,949	543,904	1,980,446	1,436,542	2,988,008
2008	5	0.6806		540,052	199,923	739,975	2,694,375	1,954,400		367,550	136,064	503,614	1,833,746	1,330,132	4,318,140
2009	6	0.6302		540,052	199,923	739,975	2,694,375	1,954,400		340,324	125,985	466,310	1,697,913	1,231,603	5,549,743
2010	7	0.5835		540,052	199,923	739,975	2,694,375	1,954,400		315,115	116,653	431,768	1,572,142	1,140,374	6,690,117
2011	8	0.5403		540,052	199,923	739,975	2,694,375	1,954,400		291,773	108,012	399,785	1,455,687	1,055,901	7,746,018
2012	9	0.5002		540,052	199,923	739,975	2,694,375	1,954,400		270,160	100,011	370,172	1,347,858	977,687	8,723,705
2013	10	0.4632		540,052	199,923	739,975	2,694,375	1,954,400		250,148	92,603	342,751	1,248,017	905,265	9,628,970
2014	11	0.4289		540,052	199,923	739,975	2,694,375	1,954,400		231,619	85,744	317,362	1,155,571	838,209	10,467,179
2015	12	0.3971		540,052	199,923	739,975	2,694,375	1,954,400		214,462	79,392	293,854	1,069,973	776,119	11,243,298
2016	13	0.3677		540,052	199,923	739,975	2,694,375	1,954,400		198,576	73,511	272,087	990,716	718,629	11,961,927
2017	14	0.3405		540,052	199,923	739,975	2,694,375	1,954,400		183,867	68,066	251,933	917,330	665,397	12,627,324
2018	15	0.3152		540,052	199,923	739,975	2,694,375	1,954,400		170,247	63,024	233,271	849,379	616,108	13,243,432
2019	16	0.2919		540,052	199,923	739,975	2,694,375	1,954,400		157,636	58,356	215,992	786,462	570,471	13,813,903
2020	17	0.2703		540,052	199,923	739,975	2,694,375	1,954,400		145,959	54,033	199,992	728,206	528,214	14,342,116
2021	18	0.2502		540,052	199,923	739,975	2,694,375	1,954,400		135,147	50,031	185,178	674,265	489,087	14,831,203

TABLE A-28 (continued)
Sixth Water Power Plant Economic Analysis
Q = 100 cfs, Installed Capacity = 9,225 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2022	19	0.2317		540,052	199,923	739,975	2,694,375	1,954,400		125,136	46,325	171,461	624,319	452,858	15,284,061
2023	20	0.2145		540,052	199,923	739,975	2,694,375	1,954,400		115,867	42,893	158,760	578,073	419,313	15,703,374
2024	21	0.1987		540,052	199,923	739,975	2,694,375	1,954,400		107,284	39,716	147,000	535,253	388,253	16,091,627
2025	22	0.1839		540,052	199,923	739,975	2,694,375	1,954,400		99,337	36,774	136,111	495,605	359,493	16,451,120
2026	23	0.1703		540,052	199,923	739,975	2,694,375	1,954,400		91,979	34,050	126,029	458,893	332,864	16,783,984
2027	24	0.1577		540,052	199,923	739,975	2,694,375	1,954,400		85,166	31,528	116,694	424,901	308,208	17,092,192
2028	25	0.1460		540,052	199,923	739,975	2,694,375	1,954,400		78,857	29,192	108,050	393,427	285,377	17,377,569
2029	26	0.1352		540,052	199,923	739,975	2,694,375	1,954,400		73,016	27,030	100,046	364,284	264,238	17,641,808
2030	27	0.1252		540,052	199,923	739,975	2,694,375	1,954,400		67,607	25,028	92,635	337,300	244,665	17,886,473
2031	28	0.1159		540,052	199,923	739,975	2,694,375	1,954,400		62,599	23,174	85,773	312,315	226,542	18,113,015
2032	29	0.1073		540,052	199,923	739,975	2,694,375	1,954,400		57,962	21,457	79,420	289,181	209,761	18,322,775
2033	30	0.0994		540,052	199,923	739,975	2,694,375	1,954,400		53,669	19,868	73,537	267,760	194,223	18,516,999
2034	31	0.0920		540,052	199,923	739,975	2,694,375	1,954,400		49,693	18,396	68,090	247,926	179,836	18,696,835
2035	32	0.0852		540,052	199,923	739,975	2,694,375	1,954,400		46,012	17,033	63,046	229,561	166,515	18,863,350
2036	33	0.0789		540,052	199,923	739,975	2,694,375	1,954,400		42,604	15,772	58,376	212,556	154,181	19,017,530
2037	34	0.0730		540,052	199,923	739,975	2,694,375	1,954,400		39,448	14,603	54,052	196,811	142,760	19,160,290
2038	35	0.0676		540,052	199,923	739,975	2,694,375	1,954,400		36,526	13,522	50,048	182,233	132,185	19,292,475
2039	36	0.0626		540,052	199,923	739,975	2,694,375	1,954,400		33,821	12,520	46,341	168,734	122,393	19,414,868
2040	37	0.0580		540,052	199,923	739,975	2,694,375	1,954,400		31,315	11,593	42,908	156,235	113,327	19,528,196
2041	38	0.0537		540,052	199,923	739,975	2,694,375	1,954,400		28,996	10,734	39,730	144,662	104,933	19,633,128
2042	39	0.0497		540,052	199,923	739,975	2,694,375	1,954,400		26,848	9,939	36,787	133,947	97,160	19,730,288
2043	40	0.0460		540,052	199,923	739,975	2,694,375	1,954,400		24,859	9,203	34,062	124,025	89,963	19,820,251
2044	41	0.0426		540,052	199,923	739,975	2,694,375	1,954,400		23,018	8,521	31,539	114,838	83,299	19,903,550
2045	42	0.0395		540,052	199,923	739,975	2,694,375	1,954,400		21,313	7,890	29,202	106,331	77,129	19,980,679
2046	43	0.0365		540,052	199,923	739,975	2,694,375	1,954,400		19,734	7,305	27,039	98,455	71,415	20,052,094
2047	44	0.0338		540,052	199,923	739,975	2,694,375	1,954,400		18,272	6,764	25,036	91,162	66,125	20,118,219

TABLE A-28 (continued)
Sixth Water Power Plant Economic Analysis
Q = 100 cfs, Installed Capacity = 9,225 kW

									Present Value						
			Costs						Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2048	45	0.0313		540,052	199,923	739,975	2,694,375	1,954,400		16,919	6,263	23,182	84,409	61,227	20,179,447
2049	46	0.0290		540,052	199,923	739,975	2,694,375	1,954,400		15,665	5,799	21,465	78,157	56,692	20,236,138
2050	47	0.0269		540,052	199,923	739,975	2,694,375	1,954,400		14,505	5,370	19,875	72,367	52,492	20,288,631
2051	48	0.0249		540,052	199,923	739,975	2,694,375	1,954,400		13,431	4,972	18,402	67,007	48,604	20,337,235
2052	49	0.0230		540,052	199,923	739,975	2,694,375	1,954,400		12,436	4,604	17,039	62,043	45,004	20,382,239
2053	50	0.0213		540,052	199,923	739,975	2,694,375	1,954,400		11,515	4,263	15,777	57,447	41,670	20,423,909
2054	51	0.0197		540,052	199,923	739,975	2,694,375	1,954,400		10,662	3,947	14,608	53,192	38,584	20,462,493
2055	52	0.0183		540,052	199,923	739,975	2,694,375	1,954,400		9,872	3,654	13,526	49,252	35,725	20,498,218
								Total	**0**	**5,664,192**	**2,096,841**	**7,761,034**	**28,259,252**		

TABLE A-29
Sixth Water Power Plant Economic Analysis
Q = 200 cfs, Installed Capacity = 18,153 kW

Rated Flow	200 cu ft/s
Rated Net Head	1,250 ft
Rated Installed Capacity	9,225 kW
Synchronous Speed	600 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$14,863,701 (USD)
Total Project Cost	$16,897,835 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	4.34
NPV	32,831,839
US$/KW	931
US$/kWh	0.187

									Present Value						
			Costs						Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	3	0.7938		684,691	253,468	938,159	4,068,506	3,130,347		543,530	201,211	744,741	3,229,711	2,484,971	2,484,971
2007	4	0.7350		684,691	253,468	938,159	4,068,506	3,130,347		503,269	186,306	689,575	2,990,474	2,300,899	4,785,870
2008	5	0.6806		684,691	253,468	938,159	4,068,506	3,130,347		465,989	172,506	638,495	2,768,957	2,130,462	6,916,331
2009	6	0.6302		684,691	253,468	938,159	4,068,506	3,130,347		431,472	159,728	591,199	2,563,849	1,972,650	8,888,981
2010	7	0.5835		684,691	253,468	938,159	4,068,506	3,130,347		399,511	147,896	547,407	2,373,934	1,826,528	10,715,509
2011	8	0.5403		684,691	253,468	938,159	4,068,506	3,130,347		369,917	136,941	506,858	2,198,087	1,691,229	12,406,738
2012	9	0.5002		684,691	253,468	938,159	4,068,506	3,130,347		342,516	126,797	469,313	2,035,266	1,565,953	13,972,691
2013	10	0.4632		684,691	253,468	938,159	4,068,506	3,130,347		317,145	117,405	434,549	1,884,506	1,449,957	15,422,648
2014	11	0.4289		684,691	253,468	938,159	4,068,506	3,130,347		293,652	108,708	402,360	1,744,913	1,342,552	16,765,200
2015	12	0.3971		684,691	253,468	938,159	4,068,506	3,130,347		271,900	100,655	372,556	1,615,660	1,243,104	18,008,304
2016	13	0.3677		684,691	253,468	938,159	4,068,506	3,130,347		251,760	93,199	344,959	1,495,981	1,151,022	19,159,327
2017	14	0.3405		684,691	253,468	938,159	4,068,506	3,130,347		233,111	86,296	319,407	1,385,168	1,065,761	20,225,088
2018	15	0.3152		684,691	253,468	938,159	4,068,506	3,130,347		215,843	79,904	295,747	1,282,563	986,816	21,211,904
2019	16	0.2919		684,691	253,468	938,159	4,068,506	3,130,347		199,855	73,985	273,840	1,187,558	913,719	22,125,623
2020	17	0.2703		684,691	253,468	938,159	4,068,506	3,130,347		185,051	68,504	253,555	1,099,591	846,036	22,971,658

TABLE A-29 (continued)
Sixth Water Power Plant Economic Analysis
Q = 200 cfs, Installed Capacity = 18,153 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2021	18	0.2502		684,691	253,468	938,159	4,068,506	3,130,347		171,343	63,430	234,773	1,018,140	783,366	23,755,025
2022	19	0.2317		684,691	253,468	938,159	4,068,506	3,130,347		158,651	58,731	217,383	942,722	725,339	24,480,364
2023	20	0.2145		684,691	253,468	938,159	4,068,506	3,130,347		146,899	54,381	201,280	872,891	671,610	25,151,974
2024	21	0.1987		684,691	253,468	938,159	4,068,506	3,130,347		136,018	50,353	186,371	808,232	621,862	25,773,836
2025	22	0.1839		684,691	253,468	938,159	4,068,506	3,130,347		125,942	46,623	172,565	748,363	575,798	26,349,634
2026	23	0.1703		684,691	253,468	938,159	4,068,506	3,130,347		116,613	43,169	159,783	692,929	533,146	26,882,780
2027	24	0.1577		684,691	253,468	938,159	4,068,506	3,130,347		107,975	39,972	147,947	641,601	493,654	27,376,433
2028	25	0.1460		684,691	253,468	938,159	4,068,506	3,130,347		99,977	37,011	136,988	594,075	457,087	27,833,520
2029	26	0.1352		684,691	253,468	938,159	4,068,506	3,130,347		92,571	34,269	126,841	550,069	423,228	28,256,749
2030	27	0.1252		684,691	253,468	938,159	4,068,506	3,130,347		85,714	31,731	117,445	509,323	391,878	28,648,627
2031	28	0.1159		684,691	253,468	938,159	4,068,506	3,130,347		79,365	29,380	108,745	471,596	362,850	29,011,477
2032	29	0.1073		684,691	253,468	938,159	4,068,506	3,130,347		73,486	27,204	100,690	436,663	335,972	29,347,449
2033	30	0.0994		684,691	253,468	938,159	4,068,506	3,130,347		68,043	25,189	93,232	404,317	311,086	29,658,535
2034	31	0.0920		684,691	253,468	938,159	4,068,506	3,130,347		63,003	23,323	86,326	374,368	288,042	29,946,577
2035	32	0.0852		684,691	253,468	938,159	4,068,506	3,130,347		58,336	21,595	79,931	346,637	266,706	30,213,283
2036	33	0.0789		684,691	253,468	938,159	4,068,506	3,130,347		54,015	19,996	74,010	320,960	246,950	30,460,233
2037	34	0.0730		684,691	253,468	938,159	4,068,506	3,130,347		50,013	18,515	68,528	297,185	228,657	30,688,890
2038	35	0.0676		684,691	253,468	938,159	4,068,506	3,130,347		46,309	17,143	63,452	275,172	211,720	30,900,609
2039	36	0.0626		684,691	253,468	938,159	4,068,506	3,130,347		42,879	15,873	58,752	254,788	196,037	31,096,646
2040	37	0.0580		684,691	253,468	938,159	4,068,506	3,130,347		39,702	14,697	54,400	235,915	181,515	31,278,162
2041	38	0.0537		684,691	253,468	938,159	4,068,506	3,130,347		36,761	13,609	50,370	218,440	168,070	31,446,231
2042	39	0.0497		684,691	253,468	938,159	4,068,506	3,130,347		34,038	12,601	46,639	202,259	155,620	31,601,852
2043	40	0.0460		684,691	253,468	938,159	4,068,506	3,130,347		31,517	11,667	43,184	187,277	144,093	31,745,945
2044	41	0.0426		684,691	253,468	938,159	4,068,506	3,130,347		29,182	10,803	39,985	173,405	133,419	31,879,364
2045	42	0.0395		684,691	253,468	938,159	4,068,506	3,130,347		27,021	10,003	37,024	160,560	123,536	32,002,900

TABLE A-29 (continued)
Sixth Water Power Plant Economic Analysis
Q = 200 cfs, Installed Capacity = 18,153 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2046	43	0.0365		684,691	253,468	938,159	4,068,506	3,130,347		25,019	9,262	34,281	148,667	114,386	32,117,286
2047	44	0.0338		684,691	253,468	938,159	4,068,506	3,130,347		23,166	8,576	31,742	137,654	105,913	32,223,198
2048	45	0.0313		684,691	253,468	938,159	4,068,506	3,130,347		21,450	7,941	29,391	127,458	98,067	32,321,265
2049	46	0.0290		684,691	253,468	938,159	4,068,506	3,130,347		19,861	7,352	27,213	118,016	90,803	32,412,068
2050	47	0.0269		684,691	253,468	938,159	4,068,506	3,130,347		18,390	6,808	25,198	109,274	84,077	32,496,145
2051	48	0.0249		684,691	253,468	938,159	4,068,506	3,130,347		17,028	6,304	23,331	101,180	77,849	32,573,994
2052	49	0.0230		684,691	253,468	938,159	4,068,506	3,130,347		15,766	5,837	21,603	93,685	72,082	32,646,076
2053	50	0.0213		684,691	253,468	938,159	4,068,506	3,130,347		14,598	5,404	20,003	86,746	66,743	32,712,819
2054	51	0.0197		684,691	253,468	938,159	4,068,506	3,130,347		13,517	5,004	18,521	80,320	61,799	32,774,618
2055	52	0.0183		684,691	253,468	938,159	4,068,506	3,130,347		12,516	4,633	17,149	74,370	57,221	32,831,839
								Total	**0**	**7,181,207**	**2,658,429**	**9,839,636**	**42,671,475**		

Note: Assumptions
Construction Period – 2 years
Interest rate during construction (for IDC estimate) – 5.875%

TABLE A-30
Sixth Water Power Plant Economic Analysis
Q = 300 cfs, Installed Capacity = 26,706 kW

Rated Flow	300 cu ft/s
Rated Net Head	1,212 ft
Rated Installed Capacity	26,706 kW
Synchronous Speed	514 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$18,211,568 (USD)
Total Project Cost	$20,703,866 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	4.41
NPV	41,136,428
US$/KW	775
US$/kWh	0.184

		Costs							Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	3	0.7938		838,910	310,558	1,149,468	5,071,615	3,922,147		665,954	246,531	912,484	4,026,011	3,113,527	3,113,527
2007	4	0.7350		838,910	310,558	1,149,468	5,071,615	3,922,147		616,624	228,269	844,893	3,727,788	2,882,895	5,996,422
2008	5	0.6806		838,910	310,558	1,149,468	5,071,615	3,922,147		570,948	211,361	782,308	3,451,656	2,669,348	8,665,770
2009	6	0.6302		838,910	310,558	1,149,468	5,071,615	3,922,147		528,655	195,704	724,360	3,195,978	2,471,618	11,137,388
2010	7	0.5835		838,910	310,558	1,149,468	5,071,615	3,922,147		489,496	181,208	670,703	2,959,239	2,288,535	13,425,923
2011	8	0.5403		838,910	310,558	1,149,468	5,071,615	3,922,147		453,237	167,785	621,022	2,740,036	2,119,014	15,544,938
2012	9	0.5002		838,910	310,558	1,149,468	5,071,615	3,922,147		419,664	155,356	575,020	2,537,070	1,962,050	17,506,988
2013	10	0.4632		838,910	310,558	1,149,468	5,071,615	3,922,147		388,577	143,848	532,426	2,349,139	1,816,713	19,323,701
2014	11	0.4289		838,910	310,558	1,149,468	5,071,615	3,922,147		359,794	133,193	492,987	2,175,129	1,682,142	21,005,843
2015	12	0.3971		838,910	310,558	1,149,468	5,071,615	3,922,147		333,143	123,327	456,469	2,014,008	1,557,539	22,563,381
2016	13	0.3677		838,910	310,558	1,149,468	5,071,615	3,922,147		308,465	114,192	422,657	1,864,822	1,442,165	24,005,547
2017	14	0.3405		838,910	310,558	1,149,468	5,071,615	3,922,147		285,616	105,733	391,349	1,726,687	1,335,338	25,340,885
2018	15	0.3152		838,910	310,558	1,149,468	5,071,615	3,922,147		264,459	97,901	362,360	1,598,785	1,236,424	26,577,309
2019	16	0.2919		838,910	310,558	1,149,468	5,071,615	3,922,147		244,870	90,649	335,519	1,480,356	1,144,837	27,722,147
2020	17	0.2703		838,910	310,558	1,149,468	5,071,615	3,922,147		226,731	83,934	310,665	1,370,700	1,060,035	28,782,182

TABLE A-30 (continued)
Sixth Water Power Plant Economic Analysis
Q = 300 cfs, Installed Capacity = 26,706 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2021	18	0.2502		838,910	310,558	1,149,468	5,071,615	3,922,147		209,936	77,717	287,653	1,269,167	981,514	29,763,695
2022	19	0.2317		838,910	310,558	1,149,468	5,071,615	3,922,147		194,385	71,960	266,346	1,175,154	908,809	30,672,504
2023	20	0.2145		838,910	310,558	1,149,468	5,071,615	3,922,147		179,987	66,630	246,616	1,088,106	841,490	31,513,994
2024	21	0.1987		838,910	310,558	1,149,468	5,071,615	3,922,147		166,654	61,694	228,348	1,007,505	779,157	32,293,151
2025	22	0.1839		838,910	310,558	1,149,468	5,071,615	3,922,147		154,309	57,124	211,434	932,875	721,442	33,014,592
2026	23	0.1703		838,910	310,558	1,149,468	5,071,615	3,922,147		142,879	52,893	195,772	863,774	668,002	33,682,594
2027	24	0.1577		838,910	310,558	1,149,468	5,071,615	3,922,147		132,295	48,975	181,270	799,790	618,520	34,301,114
2028	25	0.1460		838,910	310,558	1,149,468	5,071,615	3,922,147		122,496	45,347	167,843	740,547	572,704	34,873,818
2029	26	0.1352		838,910	310,558	1,149,468	5,071,615	3,922,147		113,422	41,988	155,410	685,691	530,281	35,404,099
2030	27	0.1252		838,910	310,558	1,149,468	5,071,615	3,922,147		105,020	38,878	143,898	634,899	491,001	35,895,100
2031	28	0.1159		838,910	310,558	1,149,468	5,071,615	3,922,147		97,241	35,998	133,239	587,870	454,631	36,349,731
2032	29	0.1073		838,910	310,558	1,149,468	5,071,615	3,922,147		90,038	33,331	123,370	544,324	420,954	36,770,685
2033	30	0.0994		838,910	310,558	1,149,468	5,071,615	3,922,147		83,369	30,862	114,231	504,004	389,773	37,160,458
2034	31	0.0920		838,910	310,558	1,149,468	5,071,615	3,922,147		77,193	28,576	105,769	466,670	360,900	37,521,358
2035	32	0.0852		838,910	310,558	1,149,468	5,071,615	3,922,147		71,475	26,460	97,935	432,102	334,167	37,855,525
2036	33	0.0789		838,910	310,558	1,149,468	5,071,615	3,922,147		66,181	24,500	90,680	400,094	309,414	38,164,939
2037	34	0.0730		838,910	310,558	1,149,468	5,071,615	3,922,147		61,278	22,685	83,963	370,458	286,494	38,451,434
2038	35	0.0676		838,910	310,558	1,149,468	5,071,615	3,922,147		56,739	21,004	77,744	343,016	265,273	38,716,707
2039	36	0.0626		838,910	310,558	1,149,468	5,071,615	3,922,147		52,536	19,449	71,985	317,608	245,623	38,962,329
2040	37	0.0580		838,910	310,558	1,149,468	5,071,615	3,922,147		48,645	18,008	66,653	294,081	227,429	39,189,758
2041	38	0.0537		838,910	310,558	1,149,468	5,071,615	3,922,147		45,041	16,674	61,715	272,297	210,582	39,400,340
2042	39	0.0497		838,910	310,558	1,149,468	5,071,615	3,922,147		41,705	15,439	57,144	252,127	194,983	39,595,323
2043	40	0.0460		838,910	310,558	1,149,468	5,071,615	3,922,147		38,616	14,295	52,911	233,451	180,540	39,775,863
2044	41	0.0426		838,910	310,558	1,149,468	5,071,615	3,922,147		35,755	13,236	48,992	216,158	167,167	39,943,030
2045	42	0.0395		838,910	310,558	1,149,468	5,071,615	3,922,147		33,107	12,256	45,363	200,147	154,784	40,097,814

TABLE A-30 (continued)
Sixth Water Power Plant Economic Analysis
Q = 300 cfs, Installed Capacity = 26,706 kW

			Costs						Present Value							
									Costs							
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2046	43	0.0365		838,910	310,558	1,149,468	5,071,615	3,922,147		30,654	11,348	42,003	185,321	143,319	40,241,133
2047	44	0.0338		838,910	310,558	1,149,468	5,071,615	3,922,147		28,384	10,507	38,891	171,594	132,702	40,373,835
2048	45	0.0313		838,910	310,558	1,149,468	5,071,615	3,922,147		26,281	9,729	36,010	158,883	122,873	40,496,708
2049	46	0.0290		838,910	310,558	1,149,468	5,071,615	3,922,147		24,335	9,008	33,343	147,114	113,771	40,610,478
2050	47	0.0269		838,910	310,558	1,149,468	5,071,615	3,922,147		22,532	8,341	30,873	136,217	105,343	40,715,822
2051	48	0.0249		838,910	310,558	1,149,468	5,071,615	3,922,147		20,863	7,723	28,586	126,126	97,540	40,813,362
2052	49	0.0230		838,910	310,558	1,149,468	5,071,615	3,922,147		19,318	7,151	26,469	116,784	90,315	40,903,677
2053	50	0.0213		838,910	310,558	1,149,468	5,071,615	3,922,147		17,887	6,621	24,508	108,133	83,625	40,987,302
2054	51	0.0197		838,910	310,558	1,149,468	5,071,615	3,922,147		16,562	6,131	22,693	100,123	77,431	41,064,733
2055	52	0.0183		838,910	310,558	1,149,468	5,071,615	3,922,147		15,335	5,677	21,012	92,707	71,695	41,136,428
								Total	**0**	**8,798,687**	**3,257,207**	**12,055,894**	**53,192,321**		

Note: Assumptions
Construction period – 2 years
Interest rate during construction (for IDC estimate) – 5.875%

TABLE A-31
Sixth Water Power Plant Economic Analysis
Q = 400 cfs, Installed Capacity = 34,561 kW

Rated Flow	400 cu ft/s
Rated Net Head	1,180 ft
Rated Installed Capacity	34,561 kW
Synchronous Speed	327 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$23,562,433 (USD)
Total Project Cost	$26,787,010 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	3.84
NPV	44,258,063
US$/KW	775
US$/kWh	0.211

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	3	0.7938		1,085,395	401,805	1,487,201	5,706,980	4,219,779		861,622	318,966	1,180,588	4,530,385	3,349,797	3,349,797
2007	4	0.7350		1,085,395	401,805	1,487,201	5,706,980	4,219,779		797,798	295,339	1,093,137	4,194,801	3,101,664	6,451,461
2008	5	0.6806		1,085,395	401,805	1,487,201	5,706,980	4,219,779		738,702	273,462	1,012,164	3,884,075	2,871,911	9,323,371
2009	6	0.6302		1,085,395	401,805	1,487,201	5,706,980	4,219,779		683,983	253,205	937,189	3,596,365	2,659,177	11,982,548
2010	7	0.5835		1,085,395	401,805	1,487,201	5,706,980	4,219,779		633,318	234,449	867,767	3,329,968	2,462,201	14,444,749
2011	8	0.5403		1,085,395	401,805	1,487,201	5,706,980	4,219,779		586,405	217,083	803,488	3,083,304	2,279,815	16,724,564
2012	9	0.5002		1,085,395	401,805	1,487,201	5,706,980	4,219,779		542,968	201,003	743,971	2,854,911	2,110,940	18,835,504
2013	10	0.4632		1,085,395	401,805	1,487,201	5,706,980	4,219,779		502,748	186,114	688,862	2,643,436	1,954,574	20,790,079
2014	11	0.4289		1,085,395	401,805	1,487,201	5,706,980	4,219,779		465,507	172,327	637,835	2,447,626	1,809,791	22,599,870
2015	12	0.3971		1,085,395	401,805	1,487,201	5,706,980	4,219,779		431,025	159,562	590,588	2,266,320	1,675,732	24,275,602
2016	13	0.3677		1,085,395	401,805	1,487,201	5,706,980	4,219,779		399,098	147,743	546,841	2,098,445	1,551,604	25,827,206
2017	14	0.3405		1,085,395	401,805	1,487,201	5,706,980	4,219,779		369,535	136,799	506,334	1,943,004	1,436,670	27,263,877
2018	15	0.3152		1,085,395	401,805	1,487,201	5,706,980	4,219,779		342,162	126,666	468,828	1,799,078	1,330,250	28,594,127
2019	16	0.2919		1,085,395	401,805	1,487,201	5,706,980	4,219,779		316,817	117,283	434,100	1,665,813	1,231,713	29,825,840
2020	17	0.2703		1,085,395	401,805	1,487,201	5,706,980	4,219,779		293,349	108,595	401,944	1,542,419	1,140,475	30,966,316

TABLE A-31 (continued)
Sixth Water Power Plant Economic Analysis
Q = 400 cfs, Installed Capacity = 34,561 kW

			Costs						Present Value						
									Costs						
Year	Sequeuce No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2021	18	0.2502		1,085,395	401,805	1,487,201	5,706,980	4,219,779		271,619	100,551	372,170	1,428,166	1,055,996	32,022,311
2022	19	0.2317		1,085,395	401,805	1,487,201	5,706,980	4,219,779		251,499	93,103	344,602	1,322,376	977,774	33,000,085
2023	20	0.2145		1,085,395	401,805	1,487,201	5,706,980	4,219,779		232,870	86,207	319,076	1,224,422	905,346	33,905,431
2024	21	0.1987		1,085,395	401,805	1,487,201	5,706,980	4,219,779		215,620	79,821	295,441	1,133,724	838,283	34,743,715
2025	22	0.1839		1,085,395	401,805	1,487,201	5,706,980	4,219,779		199,648	73,908	273,556	1,049,745	776,188	35,519,903
2026	23	0.1703		1,085,395	401,805	1,487,201	5,706,980	4,219,779		184,859	68,434	253,293	971,986	718,693	36,238,596
2027	24	0.1577		1,085,395	401,805	1,487,201	5,706,980	4,219,779		171,166	63,364	234,531	899,987	665,456	36,904,052
2028	25	0.1460		1,085,395	401,805	1,487,201	5,706,980	4,219,779		158,487	58,671	217,158	833,321	616,163	37,520,215
2029	26	0.1352		1,085,395	401,805	1,487,201	5,706,980	4,219,779		146,747	54,325	201,072	771,594	570,522	38,090,737
2030	27	0.1252		1,085,395	401,805	1,487,201	5,706,980	4,219,779		135,877	50,301	186,178	714,439	528,261	38,618,998
2031	28	0.1159		1,085,395	401,805	1,487,201	5,706,980	4,219,779		125,812	46,575	172,387	661,517	489,130	39,108,128
2032	29	0.1073		1,085,395	401,805	1,487,201	5,706,980	4,219,779		116,493	43,125	159,618	612,516	452,898	39,561,027
2033	30	0.0994		1,085,395	401,805	1,487,201	5,706,980	4,219,779		107,864	39,930	147,794	567,144	419,350	39,980,377
2034	31	0.0920		1,085,395	401,805	1,487,201	5,706,980	4,219,779		99,874	36,973	136,846	525,134	388,287	40,368,664
2035	32	0.0852		1,085,395	401,805	1,487,201	5,706,980	4,219,779		92,476	34,234	126,710	486,235	359,525	40,728,190
2036	33	0.0789		1,085,395	401,805	1,487,201	5,706,980	4,219,779		85,626	31,698	117,324	450,218	332,894	41,061,084
2037	34	0.0730		1,085,395	401,805	1,487,201	5,706,980	4,219,779		79,283	29,350	108,633	416,868	308,235	41,369,319
2038	35	0.0676		1,085,395	401,805	1,487,201	5,706,980	4,219,779		73,410	27,176	100,586	385,989	285,403	41,654,722
2039	36	0.0626		1,085,395	401,805	1,487,201	5,706,980	4,219,779		67,972	25,163	93,135	357,397	264,262	41,918,983
2040	37	0.0580		1,085,395	401,805	1,487,201	5,706,980	4,219,779		62,937	23,299	86,236	330,923	244,687	42,163,670
2041	38	0.0537		1,085,395	401,805	1,487,201	5,706,980	4,219,779		58,275	21,573	79,849	306,410	226,562	42,390,232
2042	39	0.0497		1,085,395	401,805	1,487,201	5,706,980	4,219,779		53,959	19,975	73,934	283,713	209,780	42,600,012
2043	40	0.0460		1,085,395	401,805	1,487,201	5,706,980	4,219,779		49,962	18,495	68,457	262,698	194,240	42,794,252
2044	41	0.0426		1,085,395	401,805	1,487,201	5,706,980	4,219,779		46,261	17,125	63,386	243,239	179,852	42,974,105
2045	42	0.0395		1,085,395	401,805	1,487,201	5,706,980	4,219,779		42,834	15,857	58,691	225,221	166,530	43,140,634
2046	43	0.0365		1,085,395	401,805	1,487,201	5,706,980	4,219,779		39,661	14,682	54,344	208,538	154,194	43,294,829

TABLE A-31 (continued)
Sixth Water Power Plant Economic Analysis
Q = 400 cfs, Installed Capacity = 34,561 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2047	44	0.0338		1,085,395	401,805	1,487,201	5,706,980	4,219,779		36,723	13,595	50,318	193,091	142,772	43,437,601
2048	45	0.0313		1,085,395	401,805	1,487,201	5,706,980	4,219,779		34,003	12,588	46,591	178,788	132,197	43,569,798
2049	46	0.0290		1,085,395	401,805	1,487,201	5,706,980	4,219,779		31,484	11,655	43,140	165,544	122,404	43,692,202
2050	47	0.0269		1,085,395	401,805	1,487,201	5,706,980	4,219,779		29,152	10,792	39,944	153,282	113,337	43,805,540
2051	48	0.0249		1,085,395	401,805	1,487,201	5,706,980	4,219,779		26,993	9,993	36,985	141,927	104,942	43,910,482
2052	49	0.0230		1,085,395	401,805	1,487,201	5,706,980	4,219,779		24,993	9,252	34,246	131,414	97,169	44,007,650
2053	50	0.0213		1,085,395	401,805	1,487,201	5,706,980	4,219,779		23,142	8,567	31,709	121,680	89,971	44,097,621
2054	51	0.0197		1,085,395	401,805	1,487,201	5,706,980	4,219,779		21,428	7,932	29,360	112,667	83,306	44,180,927
2055	52	0.0183		1,085,395	401,805	1,487,201	5,706,980	4,219,779		19,841	7,345	27,185	104,321	77,136	44,258,063
								Total	**0**	**11,383,889**	**4,214,229**	**15,598,118**	**59,856,181**		

Note: Assumptions

Construction period - 2 years.
Interest rate during construction (for IDC estimate) - 5.875%

TABLE A-32
Sixth Water Power Plant Economic Analysis
Q = 500 cfs, Installed Capacity = 41,598 kW

Rated Flow	500 cu ft/s
Rated Net Head	1,138 ft
Rated Installed Capacity	41,598 kW
Synchronous Speed	327 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$25,833,299 (USD)
Total Project Cost	$29,368,650 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	3.65
NPV	45,243,881
US$/KW	706
US$/kWh	0.222

									Present Value						
			Costs						Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0		0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0		0	0
2006	3	0.7938		1,190,002	440,530	1,630,532	5,944,304	4,313,772		944,662	349,707	1,294,369	4,718,780	3,424,411	3,424,411
2007	4	0.7350		1,190,002	440,530	1,630,532	5,944,304	4,313,772		874,687	323,803	1,198,490	4,369,241	3,170,751	6,595,162
2008	5	0.6806		1,190,002	440,530	1,630,532	5,944,304	4,313,772		809,895	299,817	1,109,713	4,045,593	2,935,881	9,531,043
2009	6	0.6302		1,190,002	440,530	1,630,532	5,944,304	4,313,772		749,903	277,608	1,027,512	3,745,920	2,718,408	12,249,451
2010	7	0.5835		1,190,002	440,530	1,630,532	5,944,304	4,313,772		694,355	257,045	951,400	3,468,444	2,517,044	14,766,496
2011	8	0.5403		1,190,002	440,530	1,630,532	5,944,304	4,313,772		642,921	238,005	880,926	3,211,522	2,330,597	17,097,092
2012	9	0.5002		1,190,002	440,530	1,630,532	5,944,304	4,313,772		595,297	220,375	815,672	2,973,632	2,157,960	19,255,052
2013	10	0.4632		1,190,002	440,530	1,630,532	5,944,304	4,313,772		551,201	204,051	755,252	2,753,363	1,998,111	21,253,163
2014	11	0.4289		1,190,002	440,530	1,630,532	5,944,304	4,313,772		510,371	188,936	699,307	2,549,410	1,850,103	23,103,266
2015	12	0.3971		1,190,002	440,530	1,630,532	5,944,304	4,313,772		472,566	174,940	647,507	2,360,565	1,713,058	24,816,324
2016	13	0.3677		1,190,002	440,530	1,630,532	5,944,304	4,313,772		437,561	161,982	599,543	2,185,708	1,586,165	26,402,489
2017	14	0.3405		1,190,002	440,530	1,630,532	5,944,304	4,313,772		405,149	149,983	555,133	2,023,804	1,468,671	27,871,161
2018	15	0.3152		1,190,002	440,530	1,630,532	5,944,304	4,313,772		375,138	138,873	514,012	1,873,892	1,359,881	29,231,041
2019	16	0.2919		1,190,002	440,530	1,630,532	5,944,304	4,313,772		347,350	128,586	475,937	1,735,086	1,259,149	30,490,190
2020	17	0.2703		1,190,002	440,530	1,630,532	5,944,304	4,313,772		321,621	119,062	440,682	1,606,561	1,165,879	31,656,069

TABLE A-32 (continued)
Sixth Water Power Plant Economic Analysis
Q = 500 cfs, Installed Capacity = 41,598 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2021	18	0.2502		1,190,002	440,530	1,630,532	5,944,304	4,313,772		297,797	110,242	408,039	1,487,556	1,079,517	32,735,586
2022	19	0.2317		1,190,002	440,530	1,630,532	5,944,304	4,313,772		275,738	102,076	377,814	1,377,367	999,553	33,735,139
2023	20	0.2145		1,190,002	440,530	1,630,532	5,944,304	4,313,772		255,313	94,515	349,828	1,275,340	925,512	34,660,651
2024	21	0.1987		1,190,002	440,530	1,630,532	5,944,304	4,313,772		236,401	87,514	323,915	1,180,870	856,956	35,517,607
2025	22	0.1839		1,190,002	440,530	1,630,532	5,944,304	4,313,772		218,890	81,031	299,921	1,093,398	793,477	36,311,084
2026	23	0.1703		1,190,002	440,530	1,630,532	5,944,304	4,313,772		202,676	75,029	277,704	1,012,406	734,701	37,045,785
2027	24	0.1577		1,190,002	440,530	1,630,532	5,944,304	4,313,772		187,663	69,471	257,134	937,413	680,279	37,726,064
2028	25	0.1460		1,190,002	440,530	1,630,532	5,944,304	4,313,772		173,762	64,325	238,087	867,975	629,888	38,355,952
2029	26	0.1352		1,190,002	440,530	1,630,532	5,944,304	4,313,772		160,890	59,560	220,451	803,680	583,230	38,939,182
2030	27	0.1252		1,190,002	440,530	1,630,532	5,944,304	4,313,772		148,973	55,149	204,121	744,148	540,027	39,479,209
2031	28	0.1159		1,190,002	440,530	1,630,532	5,944,304	4,313,772		137,938	51,063	189,001	689,026	500,025	39,979,235
2032	29	0.1073		1,190,002	440,530	1,630,532	5,944,304	4,313,772		127,720	47,281	175,001	637,987	462,986	40,442,221
2033	30	0.0994		1,190,002	440,530	1,630,532	5,944,304	4,313,772		118,259	43,779	162,038	590,729	428,691	40,870,912
2034	31	0.0920		1,190,002	440,530	1,630,532	5,944,304	4,313,772		109,499	40,536	150,035	546,971	396,936	41,267,848
2035	32	0.0852		1,190,002	440,530	1,630,532	5,944,304	4,313,772		101,388	37,533	138,921	506,455	367,534	41,635,382
2036	33	0.0789		1,190,002	440,530	1,630,532	5,944,304	4,313,772		93,878	34,753	128,631	468,940	340,309	41,975,691
2037	34	0.0730		1,190,002	440,530	1,630,532	5,944,304	4,313,772		86,924	32,179	119,103	434,203	315,101	42,290,792
2038	35	0.0676		1,190,002	440,530	1,630,532	5,944,304	4,313,772		80,485	29,795	110,280	402,040	291,760	42,582,552
2039	36	0.0626		1,190,002	440,530	1,630,532	5,944,304	4,313,772		74,523	27,588	102,111	372,260	270,148	42,852,700
2040	37	0.0580		1,190,002	440,530	1,630,532	5,944,304	4,313,772		69,003	25,544	94,548	344,685	250,137	43,102,837
2041	38	0.0537		1,190,002	440,530	1,630,532	5,944,304	4,313,772		63,892	23,652	87,544	319,153	231,608	43,334,445
2042	39	0.0497		1,190,002	440,530	1,630,532	5,944,304	4,313,772		59,159	21,900	81,059	295,512	214,452	43,548,898
2043	40	0.0460		1,190,002	440,530	1,630,532	5,944,304	4,313,772		54,777	20,278	75,055	273,622	198,567	43,747,465
2044	41	0.0426		1,190,002	440,530	1,630,532	5,944,304	4,313,772		50,719	18,776	69,495	253,354	183,858	43,931,323
2045	42	0.0395		1,190,002	440,530	1,630,532	5,944,304	4,313,772		46,962	17,385	64,347	234,587	170,239	44,101,562
2046	43	0.0365		1,190,002	440,530	1,630,532	5,944,304	4,313,772		43,484	16,097	59,581	217,210	157,629	44,259,191

TABLE A-32 (continued)
Sixth Water Power Plant Economic Analysis
Q = 500 cfs, Installed Capacity = 41,598 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2047	44	0.0338		1,190,002	440,530	1,630,532	5,944,304	4,313,772		40,263	14,905	55,168	201,120	145,953	44,405,144
2048	45	0.0313		1,190,002	440,530	1,630,532	5,944,304	4,313,772		37,280	13,801	51,081	186,222	135,141	44,540,285
2049	46	0.0290		1,190,002	440,530	1,630,532	5,944,304	4,313,772		34,519	12,779	47,297	172,428	125,131	44,665,416
2050	47	0.0269		1,190,002	440,530	1,630,532	5,944,304	4,313,772		31,962	11,832	43,794	159,656	115,862	44,781,278
2051	48	0.0249		1,190,002	440,530	1,630,532	5,944,304	4,313,772		29,594	10,956	40,550	147,829	107,280	44,888,557
2052	49	0.0230		1,190,002	440,530	1,630,532	5,944,304	4,313,772		27,402	10,144	37,546	136,879	99,333	44,987,890
2053	50	0.0213		1,190,002	440,530	1,630,532	5,944,304	4,313,772		25,372	9,393	34,765	126,740	91,975	45,079,865
2054	51	0.0197		1,190,002	440,530	1,630,532	5,944,304	4,313,772		23,493	8,697	32,190	117,352	85,162	45,165,027
2055	52	0.0183		1,190,002	440,530	1,630,532	5,944,304	4,313,772		21,753	8,053	29,805	108,659	78,854	45,243,881
								Total	**0**	**12,481,029**	**4,620,382**	**17,101,411**	**62,345,292**		

Note: Assumptions
Construction period – 2 years
Interest rate during construction (for IDC estimate) – 5.875%

TABLE A-33
Sixth Water Power Plant Economic Analysis
Q = 600 cfs, Installed Capacity = 47,904 kW

Rated Flow	600 cu ft/s
Rated Net Head	1,087 ft
Rated Installed Capacity	47,904 kW
Synchronous Speed	300 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$28,578,637 (USD)
Total Project Cost	$32,489,694 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	3.27
NPV	42,865,573
US$/KW	678
US$/kWh	0.222

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	3	0.7938		1,316,465	487,345	1,803,811	5,890,823	4,087,013		1,045,052	386,870	1,431,923	4,676,325	3,244,402	3,244,402
2007	4	0.7350		1,316,465	487,345	1,803,811	5,890,823	4,087,013		967,641	358,213	1,325,855	4,329,931	3,004,076	6,248,479
2008	5	0.6806		1,316,465	487,345	1,803,811	5,890,823	4,087,013		895,964	331,679	1,227,643	4,009,195	2,781,552	9,030,031
2009	6	0.6302		1,316,465	487,345	1,803,811	5,890,823	4,087,013		829,596	307,110	1,136,707	3,712,218	2,575,511	11,605,542
2010	7	0.5835		1,316,465	487,345	1,803,811	5,890,823	4,087,013		768,145	284,361	1,052,506	3,437,239	2,384,733	13,990,274
2011	8	0.5403		1,316,465	487,345	1,803,811	5,890,823	4,087,013		711,245	263,298	974,543	3,182,628	2,208,086	16,198,360
2012	9	0.5002		1,316,465	487,345	1,803,811	5,890,823	4,087,013		658,560	243,794	902,354	2,946,878	2,044,524	18,242,884
2013	10	0.4632		1,316,465	487,345	1,803,811	5,890,823	4,087,013		609,778	225,735	835,513	2,728,591	1,893,078	20,135,961
2014	11	0.4289		1,316,465	487,345	1,803,811	5,890,823	4,087,013		564,609	209,014	773,623	2,526,473	1,752,850	21,888,811
2015	12	0.3971		1,316,465	487,345	1,803,811	5,890,823	4,087,013		522,786	193,532	716,318	2,339,327	1,623,009	23,511,820
2016	13	0.3677		1,316,465	487,345	1,803,811	5,890,823	4,087,013		484,061	179,196	663,257	2,166,043	1,502,786	25,014,606
2017	14	0.3405		1,316,465	487,345	1,803,811	5,890,823	4,087,013		448,205	165,922	614,127	2,005,596	1,391,469	26,406,074
2018	15	0.3152		1,316,465	487,345	1,803,811	5,890,823	4,087,013		415,005	153,632	568,636	1,857,033	1,288,397	27,694,471
2019	16	0.2919		1,316,465	487,345	1,803,811	5,890,823	4,087,013		384,264	142,251	526,515	1,719,475	1,192,960	28,887,431
2020	17	0.2703		1,316,465	487,345	1,803,811	5,890,823	4,087,013		355,800	131,714	487,514	1,592,107	1,104,593	29,992,024

TABLE A-33 (continued)
Sixth Water Power Plant Economic Analysis
Q = 600 cfs, Installed Capacity = 47,904 kW

			Costs						Present Value							
									Costs							
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2021	18	0.2502		1,316,465	487,345	1,803,811	5,890,823	4,087,013		329,444	121,958	451,402	1,474,173	1,022,771	31,014,795
2022	19	0.2317		1,316,465	487,345	1,803,811	5,890,823	4,087,013		305,041	112,924	417,965	1,364,975	947,010	31,961,805
2023	20	0.2145		1,316,465	487,345	1,803,811	5,890,823	4,087,013		282,445	104,559	387,004	1,263,866	876,861	32,838,666
2024	21	0.1987		1,316,465	487,345	1,803,811	5,890,823	4,087,013		261,523	96,814	358,337	1,170,246	811,909	33,650,574
2025	22	0.1839		1,316,465	487,345	1,803,811	5,890,823	4,087,013		242,151	89,643	331,794	1,083,561	751,767	34,402,342
2026	23	0.1703		1,316,465	487,345	1,803,811	5,890,823	4,087,013		224,214	83,002	307,216	1,003,297	696,081	35,098,422
2027	24	0.1577		1,316,465	487,345	1,803,811	5,890,823	4,087,013		207,606	76,854	284,460	928,979	644,519	35,742,942
2028	25	0.1460		1,316,465	487,345	1,803,811	5,890,823	4,087,013		192,227	71,161	263,389	860,166	596,777	36,339,719
2029	26	0.1352		1,316,465	487,345	1,803,811	5,890,823	4,087,013		177,988	65,890	243,878	796,450	552,571	36,892,290
2030	27	0.1252		1,316,465	487,345	1,803,811	5,890,823	4,087,013		164,804	61,009	225,813	737,453	511,640	37,403,930
2031	28	0.1159		1,316,465	487,345	1,803,811	5,890,823	4,087,013		152,596	56,490	209,086	682,827	473,741	37,877,671
2032	29	0.1073		1,316,465	487,345	1,803,811	5,890,823	4,087,013		141,293	52,306	193,599	632,247	438,649	38,316,320
2033	30	0.0994		1,316,465	487,345	1,803,811	5,890,823	4,087,013		130,827	48,431	179,258	585,414	406,156	38,722,476
2034	31	0.0920		1,316,465	487,345	1,803,811	5,890,823	4,087,013		121,136	44,844	165,980	542,050	376,071	39,098,547
2035	32	0.0852		1,316,465	487,345	1,803,811	5,890,823	4,087,013		112,163	41,522	153,685	501,898	348,214	39,446,760
2036	33	0.0789		1,316,465	487,345	1,803,811	5,890,823	4,087,013		103,855	38,446	142,301	464,721	322,420	39,769,180
2037	34	0.0730		1,316,465	487,345	1,803,811	5,890,823	4,087,013		96,162	35,598	131,760	430,297	298,537	40,067,718
2038	35	0.0676		1,316,465	487,345	1,803,811	5,890,823	4,087,013		89,039	32,961	122,000	398,423	276,423	40,344,141
2039	36	0.0626		1,316,465	487,345	1,803,811	5,890,823	4,087,013		82,443	30,520	112,963	368,910	255,947	40,600,088
2040	37	0.0580		1,316,465	487,345	1,803,811	5,890,823	4,087,013		76,336	28,259	104,595	341,584	236,988	40,837,077
2041	38	0.0537		1,316,465	487,345	1,803,811	5,890,823	4,087,013		70,682	26,166	96,847	316,281	219,434	41,056,510
2042	39	0.0497		1,316,465	487,345	1,803,811	5,890,823	4,087,013		65,446	24,228	89,674	292,853	203,179	41,259,690
2043	40	0.0460		1,316,465	487,345	1,803,811	5,890,823	4,087,013		60,598	22,433	83,031	271,160	188,129	41,447,819
2044	41	0.0426		1,316,465	487,345	1,803,811	5,890,823	4,087,013		56,109	20,771	76,881	251,074	174,194	41,622,012
2045	42	0.0395		1,316,465	487,345	1,803,811	5,890,823	4,087,013		51,953	19,233	71,186	232,476	161,290	41,783,302
2046	43	0.0365		1,316,465	487,345	1,803,811	5,890,823	4,087,013		48,105	17,808	65,913	215,256	149,343	41,932,645

TABLE A-33 (continued)
Sixth Water Power Plant Economic Analysis
Q = 600 cfs, Installed Capacity = 47,904 kW

									Present Value						
			Costs						Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2047	44	0.0338		1,316,465	487,345	1,803,811	5,890,823	4,087,013		44,541	16,489	61,030	199,311	138,280	42,070,926
2048	45	0.0313		1,316,465	487,345	1,803,811	5,890,823	4,087,013		41,242	15,267	56,510	184,547	128,037	42,198,963
2049	46	0.0290		1,316,465	487,345	1,803,811	5,890,823	4,087,013		38,187	14,137	52,324	170,877	118,553	42,317,516
2050	47	0.0269		1,316,465	487,345	1,803,811	5,890,823	4,087,013		35,358	13,089	48,448	158,219	109,771	42,427,288
2051	48	0.0249		1,316,465	487,345	1,803,811	5,890,823	4,087,013		32,739	12,120	44,859	146,499	101,640	42,528,928
2052	49	0.0230		1,316,465	487,345	1,803,811	5,890,823	4,087,013		30,314	11,222	41,536	135,648	94,111	42,623,039
2053	50	0.0213		1,316,465	487,345	1,803,811	5,890,823	4,087,013		28,069	10,391	38,459	125,600	87,140	42,710,179
2054	51	0.0197		1,316,465	487,345	1,803,811	5,890,823	4,087,013		25,989	9,621	35,611	116,296	80,685	42,790,865
2055	52	0.0183		1,316,465	487,345	1,803,811	5,890,823	4,087,013		24,064	8,908	32,973	107,681	74,709	42,865,573
								Total	**0**	**13,807,404**	**5,111,396**	**18,918,800**	**61,784,373**		

Note: Assumptions
Construction period – 2 years
Interest rate during construction (for IDC estimate) – 5.875%

TABLE A-34
Upper Diamond Fork Power Plant Economic Analysis
Q = 80 cfs, Installed Capacity = 3,175 kW

Rated Flow	80 cu ft/s
Rated Net Head	541 ft
Rated Installed Capacity	3,175 kW
Synchronous Speed	327 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$3,818,065 (USD)
Total Project Cost	$4,340,576 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	4.18
NPV	8,042,944
US$/KW	1,367
US$/kWh	0.194

									Present Value						
			Costs						Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	3	0.7938		175,878	65,109	240,986	1,007,840	766,853		139,618	51,685	191,303	800,056	608,753	608,753
2007	4	0.7350		175,878	65,109	240,986	1,007,840	766,853		129,275	47,857	177,132	740,792	563,660	1,172,413
2008	5	0.6806		175,878	65,109	240,986	1,007,840	766,853		119,700	44,312	164,011	685,919	521,908	1,694,321
2009	6	0.6302		175,878	65,109	240,986	1,007,840	766,853		110,833	41,029	151,862	635,110	483,248	2,177,569
2010	7	0.5835		175,878	65,109	240,986	1,007,840	766,853		102,623	37,990	140,613	588,065	447,452	2,625,020
2011	8	0.5403		175,878	65,109	240,986	1,007,840	766,853		95,021	35,176	130,197	544,505	414,307	3,039,327
2012	9	0.5002		175,878	65,109	240,986	1,007,840	766,853		87,983	32,571	120,553	504,171	383,618	3,422,945
2013	10	0.4632		175,878	65,109	240,986	1,007,840	766,853		81,465	30,158	111,623	466,825	355,202	3,778,146
2014	11	0.4289		175,878	65,109	240,986	1,007,840	766,853		75,431	27,924	103,355	432,245	328,890	4,107,037
2015	12	0.3971		175,878	65,109	240,986	1,007,840	766,853		69,844	25,856	95,699	400,227	304,528	4,411,565
2016	13	0.3677		175,878	65,109	240,986	1,007,840	766,853		64,670	23,940	88,610	370,581	281,970	4,693,535
2017	14	0.3405		175,878	65,109	240,986	1,007,840	766,853		59,880	22,167	82,047	343,130	261,084	4,954,619
2018	15	0.3152		175,878	65,109	240,986	1,007,840	766,853		55,444	20,525	75,969	317,713	241,744	5,196,363
2019	16	0.2919		175,878	65,109	240,986	1,007,840	766,853		51,337	19,005	70,342	294,179	223,837	5,420,200
2020	17	0.2703		175,878	65,109	240,986	1,007,840	766,853		47,534	17,597	65,131	272,388	207,257	5,627,457

TABLE A-34 (continued)
Upper Diamond Fork Power Plant Economic Analysis
Q = 80 cfs, Installed Capacity = 3,175 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2021	18	0.2502		175,878	65,109	240,986	1,007,840	766,853		44,013	16,293	60,307	252,211	191,904	5,819,361
2022	19	0.2317		175,878	65,109	240,986	1,007,840	766,853		40,753	15,086	55,839	233,529	177,689	5,997,051
2023	20	0.2145		175,878	65,109	240,986	1,007,840	766,853		37,734	13,969	51,703	216,230	164,527	6,161,578
2024	21	0.1987		175,878	65,109	240,986	1,007,840	766,853		34,939	12,934	47,873	200,213	152,340	6,313,918
2025	22	0.1839		175,878	65,109	240,986	1,007,840	766,853		32,351	11,976	44,327	185,383	141,055	6,454,973
2026	23	0.1703		175,878	65,109	240,986	1,007,840	766,853		29,955	11,089	41,044	171,651	130,607	6,585,580
2027	24	0.1577		175,878	65,109	240,986	1,007,840	766,853		27,736	10,268	38,003	158,936	120,932	6,706,512
2028	25	0.1460		175,878	65,109	240,986	1,007,840	766,853		25,681	9,507	35,188	147,163	111,974	6,818,486
2029	26	0.1352		175,878	65,109	240,986	1,007,840	766,853		23,779	8,803	32,582	136,262	103,680	6,922,166
2030	27	0.1252		175,878	65,109	240,986	1,007,840	766,853		22,018	8,151	30,168	126,168	96,000	7,018,166
2031	28	0.1159		175,878	65,109	240,986	1,007,840	766,853		20,387	7,547	27,934	116,822	88,889	7,107,055
2032	29	0.1073		175,878	65,109	240,986	1,007,840	766,853		18,877	6,988	25,864	108,169	82,304	7,189,360
2033	30	0.0994		175,878	65,109	240,986	1,007,840	766,853		17,478	6,470	23,949	100,156	76,208	7,265,567
2034	31	0.0920		175,878	65,109	240,986	1,007,840	766,853		16,184	5,991	22,175	92,737	70,563	7,336,130
2035	32	0.0852		175,878	65,109	240,986	1,007,840	766,853		14,985	5,547	20,532	85,868	65,336	7,401,466
2036	33	0.0789		175,878	65,109	240,986	1,007,840	766,853		13,875	5,136	19,011	79,507	60,496	7,461,962
2037	34	0.0730		175,878	65,109	240,986	1,007,840	766,853		12,847	4,756	17,603	73,618	56,015	7,517,978
2038	35	0.0676		175,878	65,109	240,986	1,007,840	766,853		11,895	4,404	16,299	68,165	51,866	7,569,843
2039	36	0.0626		175,878	65,109	240,986	1,007,840	766,853		11,014	4,077	15,092	63,116	48,024	7,617,867
2040	37	0.0580		175,878	65,109	240,986	1,007,840	766,853		10,198	3,775	13,974	58,440	44,467	7,662,334
2041	38	0.0537		175,878	65,109	240,986	1,007,840	766,853		9,443	3,496	12,939	54,111	41,173	7,703,506
2042	39	0.0497		175,878	65,109	240,986	1,007,840	766,853		8,743	3,237	11,980	50,103	38,123	7,741,629
2043	40	0.0460		175,878	65,109	240,986	1,007,840	766,853		8,096	2,997	11,093	46,392	35,299	7,776,928
2044	41	0.0426		175,878	65,109	240,986	1,007,840	766,853		7,496	2,775	10,271	42,955	32,684	7,809,613
2045	42	0.0395		175,878	65,109	240,986	1,007,840	766,853		6,941	2,569	9,510	39,774	30,263	7,839,876

TABLE A-34 (continued)
Upper Diamond Fork Power Plant Economic Analysis
Q = 80 cfs, Installed Capacity = 3,175 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2046	43	0.0365		175,878	65,109	240,986	1,007,840	766,853		6,427	2,379	8,806	36,827	28,021	7,867,897
2047	44	0.0338		175,878	65,109	240,986	1,007,840	766,853		5,951	2,203	8,154	34,099	25,946	7,893,843
2048	45	0.0313		175,878	65,109	240,986	1,007,840	766,853		5,510	2,040	7,550	31,573	24,024	7,917,867
2049	46	0.0290		175,878	65,109	240,986	1,007,840	766,853		5,102	1,889	6,990	29,235	22,244	7,940,111
2050	47	0.0269		175,878	65,109	240,986	1,007,840	766,853		4,724	1,749	6,473	27,069	20,597	7,960,708
2051	48	0.0249		175,878	65,109	240,986	1,007,840	766,853		4,374	1,619	5,993	25,064	19,071	7,979,779
2052	49	0.0230		175,878	65,109	240,986	1,007,840	766,853		4,050	1,499	5,549	23,207	17,658	7,997,437
2053	50	0.0213		175,878	65,109	240,986	1,007,840	766,853		3,750	1,388	5,138	21,488	16,350	8,013,787
2054	51	0.0197		175,878	65,109	240,986	1,007,840	766,853		3,472	1,285	4,758	19,897	15,139	8,028,927
2055	52	0.0183		175,878	65,109	240,986	1,007,840	766,853		3,215	1,190	4,405	18,423	14,018	8,042,944
								Total	**0**	**1,844,649**	**682,875**	**2,527,524**	**10,570,469**		

Note: Assumptions
Construction period – 2 years
Interest rate during construction (for IDC estimate) – 5.875%

TABLE A-35
Upper Diamond Fork Power Plant Economic Analysis
Q = 100 cfs, Installed Capacity = 3,995 kW

Rated Flow	100 cu ft/s
Rated Net Head	541 ft
Rated Installed Capacity	3,995 kW
Synchronous Speed	300 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$4,498,053 (USD)
Total Project Cost	$5,113,623 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	4.15
NPV	9,382,082
US$/KW	1,280
US$/kWh	0.195

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	3	0.7938		207,201	76,704	283,906	1,178,439	894,533		164,483	60,890	225,373	935,483	710,109	710,109
2007	4	0.7350		207,201	76,704	283,906	1,178,439	894,533		152,299	56,380	208,679	866,188	657,509	1,367,618
2008	5	0.6806		207,201	76,704	283,906	1,178,439	894,533		141,018	52,204	193,221	802,026	608,804	1,976,422
2009	6	0.6302		207,201	76,704	283,906	1,178,439	894,533		130,572	48,337	178,909	742,616	563,708	2,540,130
2010	7	0.5835		207,201	76,704	283,906	1,178,439	894,533		120,900	44,756	165,656	687,608	521,952	3,062,082
2011	8	0.5403		207,201	76,704	283,906	1,178,439	894,533		111,944	41,441	153,385	636,674	483,289	3,545,370
2012	9	0.5002		207,201	76,704	283,906	1,178,439	894,533		103,652	38,371	142,024	589,513	447,489	3,992,860
2013	10	0.4632		207,201	76,704	283,906	1,178,439	894,533		95,974	35,529	131,503	545,845	414,342	4,407,202
2014	11	0.4289		207,201	76,704	283,906	1,178,439	894,533		88,865	32,897	121,762	505,412	383,650	4,790,852
2015	12	0.3971		207,201	76,704	283,906	1,178,439	894,533		82,282	30,460	112,743	467,974	355,231	5,146,083
2016	13	0.3677		207,201	76,704	283,906	1,178,439	894,533		76,187	28,204	104,392	433,310	328,918	5,475,001
2017	14	0.3405		207,201	76,704	283,906	1,178,439	894,533		70,544	26,115	96,659	401,213	304,554	5,779,555
2018	15	0.3152		207,201	76,704	283,906	1,178,439	894,533		65,318	24,180	89,499	371,493	281,994	6,061,549
2019	16	0.2919		207,201	76,704	283,906	1,178,439	894,533		60,480	22,389	82,869	343,975	261,106	6,322,655
2020	17	0.2703		207,201	76,704	283,906	1,178,439	894,533		56,000	20,731	76,731	318,495	241,765	6,564,420

TABLE A-35 (continued)
Upper Diamond Fork Power Plant Economic Analysis
Q = 100 cfs, Installed Capacity = 3,995 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2021	18	0.2502		207,201	76,704	283,906	1,178,439	894,533		51,852	19,195	71,047	294,903	223,856	6,788,276
2022	19	0.2317		207,201	76,704	283,906	1,178,439	894,533		48,011	17,773	65,784	273,059	207,274	6,995,550
2023	20	0.2145		207,201	76,704	283,906	1,178,439	894,533		44,455	16,457	60,911	252,832	191,921	7,187,470
2024	21	0.1987		207,201	76,704	283,906	1,178,439	894,533		41,162	15,238	56,399	234,104	177,704	7,365,175
2025	22	0.1839		207,201	76,704	283,906	1,178,439	894,533		38,113	14,109	52,222	216,763	164,541	7,529,716
2026	23	0.1703		207,201	76,704	283,906	1,178,439	894,533		35,290	13,064	48,353	200,706	152,353	7,682,068
2027	24	0.1577		207,201	76,704	283,906	1,178,439	894,533		32,676	12,096	44,772	185,839	141,067	7,823,136
2028	25	0.1460		207,201	76,704	283,906	1,178,439	894,533		30,255	11,200	41,455	172,073	130,618	7,953,753
2029	26	0.1352		207,201	76,704	283,906	1,178,439	894,533		28,014	10,371	38,385	159,327	120,942	8,074,696
2030	27	0.1252		207,201	76,704	283,906	1,178,439	894,533		25,939	9,602	35,541	147,525	111,984	8,186,680
2031	28	0.1159		207,201	76,704	283,906	1,178,439	894,533		24,017	8,891	32,909	136,597	103,689	8,290,368
2032	29	0.1073		207,201	76,704	283,906	1,178,439	894,533		22,238	8,232	30,471	126,479	96,008	8,386,376
2033	30	0.0994		207,201	76,704	283,906	1,178,439	894,533		20,591	7,623	28,214	117,110	88,896	8,475,273
2034	31	0.0920		207,201	76,704	283,906	1,178,439	894,533		19,066	7,058	26,124	108,435	82,311	8,557,584
2035	32	0.0852		207,201	76,704	283,906	1,178,439	894,533		17,654	6,535	24,189	100,403	76,214	8,633,798
2036	33	0.0789		207,201	76,704	283,906	1,178,439	894,533		16,346	6,051	22,397	92,966	70,569	8,704,367
2037	34	0.0730		207,201	76,704	283,906	1,178,439	894,533		15,135	5,603	20,738	86,079	65,341	8,769,709
2038	35	0.0676		207,201	76,704	283,906	1,178,439	894,533		14,014	5,188	19,202	79,703	60,501	8,830,210
2039	36	0.0626		207,201	76,704	283,906	1,178,439	894,533		12,976	4,804	17,779	73,799	56,020	8,886,230
2040	37	0.0580		207,201	76,704	283,906	1,178,439	894,533		12,015	4,448	16,462	68,333	51,870	8,938,100
2041	38	0.0537		207,201	76,704	283,906	1,178,439	894,533		11,125	4,118	15,243	63,271	48,028	8,986,128
2042	39	0.0497		207,201	76,704	283,906	1,178,439	894,533		10,301	3,813	14,114	58,584	44,470	9,030,598
2043	40	0.0460		207,201	76,704	283,906	1,178,439	894,533		9,538	3,531	13,068	54,245	41,176	9,071,774
2044	41	0.0426		207,201	76,704	283,906	1,178,439	894,533		8,831	3,269	12,100	50,227	38,126	9,109,901
2045	42	0.0395		207,201	76,704	283,906	1,178,439	894,533		8,177	3,027	11,204	46,506	35,302	9,145,203
2046	43	0.0365		207,201	76,704	283,906	1,178,439	894,533		7,571	2,803	10,374	43,061	32,687	9,177,890

TABLE A-35 (continued)
Upper Diamond Fork Power Plant Economic Analysis
Q = 100 cfs, Installed Capacity = 3,995 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2047	44	0.0338		207,201	76,704	283,906	1,178,439	894,533		7,010	2,595	9,606	39,871	30,266	9,208,155
2048	45	0.0313		207,201	76,704	283,906	1,178,439	894,533		6,491	2,403	8,894	36,918	28,024	9,236,179
2049	46	0.0290		207,201	76,704	283,906	1,178,439	894,533		6,010	2,225	8,235	34,183	25,948	9,262,127
2050	47	0.0269		207,201	76,704	283,906	1,178,439	894,533		5,565	2,060	7,625	31,651	24,026	9,286,153
2051	48	0.0249		207,201	76,704	283,906	1,178,439	894,533		5,153	1,908	7,060	29,307	22,246	9,308,399
2052	49	0.0230		207,201	76,704	283,906	1,178,439	894,533		4,771	1,766	6,537	27,136	20,598	9,328,998
2053	50	0.0213		207,201	76,704	283,906	1,178,439	894,533		4,418	1,635	6,053	25,126	19,073	9,348,070
2054	51	0.0197		207,201	76,704	283,906	1,178,439	894,533		4,091	1,514	5,605	23,265	17,660	9,365,730
2055	52	0.0183		207,201	76,704	283,906	1,178,439	894,533		3,788	1,402	5,190	21,541	16,352	9,382,082
								Total	0	2,173,177	804,494	2,977,671	12,359,752		

Note: Assumptions
Construction period – 2 years
Interest rate during construction (for IDC estimate) – 5.875%

TABLE A-36
Upper Diamond Fork Power Plant Economic Analysis
Q = 125 cfs, Installed Capacity = 5,000 kW

Rated Flow	125 cu ft/s
Rated Net Head	540.4 ft
Rated Installed Capacity	5,000 kW
Synchronous Speed	276.9 rpm
Energy Tarif	4.5 cents/kWh
O&M Cost (% of Total Project)	1,50%
Construction Cost + IDC	$5,271,999 (USD)
Total Project Cost	$5,993,485 (USD)
Interest Rate for Debt Service	3.22%
Amortization Period	50 years
Discount Rate	8%

B/C	4.09
NPV	10,783,340
US$/KW	1,199
US$/kWh	0.198

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2004	1	0.9259	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	2	0.8573	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	3	0.7938		242,853	89,902	332,755	1,360,891	1,028,136		192,784	71,367	264,152	1,080,319	816,168	816,168
2007	4	0.7350		242,853	89,902	332,755	1,360,891	1,028,136		178,504	66,081	244,585	1,000,296	755,711	1,571,878
2008	5	0.6806		242,853	89,902	332,755	1,360,891	1,028,136		165,282	61,186	226,468	926,200	699,732	2,271,611
2009	6	0.6302		242,853	89,902	332,755	1,360,891	1,028,136		153,038	56,654	209,692	857,592	647,900	2,919,511
2010	7	0.5835		242,853	89,902	332,755	1,360,891	1,028,136		141,702	52,457	194,159	794,067	599,908	3,519,418
2011	8	0.5403		242,853	89,902	332,755	1,360,891	1,028,136		131,206	48,571	179,777	735,247	555,470	4,074,888
2012	9	0.5002		242,853	89,902	332,755	1,360,891	1,028,136		121,487	44,974	166,460	680,784	514,324	4,589,212
2013	10	0.4632		242,853	89,902	332,755	1,360,891	1,028,136		112,488	41,642	154,130	630,356	476,226	5,065,438
2014	11	0.4289		242,853	89,902	332,755	1,360,891	1,028,136		104,155	38,558	142,713	583,663	440,950	5,506,388
2015	12	0.3971		242,853	89,902	332,755	1,360,891	1,028,136		96,440	35,701	132,142	540,429	408,287	5,914,675
2016	13	0.3677		242,853	89,902	332,755	1,360,891	1,028,136		89,296	33,057	122,353	500,397	378,044	6,292,719
2017	14	0.3405		242,853	89,902	332,755	1,360,891	1,028,136		82,682	30,608	113,290	463,330	350,040	6,642,759
2018	15	0.3152		242,853	89,902	332,755	1,360,891	1,028,136		76,557	28,341	104,898	429,010	324,111	6,966,870
2019	16	0.2919		242,853	89,902	332,755	1,360,891	1,028,136		70,886	26,242	97,128	397,231	300,103	7,266,974
2020	17	0.2703		242,853	89,902	332,755	1,360,891	1,028,136		65,636	24,298	89,933	367,807	277,873	7,544,847

TABLE A-36 (continued)
Upper Diamond Fork Power Plant Economic Analysis
Q = 125 cfs, Installed Capacity = 5,000 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2021	18	0.2502		242,853	89,902	332,755	1,360,891	1,028,136		60,774	22,498	83,272	340,562	257,290	7,802,137
2022	19	0.2317		242,853	89,902	332,755	1,360,891	1,028,136		56,272	20,831	77,103	315,335	238,232	8,040,368
2023	20	0.2145		242,853	89,902	332,755	1,360,891	1,028,136		52,104	19,288	71,392	291,977	220,585	8,260,953
2024	21	0.1987		242,853	89,902	332,755	1,360,891	1,028,136		48,244	17,860	66,104	270,349	204,245	8,465,198
2025	22	0.1839		242,853	89,902	332,755	1,360,891	1,028,136		44,670	16,537	61,207	250,323	189,116	8,654,314
2026	23	0.1703		242,853	89,902	332,755	1,360,891	1,028,136		41,362	15,312	56,673	231,781	175,107	8,829,422
2027	24	0.1577		242,853	89,902	332,755	1,360,891	1,028,136		38,298	14,178	52,475	214,612	162,136	8,991,558
2028	25	0.1460		242,853	89,902	332,755	1,360,891	1,028,136		35,461	13,127	48,588	198,714	150,126	9,141,684
2029	26	0.1352		242,853	89,902	332,755	1,360,891	1,028,136		32,834	12,155	44,989	183,995	139,006	9,280,690
2030	27	0.1252		242,853	89,902	332,755	1,360,891	1,028,136		30,402	11,255	41,657	170,366	128,709	9,409,399
2031	28	0.1159		242,853	89,902	332,755	1,360,891	1,028,136		28,150	10,421	38,571	157,746	119,175	9,528,574
2032	29	0.1073		242,853	89,902	332,755	1,360,891	1,028,136		26,065	9,649	35,714	146,061	110,347	9,638,921
2033	30	0.0994		242,853	89,902	332,755	1,360,891	1,028,136		24,134	8,934	33,068	135,242	102,173	9,741,095
2034	31	0.0920		242,853	89,902	332,755	1,360,891	1,028,136		22,346	8,272	30,619	125,224	94,605	9,835,700
2035	32	0.0852		242,853	89,902	332,755	1,360,891	1,028,136		20,691	7,660	28,351	115,948	87,597	9,923,297
2036	33	0.0789		242,853	89,902	332,755	1,360,891	1,028,136		19,158	7,092	26,251	107,359	81,109	10,004,406
2037	34	0.0730		242,853	89,902	332,755	1,360,891	1,028,136		17,739	6,567	24,306	99,407	75,101	10,079,506
2038	35	0.0676		242,853	89,902	332,755	1,360,891	1,028,136		16,425	6,080	22,506	92,043	69,538	10,149,044
2039	36	0.0626		242,853	89,902	332,755	1,360,891	1,028,136		15,209	5,630	20,839	85,225	64,387	10,213,430
2040	37	0.0580		242,853	89,902	332,755	1,360,891	1,028,136		14,082	5,213	19,295	78,912	59,617	10,273,048
2041	38	0.0537		242,853	89,902	332,755	1,360,891	1,028,136		13,039	4,827	17,866	73,067	55,201	10,328,249
2042	39	0.0497		242,853	89,902	332,755	1,360,891	1,028,136		12,073	4,469	16,542	67,655	51,112	10,379,361
2043	40	0.0460		242,853	89,902	332,755	1,360,891	1,028,136		11,179	4,138	15,317	62,643	47,326	10,426,687
2044	41	0.0426		242,853	89,902	332,755	1,360,891	1,028,136		10,351	3,832	14,182	58,003	43,820	10,470,507
2045	42	0.0395		242,853	89,902	332,755	1,360,891	1,028,136		9,584	3,548	13,132	53,706	40,574	10,511,082

TABLE A-36 (continued)
Upper Diamond Fork Power Plant Economic Analysis
Q = 125 cfs, Installed Capacity = 5,000 kW

			Costs						Present Value						
									Costs						
Year	Sequence No.	Discount Factor	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Net Benefits (US$)	Equity Disburs. (US$)	Debt Service (US$)	O&M (US$)	Total	Benefits (US$)	Cash Flow (US$)	Net Benefits (US$)
2046	43	0.0365		242,853	89,902	332,755	1,360,891	1,028,136		8,874	3,285	12,159	49,728	37,569	10,548,651
2047	44	0.0338		242,853	89,902	332,755	1,360,891	1,028,136		8,217	3,042	11,258	46,045	34,786	10,583,437
2048	45	0.0313		242,853	89,902	332,755	1,360,891	1,028,136		7,608	2,816	10,425	42,634	32,209	10,615,646
2049	46	0.0290		242,853	89,902	332,755	1,360,891	1,028,136		7,045	2,608	9,652	39,476	29,823	10,645,470
2050	47	0.0269		242,853	89,902	332,755	1,360,891	1,028,136		6,523	2,415	8,937	36,552	27,614	10,673,084
2051	48	0.0249		242,853	89,902	332,755	1,360,891	1,028,136		6,040	2,236	8,275	33,844	25,569	10,698,653
2052	49	0.0230		242,853	89,902	332,755	1,360,891	1,028,136		5,592	2,070	7,662	31,337	23,675	10,722,328
2053	50	0.0213		242,853	89,902	332,755	1,360,891	1,028,136		5,178	1,917	7,095	29,016	21,921	10,744,249
2054	51	0.0197		242,853	89,902	332,755	1,360,891	1,028,136		4,794	1,775	6,569	26,867	20,297	10,764,546
2055	52	0.0183		242,853	89,902	332,755	1,360,891	1,028,136		4,439	1,643	6,083	24,876	18,794	10,783,340
								Total	**0**	**2,547,099**	**942,917**	**3,490,016**	**14,273,355**		

Note: Assumptions

Construction period – 2 years

Interest rate during construction (for IDC estimate) – 5.875%

TABLE A-37
Actual Energy Benefits

Power Plant	Rated Flow (cfs)	Installed Capacity (kW)	Alternative	Net Energy (kWh)	Annual Energy Benefits (kWh)
Sixth Water	100	9,225	Proposed Action	59,874,993	2,694,375
	200	18,153		90,411,250	4,068,506
	300	26,706		112,702,555	5,071,615
	400	34,561		126,821,773	5,706,980
	500	41,598		132,095,638	5,944,304
	600	47,904		130,907,178	5,890,823
Upper Diamond Fork	80	3,175	Proposed Action	22,396,443	1,007,840
	100	3,995		26,187,533	1,178,439
	125	5,000		30,242,027	1,360,891

TABLE A-38
Sixth Water and Upper Diamond Power Plants Economic Indicators

Rated Flow (cfs)	Installed Capacity (kW)	NPV of Net Benefits	B/C Ratio	Cost per kW Installed ($/kW)	Cost per kWh of Net Energy ($/kWh)
Sixth Water Power Plant					
100	9,225	20,498,218	3.64	$1,445	$0.223
200	18,153	32,831,839	4.34	$931	$0.187
300	26,706	41,136,428	4.41	$775	$0.184
400	34,561	44,258,063	3.84	$775	$0.211
500	41,598	45,243,881	3.65	$706	$0.222
600	47,904	42,865,573	3.27	$678	$0.248
Upper Diamond Fork Power Plant					
80	3,175	8,042,944	4.18	$1,367	$0.194
100	3,995	9,382,082	4.15	$1,280	$0.195
125	5,000	10,783,340	4.09	$1,199	$0.198