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Impacts of Western Area Power Administration's Power Marketing Alternatives on Electric Utility Systems

Decision and Information Sciences Division

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Impacts of Western Area Power Administration's Power Marketing Alternatives on Electric Utility Systems

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Western Area Power Administration

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FOREWORD

This report is one of a series of technical memorandums prepared to support an environmental impact statement (EIS) on power marketing prepared by Argonne National Laboratory for the U.S. Department of Energy's Western Area Power Administration (Western). Western markets electricity produced at hydroelectric facilities operated by the Bureau of Reclamation. The facilities are known collectively as the Salt Lake City Area Integrated Projects (SLCA/IP) and include dams equipped for power generation on the Colorado, Green, Gunnison, and Rio Grande rivers and on Plateau Creek in the states of Arizona, Colorado, New Mexico, Utah, and Wyoming.

Western proposes to establish a level of commitment (sales) of long-term firm electrical capacity and energy from the SLCA/IP hydroelectric power plants; the impacts of this proposed action are evaluated in the EIS. Of the SLCA/IP facilities, only the Glen Canyon Dam, Flaming Gorge Dam, and Aspinall Unit (which includes Blue Mesa, Morrow Point, and Crystal dams) are influenced by Western's power scheduling and transmission decisions. For this reason, the impacts of hydropower operations at these three facilities were examined in the EIS.

The technical memorandums present detailed findings of studies conducted by Argonne National Laboratory specifically for the EIS. These studies are summarized in the EIS, and the results were used to assess environmental impacts related to alternative commitment levels. Technical memorandums were prepared on a number of socioeconomic and natural resource topics. Staff members of Argonne National Laboratory's Decision and Information Sciences Division and Environmental Assessment Division prepared these technical memorandums and the EIS as part of a joint effort managed by the Environmental Assessment Division.

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NOTATION

The following is a list of the acronyms, abbreviations, and initialisms (including units of measure) used in this document.

ACRONYMS, ABBREVIATIONS, AND INITIALISMS

AFBC	atmospheric fluidized-bed combustion
AGC	automatic generation control
ANL	Argonne National Laboratory
AOP	annual operating plan
APPA	Arizona Power Pooling Association
APS	Arizona Public Service Company
CROD	contract rate of delivery
CRSP	Colorado River Storage Project
CRSS	Colorado River Simulation System
DRI	Data Resources, Inc.
DSM	demand-side management
EIS	environmental impact statement
ELDC	equivalent load duration curve
ERM	expected reserve margin
FR	*Federal Register*
IGCC	integrated gasification combined cycle
IPP	Inland Power Pool
LAO	Loveland Area Office
LDC	load duration curve
LOLP	loss-of-load probability
LP	linear program
LTF	long-term firm
NPC	Nevada Power Company
NPV	net present value
O&M	operations and maintenance
PACE	Production and Capacity Expansion (model)
PEOG	PacifiCorp Electric Operations Group
PP&L	Pacific Power and Light Company
PSCO	Public Service Company of Colorado
PTC	pass-through cost

SLCA/IP	Salt Lake City Area Integrated Projects
SMN	Spot Market Network
SRP	Salt River Project
STF	short-term firm
TCC	total capital cost
TEP	Tucson Electric Power Company
TLAC	total levelized annual cost
UAMPS	Utah Associated Municipal Power Systems
UMPA	Utah Municipal Power Agency
WAUC	Western Area Upper Colorado
WMPA	Wyoming Municipal Power Agency
WSCC	Western Systems Coordinating Council

UNITS OF MEASURE

Btu	British thermal unit(s)
cfs	cubic feet per second
d	day
ft	foot (feet)
GWh	gigawatt-hour(s)
h	hour(s)
kV	kilovolt(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
mill	1/1000th of a dollar
MMBtu	million British thermal unit(s)
MW	megawatt(s)
MWh	megawatt-hour(s)

IMPACTS OF WESTERN AREA POWER ADMINISTRATION'S POWER MARKETING ALTERNATIVES ON ELECTRIC UTILITY SYSTEMS

by

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ABSTRACT

This technical memorandum estimates the effects of alternative contractual commitments that may be initiated by the Western Area Power Administration's Salt Lake City Area Office. It also studies hydropower operational restrictions at the Salt Lake City Area Integrated Projects in combination with these alternatives. Power marketing and hydropower operational effects are estimated in support of Western's Electric Power Marketing Environmental Impact Statement (EIS). Electricity production and capacity expansion for utility systems that will be directly affected by alternatives specified in the EIS are simulated. Cost estimates are presented by utility type and for various activities such as capacity expansion, generation, long-term firm purchases and sales, fixed operation and maintenance expenses, and spot market activities. Operational changes at hydropower facilities are also investigated.

1 INTRODUCTION

On December 20, 1988, the National Wildlife Federation and others filed suit against the Western Area Power Administration (Western) regarding the adequacy of Western's 1986 Environmental Assessment and FONSI (*National Wildlife Federation, et al. vs. Western Area Power Administration, et al.*, Docket No. 88C-1175-J, U.S. District Court, Central District of Utah). On September 29, 1989, the court entered an order allowing Western to implement the post-1989 contracts, provided that the aggregate commitment level of firm capacity and energy would remain essentially the same as the 1978 levels until Western had completed an environmental impact statement (EIS). The court was concerned that an increase in commitment, which was a principal feature of the post-1989 criteria, might result in changed operation of the Salt Lake City Area Integrated Projects (SLCA/IP) power plants and changes in downstream environmental impacts. Thus, although the court's September 29, 1989, order permitted the post-1989 contracts to become effective, neither the post-1989 commitment level nor any alternative commitment level could be implemented until Western completed an EIS. Accordingly, current levels of commitment are based on 1978 levels with minor adjustments established by Western and the court. This EIS is intended to meet the requirement of the court order for an EIS that includes an assessment of downstream impacts of power generation at SLCA/IP facilities.

The power marketing criteria specify the total long-term firm (LTF) capacity and energy Western sells as well as the allocation of LTF sales among Western's preference customers. The criteria also specify the terms and conditions of contracts and establish the basis for other services. As part of the EIS process, Western selected several LTF commitment-level alternatives to analyze the impacts of firm commitments on the human and natural environment. This document focuses on customer utility systems. The LTF capacity offered to customers under these alternatives ranges from 550 to 1,450 MW, and annual LTF energy commitments range from 3,300 to 6,010 GWh. Several supply-side scenarios that constrain the operations of SLCA/IP hydropower plants were also analyzed. Operational constraints ranged from no flexibility at any hydropower plant (i.e., a constant generation level for all hours in a month) to a high degree of flexibility (i.e., minimal operational restrictions). Various combinations of commitment-level alternatives and operational scenarios were analyzed in detail. The effects of hydropower conditions (i.e., dry, normal, and wet) on each combination were also investigated.

The EIS alternatives will affect both customers that receive LTF capacity and energy and customers that purchase spot market energy from Western. In general, the electricity that Western sells annually will remain constant among the alternatives, but the distribution of monthly and hourly energy sales will vary. As a result of changes in commitment-level and hydropower plant operations, Western's customers may need to alter (1) use of electric generators, (2) purchases and sales of electricity, (3) demand-side management (DSM) programs, and (4) capacity expansion paths.

Because some alternatives stipulate a higher level of LTF commitments than the total operable capacity of SLCA/IP hydropower plants, Western must augment its resources with LTF purchases. Western's participation in spot market activities will also be affected by alternative commitment levels.

This report describes the modeling methods used to simulate the production of electricity and the expansion of capacity for utility systems directly affected by alternatives specified in Western's power marketing EIS. Cost estimates and other impacts for each alternative are also presented. Power system modelers at Argonne National Laboratory (ANL) analyzed several areas related to electric utility systems: historical loads, hourly demand projections, utility dispatch and supply expansion, spot market transactions, and hydropower plant operations. Other aspects of electric utility systems such as DSM, load forecasting (Cavallo et al. 1995), utility finances (Bodmer et al. 1995), and emissions of environmental residuals (Chun 1995) were also analyzed as part of the EIS process.

Figure 1 provides an overview of the modeling methods used to evaluate the power systems for the power marketing EIS. The modeling system was designed so that decisions, such as capacity expansion plans, are made at the utility level. Short-term economic transactions between utility systems are made through spot market simulations.

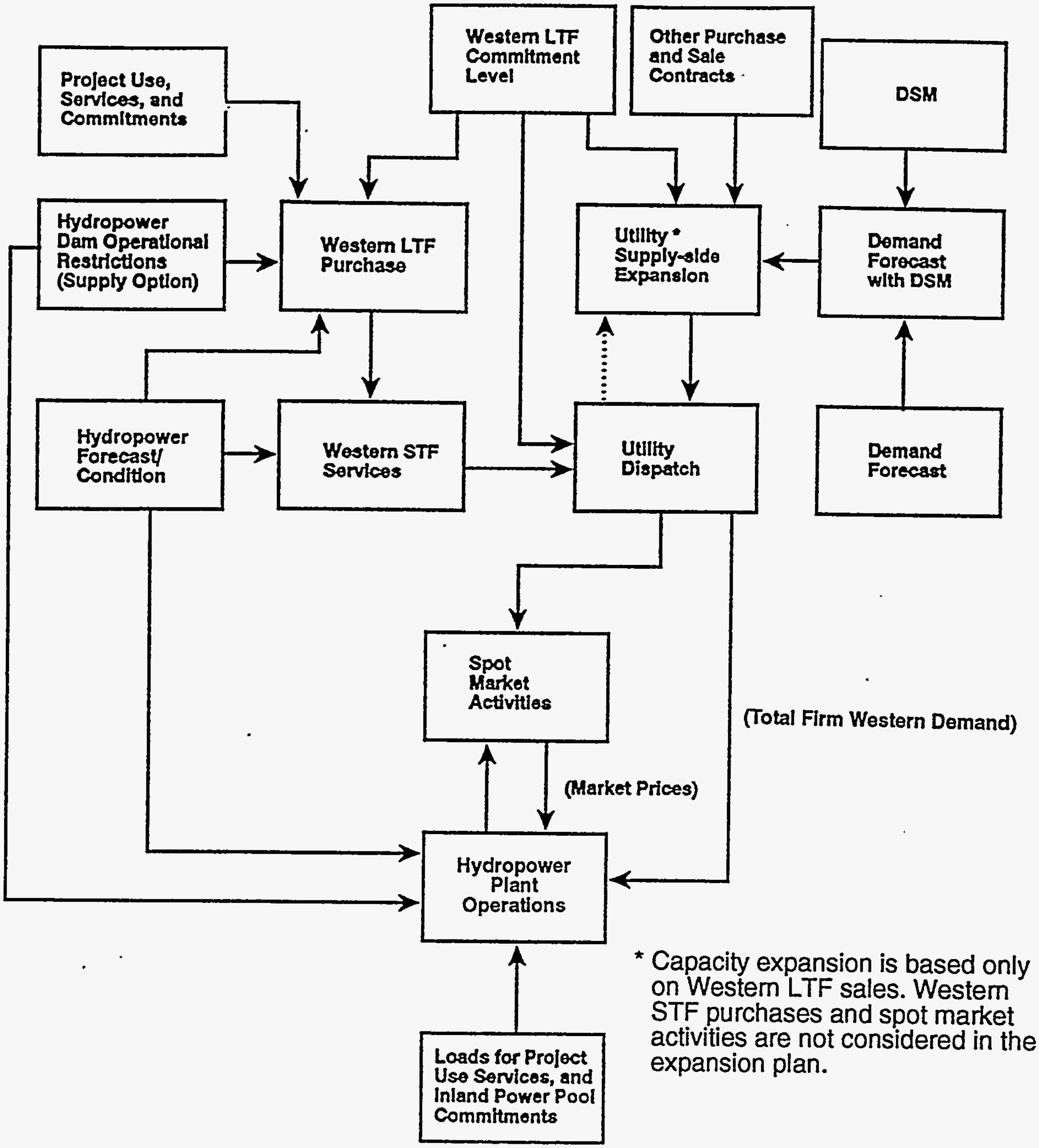

FIGURE 1 Flow Diagram of the Modeling Approach Used for the Western Power Marketing EIS

As shown in Figure 1, LTF purchasing programs affect the dispatch of electric generating units and capacity expansion paths of Western LTF customers. Changes in Western's LTF commitments also affect the hourly demands for both LTF and short-term firm (STF) energy. Hydropower operational restrictions directly affect the dispatch of SLCA/IP hydropower plants and Western's purchasing programs and sales of energy on the non-firm market.

Most of the modules and computational techniques used by ANL's modeling methodology consist of tools used for previous ANL projects. However, existing modules were tailored for this project, and several new routines were built to address important issues specifically related to the Western EIS. A new modeling framework was also constructed, which allows various modules (both old and new) to interact.

Within the geographic boundaries determined by the study, this analysis measures the overall economic impacts of various commitment-level alternatives and hydropower plant operational scenarios. However, it also generally indicates system types (i.e., investor-owned or Western customers) that may have an economic gain or loss as a result of changes in Western's programs.

2 SLCA/IP HYDROPOWER RESOURCES

Western's Salt Lake City Area Office is responsible for marketing the capacity and energy from the Colorado River Storage Project (CRSP), and the Seedskedee, Collbran, Rio Grande, and Provo River projects. These projects, with the exception of Provo River, were aggregated to form the SLCA/IP. Table 1 summarizes the characteristics of each of the integrated projects. The CRSP power plants, together with the Fontenelle power plant, provide approximately 98% of SLCA/IP's capacity of 1,822 MW. Fontenelle is the only Seedskedee project power plant. A more detailed description of SLCA/IP power plants is provided in Veselka et al. (1995).

The following sections briefly describe the projects that make up the SLCA/IP. Characteristics of the projects are given, including plant capacity, reservoir storage capacity, and maximum and minimum flow restrictions.

2.1 COLORADO RIVER STORAGE PROJECT

The CRSP was authorized by a special congressional act on April 11, 1956. The legislation authorized development of facilities for use in land reclamation, flood control, and generation of electricity. The purpose of the act was to develop the water resources of the Upper Basin.

The CRSP consists of four storage units: Glen Canyon on the Colorado River in Arizona near the Utah border, Flaming Gorge on the Green River in Utah near the Wyoming border, Navajo on the San Juan River in New Mexico near the Colorado border, and Wayne N. Aspinall (formerly Curecanti) on the Gunnison River in west central Colorado. Power plants associated with Aspinall are Blue Mesa, Morrow Point, and Crystal. These projects regulate the flow of the Colorado River in such a way that irrigation, municipal, industrial, and other water-use developments in the Upper Colorado River Basin can take place, while maintaining water deliveries to the Lower Basin, as required by the Colorado River Compact.

2.1.1 Glen Canyon Dam

The Bureau of Reclamation (Reclamation) built Glen Canyon Dam on the Colorado River between 1956 and 1964. The dam's total storage capacity is 27 million acre-feet, with a live storage capacity (to generate power) of 25 million acre-feet. Eight generating units at Glen Canyon provide a total capacity of 1,356 MW; the first two units began generating electricity in September 1964, and the eighth unit began generating electricity in February 1966. Without considering the limitations due to interim test releases, Glen Canyon comprises nearly 75% of the entire generating capacity of CRSP. Each unit was rewound and uprated by April 1987, adding about 200 MW of operating capacity to the power plant.

TABLE 1 Operating Characteristics of SLCA/IP Hydropower Generating Units

Plant Name	No. of Units	Total Generating Capacity (MW)	Total Storage Capacity (acre-feet)	Live Storage Capacity (acre-feet)	10-Year Average (1980-1990) Gross Generation (MWh)	Minimum Flow below Power Plant (cfs)	Maximum Power Release (cfs)	Under Automatic Generation Control
Glen Canyon	8	1,300[a]	27 million	25 million	5,800,000	3,000 summer 1,000 winter	31,500[a]	Yes
Flaming Gorge	3	140[b]	3.79 million	3.75 million	540,000	800	4,900[c]	Yes
Blue Mesa	2	88[b]	940,800	829,000	292,000	0	3,000	Yes
Morrow Point	2	155[b]	117,190	117,025	398,000	0	5,000	Yes
Crystal	1	33[b]	25,273	17,573	189,000	300	1,700	Yes
Navajo	0	0	1.71 million	1.70 million	0	NA[d]	NA	No
Fontenelle	2	12[b]	345,400	150,500	39,200	400	1,700	No
Elephant Butte	3	24[b]	2,109,423	2,109,423	112,000	0	2,250	No
Upper Molina	1	9	0	0	37,000	NA	NA	Yes
Lower Molina	1	5	0	0	22,000	NA	NA	Yes

[a] The installed capacity is 1,356 MW. The capacity has been limited to 1,300 MW because the maximum power release was limited to 31,500 cubic feet per second (cfs). With interim test release constraints, the capacity is limited to 740 MW at present reservoir elevations, with a maximum release of 20,000 cfs. Interim release minimum is 5,000 cfs at night and 8,000 cfs from 7 a.m. to 7 p.m.

[b] Based on maximum output level as reported by outputs from the Colorado River Simulation System (CRSS) model. Installed capacities are given in Veselka et al. (1995).

[c] The maximum power release is approximately 4,900 cfs; however, bio-compliance regulations significantly reduce the maximum allowable release, which varies by season and hydropower condition (Yin et al. 1995).

[d] NA denotes not applicable.

Because of public concern, the maximum release was administratively restricted to 31,500 cubic feet per second (cfs) (with a maximum operating capacity of 1,300 MW at full reservoir) until impacts associated with uprated unit performance and dam operations are completely analyzed in the ongoing environmental studies.

From 1980 (when Lake Powell filled for the first time) through 1990, the gross generation averaged approximately 5,800,000 MWh/yr. The minimum generation associated with the minimum annual objective release of 8.23 million acre-feet is approximately 3,700,000 MWh at present reservoir elevations. Interim test release constraints at Glen Canyon, imposed by Reclamation on August 1, 1991, specify a maximum release rate of 20,000 cfs, which effectively reduces the plant's maximum operating capacity by approximately 33%.

2.1.2 Flaming Gorge Dam

Flaming Gorge Dam created Flaming Gorge Reservoir, which has a total storage capacity of 3.79 million acre-feet, with a live storage capacity of 3.75 million acre-feet. The power plant at Flaming Gorge has three generating units that came on-line in November 1963. Together, these units had a maximum total generating capacity of 132 MW. The units were uprated about three years ago with a combined operating capacity of about 145 MW. This is somewhat less than the name plate capacity of 151.95 MW (i.e., 50.65 for each unit). From 1980 to 1990, the gross generation averaged approximately 540,000 MWh/yr.

2.1.3 Blue Mesa Dam

The Blue Mesa Dam is part of the Wayne N. Aspinall Project. The power plant at Blue Mesa began generating electricity in September 1967 and consists of two 36-MW generating units. The uprate of the units to the present 44-MW level was completed in 1989, giving a combined capacity of 88 MW. From 1980 to 1990, the gross generation averaged approximately 292,000 MWh/yr. The Blue Mesa Reservoir has a total storage capacity of 940,800 acre-feet, with a live storage capacity of more than 829,000 acre-feet.

2.1.4 Morrow Point Dam

The Morrow Point Dam is also part of the Aspinall Project. The power plant at Morrow Point began generating electricity in December 1970 and consists of two units, which presently have a combined equivalent maximum operating capacity of 155 MW. From 1980 to 1990, the gross generation averaged approximately 398,000 MWh/yr. The Morrow Point Reservoir has a total storage capacity of 117,190 acre-feet, with a live storage capacity of 117,025 acre-feet.

2.1.5 Crystal Dam

The Crystal Dam is also part of the Aspinall Project. The power plant at Crystal Dam has one 33-MW unit that began generating electricity in August 1978. The Crystal Reservoir has a total storage capacity of 25,273 acre-feet, with a live storage capacity of 17,573 acre-feet. The reservoir serves as a reregulation structure for Morrow Point releases to the Gunnison River. From 1980 to 1990, the gross generation averaged approximately 189,000 MWh/yr.

2.1.6 Navajo Dam

The Navajo Dam created the Navajo Reservoir, which has a total storage capacity of 1.71 million acre-feet, with a live storage capacity of 1.70 million acre-feet. The City of Farmington has constructed a two-unit 32-MW power plant at this site. This power plant is not part of SLCA/IP resources.

2.2 SEEDSKEDEE PROJECT

The power plant at the Fontenelle Dam is the only one associated with the Seedskedee Project. Fontenelle consists of two units that have a combined maximum operating capacity of 12 MW. The reservoir has a total storage capacity of 345,000 acre-feet. From 1980 to 1990, the gross generation averaged approximately 39,200 MWh/yr. However, because of repairs to the dam, power was not generated from 1986 through 1988. The long-term average gross generation (1968-1990) is 52,000 MWh/yr.

2.3 RIO GRANDE PROJECT

The Rio Grande Project, which is 125 miles north of El Paso, Texas, began operation in February 1905 when a congressional act (Rio Grande Reclamation Project, February 25, 1905) established a much-needed irrigation project on the Rio Grande River in south central New Mexico and west Texas. The only dam with generating facilities at the Rio Grande Project is Elephant Butte Dam, which was completed in 1916. The power plant at Elephant Butte Dam (constructed after completion of the Caballo Dam, approximately 25 miles downstream) began generating electricity in 1940 and consists of three generating units (about 8 MW per unit), which have a combined operating capacity of 24 MW. From 1980 to 1990, the annual gross generation averaged approximately 112,000 MWh/yr.

2.4 COLLBRAN PROJECT

The Collbran Project, located in west central Colorado about 35 miles northeast of Grand Junction, was authorized by Congress in July 1952 (the Collbran Project Act of July 3, 1952). The project consists of the Vega Dam, which is located in Colorado's Rocky Mountains on Plateau Creek and stores 34,000 acre-feet of water. The project develops a major part of the unused water of Plateau Creek and its principal tributaries for irrigation uses as well as for flood control and recreational, fish, and wildlife benefits. It includes several diversion dams, 34 miles of canal, 18 miles of pipeline, and two power plants: Upper Molina and Lower Molina.

2.4.1 Upper Molina Dam

The Upper Molina Dam power plant consists of one generating unit, with a total operating capacity of 9 MW (one unit at 8,640 kW). The penstock has a maximum capacity of 50 cfs. The power plant has an effective head of 2,490 ft. The plant began generating electricity in December 1962 and was historically operated as a run-of-river plant. However, since May 1993, it has been operated as a peaking power plant. From 1980 to 1990, the gross generation averaged approximately 37,000 MWh/yr.

2.4.2 Lower Molina Dam

The Lower Molina Dam power plant consists of one generating unit, with a total operating capacity of approximately 5 MW. The penstock has a maximum capacity of 50 cfs. The power plant has an effective head of 1,400 ft. This plant also began generating electricity in December 1962 and was historically operated as a run-of-river plant. However, since May 1993, it has been operated as a peaking power plant. From 1980 to 1990, the gross generation averaged approximately 22,000 MWh/yr.

2.5 PROVO RIVER PROJECT

Western is also responsible for marketing capacity and energy from the Provo River Project. It consists of only one small power plant, Deer Creek, with a maximum output capacity of approximately 5 MW. Annual generation for Deer Creek is about 25 GWh. Because this project is not part of the integrated projects, it was not considered in this analysis.

3 LARGE ELECTRIC UTILITY SYSTEMS ANALYZED

Commitment-level alternatives and hydropower operational limitations will affect Western's firm and non-firm customers. Therefore, detailed production cost simulations were performed, and least-cost capacity expansion paths were determined for several electric utility systems in the SLCA marketing area. As shown in Figure 2, the marketing area covers six western states: Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. The marketing area is divided into northern and southern divisions because at the time the power plants were constructed, the demand in the northern division was insufficient. Therefore, a small percent (about 10%) of the SLCA/IP resources was marketed to the southern division. Utilities in this marketing area differ significantly in size, type, and resources.

Utilities range in size from small municipal systems to large investor-owned utilities that have service territories spanning several states. In general, larger utilities own and operate generating resources and have extensive electric transmission and distribution capabilities. A few of the larger systems also have load control responsibilities. Smaller systems have limited or no generating resources and principally rely on purchases to meet load requirements.

FIGURE 2 Western's SLCA Power Marketing Area

Western currently serves more than 180 LTF customers. However, most of these utilities are small, and all are requirements utilities (requirements utilities are utilities that have no generating resources and must rely on purchases to serve their loads). Therefore, it is not appropriate to simulate a utility dispatch and determine least-cost capacity expansion paths for these systems. This report focuses on the larger utility systems affected by commitment-level alternatives. The impacts of EIS alternatives on both large and small systems have been studied in detail by financial analysts (Bodmer et al. 1995). A utility was selected for detailed systems analysis either (1) because it is a Western LTF customer that is relatively large in size compared with other Western LTF customers and has a significant allocation (or its members have a significant allocation) of Western capacity and energy, or (2) because it is a large investor-owned utility that purchases from Western on the spot market and is interconnected with Western LTF customers.

3.1 LARGE WESTERN LONG-TERM FIRM CUSTOMERS

Table 2 lists Western's 12 LTF customers that were studied in detail. Electricity generating capacities shown in the table were obtained from the *Electrical World Directory of Electric Utilities* (1992) and may differ from the confidential data used in this study. The 12 utility systems and their member systems account for more than 85% of Western's LTF capacity and energy commitments under the No Action Alternative. This alternative represents the base-case condition under the 1978 marketing criteria, as described in Section 4. Because the Deseret Generation and Transmission Cooperative provided limited data and sufficient data were not available from public sources, a less detailed analysis was performed on this system.

Table 2 shows that approximately 68% of the 9,028.1 MW of generating capacity of Western's 12 large customers use coal as their primary energy source. Generators that primarily use oil and gas comprise 21% of the total. In addition to the resources listed in Table 2, large LTF utility customers had approximately 1,210 MW of SLCA's LTF capacity allocations under the No Action Alternative. Some of these systems also received capacity allocations from Western's Loveland Area Office (LAO) and Western's Phoenix Area Office and had LTF contracts with other utility systems. As described in detail in Section 4.2, Western's SLCA LTF capacity allocation for these systems is reduced to 470 MW under the lowest LTF capacity alternative. The following sections briefly describe each of the 12 utility systems. Tables in Appendix A summarize key features of each large Western customer, and Appendix B provides generating unit information.

3.1.1 Arizona Power Pooling Association

The Arizona Power Pooling Association (APPA) is a state utility formed through the alliance of four utility systems: the Arizona Electric Power Cooperative, Inc.; City of Mesa; Electrical District No. 2; and the San Carlos Irrigation Project. The APPA is headquartered in Benzon, Arizona.

TABLE 2 The 12 Large Western Long-Term Firm Customers Modeled in Detail

Utility Name	Headquarters Location[c]	Type	Electric Generating Capacity[a,b] (MW) Coal	Oil/Gas	Hydro[d]	Other
Arizona Power Pooling Association	Arizona	State	350.0 (66.0%)	170.0 (32.1%)	10.0 (1.9%)	0.0 (0.0%)
Colorado-Ute Electric Association, Inc.	Colorado	Rural electric cooperative	1,143.0 (98.9%)	0.0 (0.0%)	12.5 (1.1%)	0.0 (0.0%)
Colorado Springs Utilities	Colorado	Municipal	505.0 (84.8%)	84.2 (14.1%)	6.0 (1.0%)	0.0 (0.0%)
Deseret Generation and Transmission Co-operative[e]	Utah	Rural electric cooperative	518.0 (100%)	0.0 (0.0%)	0.0 (0.0%)	0.0 (0.0%)
Farmington/Aztec Electric Utilities	New Mexico	Municipal	42.2 (40.4%)	32.2 (30.8%)	30.0 (28.7%)	0.0 (0.0%)
Plains Electric Generation and Transmission Cooperative, Inc.	New Mexico	Rural electric cooperative	250.0 (84.3%)	46.5 (15.7%)	0.0 (0.0%)	0.0 (0.0%)
Platte River Power Authority	Colorado	Federal	409 (100%)	0.0 (0.0%)	0.0 (0.0%)	0.0 (0.0%)
Salt River Project Agricultural Improvement and Power District	Arizona	State	2,069.1 (47.4%)	1,392.3 (31.9%)	238.2 (5.5%)	666.4[f] (15.3%)
Tri-State Generation and Transmission Association, Inc.	Colorado	Rural electric cooperative	602.8 (85.8%)	100.0 (14.2%)	0.0 (0.0%)	0.0 (0.0%)
Utah Associated Municipal Power Systems[g]	Utah	State	146.9 (62.1%)	67.8 (28.3%)	25.5 (10.6%)	0.0 (0.0%)
Utah Municipal Power Agency	Utah	State	56.0 (63.7%)	18.0 (20.5%)	3.9 (4.4%)	10.0[h] (11.4%)
Wyoming Municipal Power Agency	Wyoming	State	22.6 (100.0%)	0.0 (0.0%)	0.0 (0.0%)	0.0 (0.0%)
Total			6,114.6 (67.7%)	1,911.0 (21.2%)	326.1 (3.6%)	676.4 (7.5%)

[a] Only includes ownership share of jointly owned units and units on-line as of December 31, 1992.

[b] Contract rate of deliveries from Western and utility system demand statistics are shown in Table 6.

[c] Utilities service territories are also in the state. However, some utilities such as Tri-State G&T have service territories in multiple states.

[d] Includes pondage, run-of-river, and pumped storage units.

[e] Because of its relatively small size, the nature of its supply-side resources, and lack of data, capacity expansion and dispatch runs were not performed on this system. However, a detailed financial analysis was performed on this system (Bodmer et al. 1995).

[f] Uses nuclear fuel.

[g] Generating capacities also obtained from Hunter Project Refunding Reserve Bonds, 1992 Series.

[h] Uses geothermal energy.

Source: *Electrical World Directory of Electric Utilities* (1992). Cross-referenced with *Summary of Estimated Loads and Resources as of January 1, 1991* (WSCC 1991b) and *Inventory of Power Plants in the United States 1992* (DOE 1992b).

The APPA is one of the largest public power utility systems analyzed in this study. In 1991, it recorded a system peak load of about 647.6 MW, with associated energy sales of approximately 3,667.8 GWh. The power pool is a thermal-based system, with coal-based capacity constituting about 66% of the total supply resources in 1991. Natural-gas-fueled sources make up about 32%. The system's total capacity was 530 MW. The SLCA LTF allocation under the 1978 marketing criteria, satisfied about 7% of the system peak load in 1991 and approximately 3% of its corresponding energy sales.

3.1.2 Colorado-Ute Electric Association, Inc.

Colorado-Ute Electric Association, Inc. (Colorado-Ute), was a bulk producer of electric power with headquarters in Montrose, Colorado. The mission of this nonstock, nonprofit rural electric cooperative founded in 1941 was to provide quality electric service to its 14 retail distribution cooperatives. Colorado-Ute had about 240,000 retail customers and a service area of approximately 50,000 square miles (i.e., more than half the area of the state of Colorado).

Colorado-Ute was the second largest system in Colorado. However, since the power marketing EIS began, Colorado-Ute ceased operations. Its service territories and assets were divided among the Tri-State Generation and Transmission Cooperative, Public Service Company of Colorado, and PacifiCorp. For this study, Colorado-Ute is treated as a separate, intact utility system because at the time data were compiled, the ultimate fate of Colorado-Ute had not been determined.

In 1990, Colorado-Ute's system peak load reached 773 MW, with corresponding energy sales of 6,745.7 GWh. During the same year, its supply capacity totaled 1,156 MW, of which about 99% was coal and 1% was hydropower. In addition to its own resources, Colorado-Ute had an LTF contract to purchase power and energy from SLCA and LAO. The SLCA LTF allocation under the 1978 marketing criteria served approximately 4% of Colorado-Ute's system peak load and about 2% of its energy sales in 1990.

Transmission lines in Colorado-Ute's transmission system included 69-, 115-, 138-, 230-, and 345-kV systems, with a combined length of 1,805 circuit-miles. Colorado-Ute was interconnected with neighboring systems and sold surplus power and energy to several utilities.

3.1.3 Colorado Springs Utilities

The City of Colorado Springs Utilities (Colorado Springs) is a municipal utility system serving a population of approximately 318,000 in the cities of Colorado Springs, Manitou Springs, Security, Wisefield, and Green Mountain, Colorado.

In terms of system load, Colorado Springs is one of the largest public power utilities included in the study. In 1991, it registered a system peak load of 532 MW and energy sales of 3,007.7 GWh. During the same year, its installed capacity of 595.2 MW was made up mainly of coal-based capacity. Specifically, its supply resources consisted of 85% coal, 14% natural gas, and 1% hydropower.

Colorado Springs' LTF contracts include a capacity and energy purchase agreement with SLCA and LAO. The SLCA LTF allocation under the 1978 marketing criteria served approximately 13.2% of its system peak load and about 6% of its energy sales in 1991.

In addition to Western, Colorado Springs has major interconnections with the Public Service Company of Colorado. Colorado Springs' transmission system operates at 13-, 35-, 115-, and 230-kV levels. The utility is involved in all three aspects of general utility operation: generation, transmission, and distribution.

3.1.4 Deseret Generation and Transmission Co-operative

The Deseret Generation and Transmission Co-operative (Deseret) is a rural electric cooperative based in Sandy, Utah. Deseret is engaged in the wholesale production and transmission of electric power serving six distribution cooperatives. These member-owner cooperatives include Bridger Valley, Dixie-Escalante, Garkane Power, Flowell Electric, Moonlake, and Mt. Wheeler. Organized in 1977, Deseret is one of the smallest utility systems covered by the present study (Deseret 1990). Its system peak load in 1991 was about 244.7 MW, with a total energy sales of 1,507.5 GWh. Coal-based generation is the system's predominant supply resource. The organization owns 96.25% of the 425-MW Bonanza coal-fired power plant and 25.11% of the 400-MW Hunter-2 coal-fired unit. Deseret's transmission system operates at 115 and 345 kV, with a combined length of about 290 circuit-miles.

Under the 1978 marketing criteria, the SLCA LTF allocation served about 49% of the system peak load in 1991 and about 36% of its annual energy sales. Historically, Deseret has purchased energy from Colorado-Ute, Utah Associated Municipal Power Systems (UAMPS), Utah Municipal Power Agency (UMPA), Utah Power and Light, Pacific Power and Light, and the Los Angeles Department of Water and Power.

3.1.5 Farmington/Aztec Electric Utilities

Farmington and Aztec Electric Utilities (Farmington/Aztec) are municipal utility systems serving the cities of Farmington, Bloomfield, and Aztec, New Mexico. For this study, Farmington and Aztec were merged and modeled as a single system. The combined system serves a population of approximately 49,000.

In terms of load, Farmington/Aztec is the second smallest system among the 12 large Western customers modeled in this study. In 1990, the utility registered a system peak load of about 89 MW, with energy sales of 476.4 GWh. In the same year, the system's total generating capacity was 104.4 MW, of which 40% was coal, 31% natural gas, and 29% hydropower. The coal capacity comes entirely from a unit co-owned by another utility. The

SLCA LTF allocation under the 1978 marketing criteria served approximately 20% of Farmington/Aztec's system peak load and about 18% of its energy sales in 1990.

The Farmington/Aztec transmission and distribution system operates at 5, 13, 69, and 115 kV. The utility is engaged in generation, transmission, and distribution of electric power.

3.1.6 Plains Electric Generation and Transmission Cooperative, Inc.

Plains Electric Generation and Transmission Cooperative (Plains) is a rural electric utility engaged in the wholesale production and transmission of electric power. Its main office is in Albuquerque, New Mexico. Plains sells energy to 13 wholesale electric cooperatives, which, in turn, distribute electric power to end users. Its mission is to improve business by supplying safe, reliable power to its customers and to optimize the base wholesale rate structure of cooperative members (Plains 1990).

Plains is a medium-size utility in terms of load among the 12 customer utilities included in this study. In 1991, the system peak load was 299 MW, with associated energy sales of 2,144.5 GWh. The utility's load factor averaged about 75% over the last four years. Plain's generating capacity consists of 250 MW from the coal-fired Escalante power plant and 47 MW from natural-gas-fired capacity.

Plains is the second largest SLCA customer among the utilities modeled. The SLCA LTF allocation under the 1978 marketing criteria served about 47% of its 1991 system peak load and about 31% of its corresponding energy sales. The system's transmission network operates at 69, 115, and 230 kV.

3.1.7 Platte River Power Authority

Platte River Power Authority (Platte River) is a federal utility system consisting of the cities of Estes Park, Fort Collins, Longmont, and Loveland, Colorado. Headquartered in Fort Collins, Platte River produces and supplies wholesale electric power to the four member-owner cities, which, in turn, retail the power to consumers (Platte River Power Authority 1990).

Platte River is a purely coal-based system with a total capacity of 409 MW. Part of this capacity is derived from two coal-fired units jointly owned with other utilities. In 1990, the system registered a system peak load of 283 MW, with energy sales of 1,709 GWh. Platte River's transmission system consists of 115- and 230-kV lines spanning 187 circuit-miles.

The utility has LTF purchase contracts with both SLCA and LAO. In 1991, the SLCA LTF allocation under the 1978 marketing criteria served about 45% of its system peak load and about 38% of its total energy sales. Platte River has an LTF sales contract with the Public Service Company of Colorado (Public Service Company of Colorado 1990).

3.1.8 Salt River Project Agricultural Improvement and Power District

The Salt River Project Agricultural Improvement and Power District (SRP) is a state-chartered utility system headquartered in Phoenix, Arizona. Founded in 1903, the organization provides water and power to a service territory covering about 2,900 square miles. Its territory includes parts of the Phoenix metropolitan area and other surrounding communities and Indian reservations. The SRP provides electric power to portions of the cities of Chandler, Glendale, Mesa, Scottsdale, Tempe, and others. The organization serves a population of about 1,200,000.

The utility is one of the two organizations constituting the main Salt River Reclamation Development Project; the other partner is the Salt River Valley Water User's Association. This development project is the oldest and most successful multipurpose reclamation development project in the United States (SRP 1990).

The SRP is the largest of the 12 public power utilities covered in the present study. In 1991, SRP's supply capacity totaled about 4,366 MW, of which 47% was coal, 32% natural gas, 15% nuclear, and 6% hydropower. In addition to its own generation facilities, SRP has an electric service contract with Western to purchase SLCA/IP power and energy. The SLCA allocation under the 1978 marketing criteria was used to meet about 4% of SRP's peak demand in 1991 and approximately 3% of the utility's corresponding energy sales. The utility's peak load in 1991 was 3,373 MW, with associated energy sales of 17,427 GWh.

Additional LTF power purchase contracts include firm allocations from Park-Davis and Hoover Dam made through Western's Phoenix Area Office. The SRP has a long-term contract to sell surplus energy to the city of Mesa, Arizona; Vernon, California; and the San Carlos Irrigation District, Cyprus-Miami Copper Mine, and Arizona Public Service Company.

The SRP transmission system consists of 69-, 115-, 230-, and 500-kV lines spanning 1,797 circuit-miles. Its distribution system operates at 5, 13, and 25 kV. The SRP also has a contractual arrangement with Western, whereby Glen Canyon generation is exchanged for SRP generation at the Craig and Hayden units at Four Corners in New Mexico (SRP 1993).

3.1.9 Tri-State Generation and Transmission Association, Inc.

The Tri-State Generation and Transmission Association, Inc. (Tri-State), is a rural electric cooperative engaged in the wholesale production and transmission of electric power. Tri-State supplies bulk power to 24 member-owner distribution cooperatives throughout Colorado, Wyoming, and Nebraska. It serves a population of about 148,000 in a service territory of 100,000 square miles. The headquarters of the organization is in Denver, Colorado. Founded in 1952, Tri-State's mission is to provide member-owners with reliable, cost-based electricity, while maintaining a sound financial position through effective use of human, capital, and physical resources in accordance with cooperative principles (Tri-State 1991).

Tri-State is one of the largest utilities included in this study. Since the start of the power marketing EIS study, Tri-State has acquired additional capacity and cooperative members as a result of the Colorado-Ute breakup. However, the additions were not included because, at the time data were compiled, the ultimate fate of Colorado-Ute had not been determined.

The generating capacity of Tri-State in 1991 was 702.8 MW, of which 86% was coal and 14% oil. Tri-State's transmission system operates at 115, 230, and 345 kV spanning 2,000 circuit-miles.

Tri-State has LTF purchase agreements with SLCA and LAO. In 1991, the SLCA LTF allocation under the 1978 marketing criteria served about 15% of the system peak and about 16.5% of the corresponding energy sales. Tri-State's peak load in 1991 was 1,675 MW, with associated energy sales of 6,669.2 GWh.

3.1.10 Utah Associated Municipal Power Systems

Headquartered in Sandy, Utah, Utah Associated Municipal Power Systems is a state utility system made up of municipalities, one special service district, and the Heber Light and Power Company (UAMPS 1992). The organization consists of 29 member entities that serve a population of more than 240,000.

The utility is predominantly a coal-based system. In 1991, UAMPS's supply capability was 385 MW, of which 62% was coal, 28% oil and natural gas, and 11% hydropower. The utility owns about 14% of the 1,600-MW coal-fired Inter-Mountain Power Project. It has numerous small hydropower units, the bulk of which have a capacity of less than 3 MW.

The UAMPS is the fourth largest SLCA customer among the utilities modeled in this study. The SLCA LTF allocation under the 1978 marketing criteria served about 56% of the system peak load and approximately 88% of the energy sales in 1991. The utility's load in 1991 was about 312 MW, with associated energy sales of 755 GWh. The utility also has a long-term power purchase agreement with the Idaho Power Company (UAMPS 1992).

3.1.11 Utah Municipal Power Agency

Utah Municipal Power Agency (UMPA) is a state utility system organized on September 17, 1980, pursuant to the provisions of the Utah Interlocal Cooperation Act. Headquartered in Spanish Fork City, Utah, UMPA's main functions include planning, financing, developing, acquiring, constructing, improving, bettering, operating, and maintaining projects for the benefit of its members. The six governmental entities that make up UMPA's membership include Manti City Corporation, Salem City Corporation, Provo City Corporation, Nephi City Corporation, Spanish Fork City Corporation, and the town of Levan. The organization serves a population of about 102,000 (UMPA 1991).

The UMPA is one of the smallest utility systems analyzed in this study. In 1991, it recorded a system peak load of 126 MW, with energy sales of 772 GWh and an annual load factor of about 70%. In 1991, its generating capacity was 88 MW, of which 64% was coal, 21% gas, 11.4% other, and 4.4% hydropower. UMPA's coal-based capacity represents its share of two coal-fired units jointly owned with other utilities. UMPA's transmission system consists of 138- and 345-kV lines spanning 377 circuit-miles. In 1991, the SLCA LTF allocation under the 1978 marketing criteria served about 60% of UMPA's system peak load and approximately 50% of its energy sales.

3.1.12 Wyoming Municipal Power Agency

Wyoming Municipal Power Agency (WMPA) is a state utility system engaged in the wholesale generation and transmission of electric energy. Headquartered in Lusk, Wyoming, WMPA serves eight member cities and an irrigation district. Included in its membership are the cities of Cody, Fort Laramie, Guernsey, Lingle, Lusk, Pine Bluffs, Powell, and Wheatland.

The WMPA is the smallest of the 12 large Western LTF customers. In 1991, its system peak load and energy sales were 31 MW and 170 GWh, respectively. Generating resources during the same year consisted of 22.6 MW of coal-based capacity from the jointly owned Laramie River units 1, 2, and 3. WMPA's transmission system consists of 69-kV lines spanning 7.67 circuit-miles. WMPA has LTF contracts with SLCA and LAO. In 1991, the SLCA LTF allocation under the 1978 marketing criteria served about 23% of its system peak load and 15% of its total energy sales.

3.2 INVESTOR-OWNED UTILITY SYSTEMS

The 12 large LTF customers interact with each other and other utility systems in the regions that do not receive SLCA LTF allocations. To estimate these interactions, five investor-owned utility systems were analyzed in detail. Table 3 lists these systems. Tables in Appendix C summarize key features of each of the investor-owned systems.

3.2.1 Arizona Public Service Company

Arizona Public Service Company (APS) is engaged in the production, purchase, transmission, and distribution of electric power. Based in Phoenix, Arizona, APS serves approximately 1,695,000 people (about 45% of the state's population) located in 11 of the state's 15 counties. In 1991, the system peak load was 3,532 MW, with associated energy sales of 19,986.5 GWh.

The APS is the third largest system among the five investor-owned utilities included in this study. Its total generating capacity at the end of 1992 was about 4,482 MW, of which 45.4% was coal, 29.7% gas, and 24.7% nuclear. The organization has LTF power purchase contracts with PacifiCorp and SRP (submitted to the Arizona Corporation Commission 1991).

TABLE 3 Investor-Owned Utility Systems Modeled in Detail

	Electric Generating Capacity[a] (MW)			
Utility Name	Coal	Oil/Gas	Hydro[b]	Other
Arizona Public Service Company	2,037.0 (45.4%)	1,330.8 (29.7%)	5.6 (0.1%)	1,109.0 (24.7%)
Tucson Electric Power Company	1,204.3 (67.3%)	585.7 (32.7%)	0.0 (0.0%)	0.0 (0.0%)
Nevada Power Company	1,082.0 (62.3%)	654.0 (37.7%)	0.0 (0.0%)	0.0 (0.0%)
PacifiCorp East Division (serves primarily Utah and Wyoming)	5,554.1 (93.4%)	198.6 (3.3%)	169.6 (2.8%)	23.5[c] (0.4%)
Public Service Company of Colorado	2,374.3 (79.2%)	282.0 (9.4%)	340.2 (11.4%)	0.0 (0.0%)
Non-LTF customer total	12,251.7 (72.3%)	3,051.1 (18.0%)	515.4 (3.0%)	1,132.5 (6.7%)
Total of all 17 systems	18,366.3 (70.7%)	4,962.1 (19.1%)	841.5 (3.2%)	1,808.9 (7.0%)

[a] Only includes ownership share of jointly owned units and units on-line as of December 31, 1992.

[b] Includes pondage, run-of-river, and pumped storage units.

[c] Geothermal unit.

The APS transmission network consists of about 5,000 circuit-miles of overhead and underground lines and about 20,000 pole-miles of distribution wires. The network operates at 13, 69, 115, 230, 345, and 500 kV. Most of its tie lines operate at 115 kV and above.

3.2.2 Nevada Power Company

The Nevada Power Company (NPC) serves portions of Clark and Nye counties in southern Nevada. Las Vegas, North Las Vegas, Laughlin, and Henderson are among the towns included in its service territory. Based in Las Vegas, NPC serves a population of about 738,000. NPC is engaged in the generation, transmission, purchase, and distribution of electric power (NPC 1991).

Nevada Power is the second smallest utility among the five investor-owned systems analyzed in this study. In 1991, it registered a system peak load of 2,373 MW, with energy sales of 9,552 GWh.

The company is predominantly a coal-based generation system. About 62.3% of its total supply capacity of 1,736 MW is from coal-fueled units, and 37.7% is from oil and natural gas units. Approximately 42% of NPC's gas-based capacity is from nonutility generation. The utility has an electric service contract to purchase power and energy from Hoover Dam. The Hoover Dam contract was approximately 9% of its total supply capability in 1992. The NPC has a number of units jointly owned with other utilities. The utility operates over 6,000 circuit-miles of transmission and distribution lines. Voltage levels in the system range from 5 to 500 kV.

3.2.3 PacifiCorp East Division

PacifiCorp East Division (PacifiCorp-E) is one of the two divisions of the PacifiCorp Electric Operations Group (PEOG); the other is the Pacific Power Division. PEOG is an investor-owned utility that was formed when Utah Power and Light Company merged with Pacific Power and Light Company (PP&L). PEOG serves customers in seven states, including Utah, California, Montana, Oregon, Washington, Wyoming, and Idaho. PacifiCorp-E is sometimes called the Utah-Wyoming Division because it serves primarily Utah and Wyoming. PacifiCorp-E serves a population of about 1,160,000 (PacifiCorp 1989).

PacifiCorp-E has a number of units jointly owned with other utilities. The organization has major tie lines with at least 12 other utilities. It purchases and sells energy to other utilities in the region. PacifiCorp-E is involved in most aspects of general utility operations, including generation, transmission, purchase, sale, and retail distribution of electric power.

3.2.4 Public Service Company of Colorado

Public Service Company of Colorado (PSCO) is an investor-owned utility system with headquarters in Denver, Colorado. PSCO serves a population of approximately 850,000 in more than 54 towns and cities in Colorado. In 1991, its system peak load was 3,627 MW, with total energy sales of 198,364 GWh.

With a total supply capacity of about 3,000 MW, PSCO is one of the largest investor-owned utilities included in this study. Its transmission system spans about 3,000 circuit-miles of high and extra-high transmission lines and more than 18,000 pole-miles of distribution cables. Since the start of the Western EIS, PSCO has acquired additional generating resources as a result of the Colorado-Ute breakup. The new additions, however, were excluded in this study because, at the time data were compiled, the ultimate fate of Colorado-Ute had not been determined. Under this assumption, the system capacity mix is 79.2% coal, 11.4% hydropower, and 9.4% gas and oil.

The utility's supply capability is further bolstered by power and energy purchases from Tri-State, Colorado-Ute, Platte River, and Basin Electric Power Cooperative under LTF agreements (PSCO 1990). The delivery system operates at 69, 115, 230, 345, and 500 kV for transmission and at 5, 13, and 25 kV for distribution (Public Service Company of Colorado 1990).

3.2.5 Tucson Electric Power Company

Based in Tucson, Arizona, the Tucson Electric Power Company (TEP) is engaged in the generation, purchase, transmission, distribution, and sale of electric energy to wholesale and retail customers (TEP 1991). Its franchise area covers southern Arizona, including the City of Tucson and the towns of Pima and Cochise. It serves more than 700,000 people over a service territory of about 1,155 square miles.

Tucson Electric is the smallest of the five investor-owned utilities included in this study. In 1991, its system peak load was about 1,320 MW, with associated energy sales of 7,126.6 GWh. The utility mainly uses coal and gas. At the end of 1992, about 67% of TEP's supply capacity was coal-based, and the rest was from natural gas units. TEP's total generation capacity is about 1,790 MW.

In addition to its generation facilities, TEP has a long-term purchase contract with Century Power Corporation to buy the output of the 360-MW Springerville coal-fired power plant (TEP 1991). The utility has major interconnections with at least 19 other utilities in the region. The TEP transmission system electric network operates at 69, 115, 230, 345, and 500 kV for transmission and at 5, 13, 25, and 35 kV for distribution.

4 COMMITMENT-LEVEL ALTERNATIVES AND HYDROPOWER OPERATIONAL SCENARIOS

Federally funded hydro projects were constructed for a variety of purposes identified in several authorizing pieces of legislation. The principal purposes of these projects are flood control, navigation, and irrigation. Western's mission is to sell and deliver electricity that is in excess of project uses generated from SLCA/IP power plants that were built as part of certain federal projects. Marketing criteria establish terms by which Western allocates LTF capacity and energy from SLCA/IP. The criteria also set the terms and conditions for LTF contracts and specify contractual types or classes of services other than LTF electric service. These other classes of service include STF electric service, firm and non-firm transmission service, maintenance or breakdown service, economy energy and fuel replacement service, interchange, control area services, and emergency assistance. The criteria also address the allocation methods used to determine individual allocations of power from the SLCA/IP. For a more detailed description of Western's programs and services, see Veselka et al. (1995).

4.1 LONG-TERM FIRM SERVICES

Through its LTF marketing program, Western sells wholesale, long-term, noninterruptible electric services to qualified preference entities. "Long-term" service is a contractual commitment of both capacity and energy for a period greater than 1 year, but less than 40 years. Western determines the amount of LTF electric service that it will sell and has wide discretion as to whom and on what terms it will contract for the sale of Federal power. Western can continue to follow this plan as long as (1) preference is accorded to public bodies defined by statutes and (2) the sale of power does not impair the efficiency of a project for irrigation purposes. Power sales must also encourage widespread use at the lowest possible rates consistent with sound business principles.

Various forms of contract commitments are available, depending on the customer, the duration of the agreement, and the nature of the agreement. The duration of an LTF commitment is established by balancing Western's desire to limit its risks with its desire to ensure a customer has necessary future resources. For the power marketing EIS, it was assumed that LTF contracts under all alternatives would be effective for 15 years, from 1993 through 2007 inclusive. Even though the post-1989 marketing criteria were originally through 2004, for this analysis the starting date of the contract was assumed to be 1993 (not 1989) and the end of the contract delayed. Thus, the contract length corresponds to the length specified in the post-1989 marketing criteria.

The maximum amount of firm capacity that Western commits to provide and that a customer is entitled to receive in the peak month of each season is called the "contract rate of delivery" (CROD). The minimum quantity of energy that a customer is required to take in all hours of a season is called the minimum schedule requirement and is typically expressed as a fraction of a customer's seasonal CROD. The quantity of firm energy that Western must provide and that a contractor is entitled to receive in a season is called the "seasonal energy." Western uses two six-month service seasons: a winter season that extends from the first day of October through the last day of March of the following year, and a summer season that extends from the first day of April through the last day of September. The customer only pays for LTF energy that the utility receives from Western and has the option to purchase less energy than its LTF allocation. Long-term firm capacity is sold on a "take-or-pay" basis.

Historically, the capacity and energy that Western marketed were based on its hydropower resources after adjusting for other obligations such as project use and area load control responsibilities. With the exception of capacity and energy purchased on a pass-through cost basis, this marketing philosophy prevailed through the implementation of the post-1989 marketing criteria. However, to a certain extent, Western's LTF marketing strategy is independent of its hydropower resources; that is, Western has discretion over its LTF programs and can market either more or less LTF capacity and energy than are produced by the SLCA/IP hydropower plants. If Western markets more capacity and energy than that supplied by its hydropower plants, it must make purchases or have some other mechanism in place (i.e., capacity and energy exchanges) to reliably meet its contractual obligations. On the basis of the situation, purchases and other arrangements can be made on an LTF or short-term non-firm basis.

4.2 LONG-TERM FIRM MARKETING ALTERNATIVES

Table 4 shows seven alternative LTF marketing contractual commitments selected by Western for examination under the power marketing EIS. These alternatives span a wide range of capacity and energy amounts that Western could sell on an LTF basis. As indicated in Table 4, four of these alternatives were analyzed in detail: the No Action Alternative, moderate capacity and high energy; Alternative 2, high capacity and low energy; Alternative 4, low capacity and low energy; and Alternative 5, low capacity and high energy. The No Action Alternative was selected for detailed analysis because it represents historical contractual commitment levels and is near the high-capacity and high-energy LTF commitment boundary point, as defined in the power marketing EIS (DOE/EIS-0150D). Alternatives 2, 4, and 5 represent the other potential commitment extremes in terms of LTF capacity and energy; that is, these alternatives are at or near the LTF boundary points of capacity and energy (i.e., intersection of capacity and energy extremes). For a more detailed description of LTF boundaries, see Chapter 2 of the SLCA/IP Electric Power Marketing EIS (DOE/EIS-0150D).

A customer's seasonal allocation of LTF capacity and energy is distributed among months of the season through use of a load patterning method. The load patterning method distributes a customer's monthly energy and capacity deliveries such that they are proportional to the utility's average monthly load. The average monthly load is defined as the average load in terms of MWh for energy and MW for capacity for a particular month (e.g., July) over the previous three years. For example, if a utility is allocated 100 MW of SLCA/IP capacity (i.e., CROD) and has its historic peak summer demand (based on a three-year average) in July, the utility will receive its full CROD (i.e., 100 MW) in that month. The

TABLE 4 Summary of Commitment-Level Alternatives

Alternative Number	Description	Seasonal CROD (MW)		Seasonal Energy (GWh)			Load Factor (%)			Minimum Schedule Requirement (% of Seasonal CROD)
		Winter	Summer	Winter	Summer	Annual	Winter	Summer	Annual	
No Action	Moderate capacity, high energy (1978 criteria)	1,291	1,270	2,672	3,028	5,700	47	54	49	35
1	High capacity, high energy (post-1989 criteria)	1,449	1,351	3,177	2,979	6,156	50	50	50	35
2[a]	High capacity, low energy	1,450	1,450	1,705	1,595	3,300	27	25	26	10
3	Moderate capacity, moderate energy	1,225	1,225	2,067	1,933	4,000	39	36	37	15
4[a]	Low capacity, low energy	550	550	1,705	1,595	3,300	71	66	68	52
5[a]	Low capacity, high energy	625	625	2,732	2,743	5,475	100	100	100	100
6	Moderate capacity, moderate energy	1,000	1,000	2,455	2,295	4,750	56	52	54	33

[a] Commitment-level alternatives analyzed in detail.

amount that the utility receives in the other summer months depends on the ratio of the peak demand in a summer month to the peak demand in July. If the utility's peak demand in July is 1,000 MW, and the demand drops to 950 MW in August, the customer's LTF capacity is reduced to 95 MW (i.e., 95 MW = 100 MW × 950 MW/1,000 MW).

The customer's seasonal energy allocation is distributed over the months in a similar manner. The only difference is that the energy pattern is benchmarked to the utility's total system load for each month instead of by the monthly peak demand. For example, if a utility's system load in July is 50 GWh, and it is allocated 5 GWh of SLCA LTF energy, the customer's energy would be reduced to 4.5 GWh in August when its load drops to 45 GWh (i.e., 4.5 GWh = 5 GWh × 45 GWh/50 GWh).

Table 5 shows Western's LTF capacity and energy on a monthly basis for the four commitment-level alternatives studied in detail. Estimates are average monthly values over the 15-year LTF contract period, from 1993 through 2007 inclusive. Except for Alternative 5 (low capacity, high energy), monthly values are based on seasonal load patterning and on both historic and projected load patterns for the 12 large customers. Seasonal load patterning was performed for each large customer. Results of the large customers were then aggregated. Monthly distributions for small customers were patterned after the aggregate monthly capacity and energy distributions of the large customers.

Because Alternative 5 is based on a 100% load factor, the load patterning method cannot be used in most situations. Therefore, the capacity assigned to each month was set to the monthly CROD, and the monthly energy was based on the monthly capacity and the number of hours in each month.

In the summer, the maximum aggregate LTF capacity commitment occurs in July and equals the summer CROD. However, in the winter, the maximum aggregate capacity commitment occurs in January but is less than the winter CROD. This variation occurs because the 12 large customers have peak loads in different winter months; that is, some systems have a peak demand in December and others have a peak demand in January.

4.2.1 No Action Alternative

The moderate-capacity, high-energy commitment-level alternative, also referred to as the No Action Alternative or as the post-1978 marketing criteria, represents the power marketing strategy effective February 9, 1978 (43 *Federal Register* [FR] 5559) (as revised on February 6, 1984 [49 FR 6603]), through April 1989, when Western had executed all 81 post-1989 marketing criteria contracts. Under the post-1978 marketing strategy, the LTF CROD was 1,291.2 MW in the winter and 1,270.0 MW in the summer. Given the operational flexibility at the time that these criteria were established, these capacity commitments could be satisfied by SLCA/IP hydropower resources under all but the most adverse hydropower conditions. Annual LTF energy commitments of 5,700 GWh were based on average hydropower conditions. This commitment-level alternative was analyzed in detail by power system analysts.

TABLE 5 Total Monthly Western Capacity and Energy Sales as a Function of Commitment-Level Alternative for All Customers

	No Action Alternative		Alternative 2		Alternative 4		Alternative 5	
Month	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)
January	1,266	489	1,422	312	538	312	626	465
February	1,232	417	1,379	266	523	266	626	420
March	1,134	436	1,270	278	482	278	626	465
April	984	445	1,127	236	428	236	625	450
May	1,016	471	1,158	249	440	249	625	465
June	1,180	495	1,341	261	508	261	625	481
July	1,270	583	1,450	306	550	306	625	497
August	1,187	545	1,347	286	512	286	625	497
September	1,153	484	1,310	225	498	255	625	481
October	1,109	422	1,243	269	471	269	626	465
November	1,172	431	1,309	274	496	274	626	450
December	1,265	481	1,420	308	538	308	626	465

Under drier-than-normal hydropower conditions, Western purchased energy to fulfill its LTF energy commitments. Because the No Action Alternative is based on an average hydropower year, additional energy must be frequently purchased in many months. The probability distribution of annual energy releases from SLCA/IP hydropower plants is skewed toward higher energy releases, and energy deficit purchases must be made approximately 62% of the months. Under the post-1978 marketing criteria, energy purchase costs are eventually passed on to customers in the form of higher rates. Costs are shared equally by all LTF customers and blended into the rate. Likewise, revenues from excess energy sales during wet hydropower years are shared by customers through lower customer rates. Table 6 shows SLCA LTF allocations for the 12 large Western customers and the portion of system peak load and total energy sales served by Western purchases.

In terms of percentages, Western serves as little as 3-4% of a utility's system peak load and total sales. However, other systems use Western SLCA LTF allocations of capacity and energy to serve a majority of their sales. In general, utility systems that rely on Western for significant allocations tend to be more adversely affected by reductions in capacity and energy allocations than utility systems that are less reliant on Western. However, other factors such as a system's capacity reserve level, production costs, transmission access, and contractual arrangements also play a large role in the level of impacts experienced as a result of changes in SLCA LTF capacity and energy allocations. System peak load and annual energy sales found in Table 6 were obtained from the *Electrical World Directory of Electric Utilities* (1992). System loads used for detailed analyses are proprietary and therefore cannot be reported. The nonproprietary data are provided here to give the reader an appreciation for the level that customers rely on Western for both capacity and energy.

Historically, Western's operations have resulted in highly fluctuating flows. As discussed in Section 6, a continuation of the 1978 marketing criteria would likely result in a continuation of highly peaking operations without external operational restrictions imposed by Reclamation or internal restrictions imposed by Western.

4.2.2 Alternative 1: Post-1989 Marketing Criteria

The post-1989 power marketing criteria were published in the *Federal Register* on February 7, 1986 (51 FR 4844). The marketing criteria established terms by which Western would allocate LTF capacity and energy from October 1, 1989, through September 30, 2004. Alternative 1 is similar to the No Action (1978 criteria) Alternative with a few exceptions. The commitment level for LTF capacity is slightly higher for Alternative 1 than it is for the No Action Alternative, with 1,351 MW offered in the summer and 1,449 MW offered in the winter. This level translates to an SLCA/IP hydropower exceedance probability level of about 90% (i.e., the hydropower capacity meets or exceeds these levels 9 out of 10 years).

Alternative 1 provides Western with unlimited flexibility on all three types of purchase activities (i.e., LTF, STF, and non-firm). In some cases, all contractors share the expense for this purchased power. In other cases, the expense for purchased power is directly

TABLE 6 Long-Term Firm Allocations under the No Action Alternative for the 12 Large Western Customers

Utility Name	1991 Annual System Peak and Coincidental CROD			1991 Annual Energy Sales		
	System Peak[a] (MW)	CROD[b] (MW)	Western Percent of Peak	Total Sales[a] (GWh)	Western LTF Energy (GWh)	Western Percent of Sales
Arizona Power Pooling Association[c,d]	647.6	45.0	6.9	3,667.8	113.1	3.1
Colorado-Ute Electric Association, Inc.[e]	773.0	33.0	4.3	6,745.7	158.7	2.4
Colorado Springs Utilities[d]	532.0	70.0	13.2	3,007.7	165.8	5.5
Deseret Generation and Transmission Co-operative[c,d]	244.7	120.2	49.1	1,507.5	543.1	36.0
Farmington/Aztec Electric Utilities[c,e]	88.7	18.0	20.3	476.4	87.1	18.3
Plains Electric Generation and Trans. Cooperative, Inc.[d]	298.8	140.0	46.9	2,144.5	673.3	31.4
Platte River Power Authority[d]	282.8	126.0	44.6	1,709.1	641.8	37.6
Salt River Project Improvement and Power District[d]	3,373.0	149.0	4.4	17,427.3	480.9	2.8
Tri-State Generation and Transmission Association, Inc.[d]	1,675.0	252.0	15.0	6,669.2	1,099.1	16.5
Utah Associated Municipal Power Systems[d,f]	312.0	174.0	55.7	755.0	664.3	88.0
Utah Municipal Power Agency[d]	126.0	76.0	60.3	771.8	388.2	50.3
Wyoming Municipal Power Agency[d]	30.8	7.0	22.7	169.5	25.2	14.9
Total	8,384.4	1,210.2	14.4	45,051.5	5,040.6	11.2

[a] Source: *Electrical World Directory of Electric Utilities* (1992).

[b] CROD for utility, peak season.

[c] Sum of individual members.

[d] Based on 1991 loads.

[e] Based on 1990 loads.

[f] Data from Hunter Project Refunding Reserve Bonds, 1992 Series.

reimbursed by a specific customer (i.e., pass-through cost [PTC]). Western purchases both capacity and energy on behalf of its LTF customers. Western can purchase a maximum PTC capacity of 109,000 kW in the winter and 95,000 kW in the summer and a maximum PTC energy of 400 GWh/yr. The costs of PTC capacity and PTC energy are passed on to contractors on a prorated basis. Purchases above 400 GWh are passed on to the customers at a blended rate. A customer may choose not to receive PTC capacity and PTC energy, and Western will reduce the customer's seasonal energy and CROD commitments.

The post-1989 marketing criteria added a new northern division, and splits of LTF capacity and energy between old northern and southern marketing divisions were altered. The new northern division contains new customers and provides a few old northern division customers with an additional, but separate, allocation. Table 7 shows percent splits among various customer types for the post-1978 and post-1989 marketing criteria. In the winter, the southern division receives a slightly higher percentage of the total capacity and energy under the post-1989 marketing criteria relative to the post-1978 marketing criteria. However, under the post-1989 marketing criteria, the southern division's share is about 4.5% less than post-1978 in the summer, when the peak demand occurs in the south.

4.2.3 Other Commitment-Level Alternatives

As shown in Table 4, Western selected several commitment-level alternatives for the power marketing EIS. Except for the No Action Alternative, all alternatives are identical to the post-1989 marketing criteria with the following exceptions: (1) the total LTF capacity commitment, (2) the total LTF energy commitment, and (3) the minimum schedule requirement. The LTF capacity shares for each customer are based on post-1989 marketing

TABLE 7 Capacity and Energy Splits by Customer Group

Marketing Criteria Splits/ Customer Group	Winter		Summer	
	Capacity (%)	Energy (%)	Capacity (%)	Energy (%)
Post-1978				
Southern division	7.04	7.89	20.54	19.96
Northern division	92.96	92.11	79.46	80.04
New customers	0.00	0.00	0.00	0.00
Post-1989				
Southern division	8.45	8.53	15.97	15.97
Northern division	88.21	87.47	80.69	79.93
New customers	3.33	4.00	3.34	4.10

criteria allocations of capacity. The LTF energy allocations are based on each customer's capacity allocation and the annual firm sales load factor specified by the commitment-level alternatives. That is, each customer has the same annual load factor that is equal to the load factor specified by the alternative. This alternative differs from the No Action Alternative and the post-1989 marketing criteria in which each utility system had a different LTF purchase load factor based on individual utility systems' requests for a specific capacity and energy amount, as modified by Western.

4.2.3.1 Commitment-Level Alternative 2

Commitment-level Alternative 2 is a commitment to a high level of LTF capacity (1,450 MW) in both the summer and winter but a low level of annual LTF energy (3,300 GWh). This commitment level has the lowest load factor (26%) and lowest minimum schedule requirement (10%) of all the alternatives. This type of commitment would enable customers to take the highest percentage of their commitment during the on-peak hours, when power is most valuable. Although customers would gain value by purchasing a low load-factor resource, the value of this alternative would be diminished by the low energy commitment. This commitment-level alternative was analyzed in detail by power system analysts.

4.2.3.2 Commitment-Level Alternative 3

Commitment-level Alternative 3 is a commitment to a moderate level of LTF capacity (1,225 MW) in both the summer and winter and a moderate level of annual LTF energy (4,000 GWh). This commitment results in a load factor of 37% and a minimum schedule requirement of 15%, the second lowest load factor and minimum schedule requirement of all the alternatives.

4.2.3.3 Commitment-Level Alternative 4

Commitment-level Alternative 4 is the lowest commitment for LTF capacity (550 MW) in both the summer and winter and annual LTF energy (3,300 GWh). It is based on an assumption of continued adverse water conditions. This commitment level has a load factor of 68%, the third highest of all alternatives. The minimum schedule requirement of 52% is the second highest of all alternatives. Commitment-level Alternative 4 offers the lowest LTF commitment of capacity and energy at a high load factor. This commitment-level alternative was analyzed in detail by power system analysts.

4.2.3.4 Commitment-Level Alternative 5

Commitment-level Alternative 5 is characterized by a low level for LTF capacity (625 MW) in both the winter and summer and a high level for annual LTF energy (5,475 MWh). The load factor and minimum schedule requirement for this alternative are both 100%, indicative of a base-loaded resource. Under this alternative, the customer would have to take energy at the stated capacity at all times in order to meet its purchase commitment. This situation would not allow the customer flexibility to vary the energy it takes to meet varying load requirements throughout the day or over the period of a week or a month. This commitment-level alternative was analyzed in detail by power system analysts.

4.2.3.5 Commitment-Level Alternative 6

Commitment-level Alternative 6 is a commitment to a moderate level of LTF capacity (1,000 MW) in both the summer and winter and a moderate level of annual LTF energy (4,750 GWh). This alternative represents the midpoint of the ranges of capacity and energy boundaries. This commitment level has a load factor of 54%, which is mid-range between a high-load and a low-load resource, and a minimum schedule requirement of 33%.

Table 8 shows capacity and energy allocations for each of the 12 large customers and the four commitment-level alternatives studied in detail. Under Alternative 2, CRODs for most utility systems are higher than those under the No Action Alternative. The largest increase is for Colorado-Ute, which has more than twice the capacity under Alternative 2 as under the No Action Alternative.

4.2.4 Discretionary Energy

Within the limits specified under marketing criteria, a customer has wide discretion on its hourly schedule of LTF energy. Customers have the following major restrictions:

- In any one hour, customers cannot exceed their monthly capacity allocation.
- Customers must schedule a percentage of the seasonal CROD in all hours of the season.
- The total energy scheduled in a month cannot exceed the customer's monthly energy allocation.

Table 9 shows the amount of energy used by customers to satisfy the minimum schedule requirement and the amount that can be used at the customer's discretion. In general, discretionary energy is more valuable to the customer because it can be used during peak demands when energy prices are the highest. Except for Alternative 2, most of the LTF energy sales cannot be used at the customer's discretion. Under Alternative 5, all LTF energy is used to satisfy the minimum schedule requirement.

TABLE 8 Long-Term Firm Capacity and Energy Allocations for the 12 Large Western Customers by Commitment-Level Alternative

		Summer			Winter			
Utility Name	Alternative	CROD (MW)	Energy (MWh)	Load Factor (%)	CROD (MW)	Energy (MWh)	Load Factor (%)	Annual Total (MWh)
Arizona Power Pooling Association	No Action	45.00	87,338	44	11.00	25,755	54	113,093
	2	33.55	36,900	25	16.83	19,956	27	56,856
	4	13.00	36,900	65	6.42	19,956	71	56,856
	5	14.50	63,464	100	7.31	31,712	100	95,176
Colorado Springs Utilities	No Action	15.00	38,250	58	70.00	127,500	42	165,750
	2	17.77	19,524	25	66.23	77,567	27	97,091
	4	6.74	19,524	66	25.12	77,567	71	97,091
	5	7.74	33,994	100	28.86	125,842	100	159,836
Colorado-Ute Electric Association, Inc.	No Action	29.00	74,847	59	33.00	83,900	58	158,747
	2	67.28	74,204	25	69.76	83,601	27	157,805
	4	25.51	74,204	66	26.48	83,601	72	157,805
	5	24.75	108,482	100	24.94	108,719	100	217,201
Deseret Generation and Transmission Co-operative	No Action	120.00	282,898	54	129.00	260,178	46	543,076
	2	130.70	143,642	25	132.60	155,275	27	298,917
	4	49.57	143,642	66	50.27	155,275	71	298,917
	5	57.76	253,462	100	60.07	262,167	100	515,629
Farmington/Aztec Electric Utilities	No Action	18.00	43,146	55	25.00	43,923	40	87,069
	2	24.34	26,782	25	24.32	28,558	27	55,340
	4	9.23	26,782	66	9.22	28,558	71	55,340
	5	10.30	45,018	100	9.66	41,976	100	86,994
Plains Electric Generation and Transmission Cooperative, Inc.	No Action	139.95	334,195	54	183.00	339,150	42	673,345
	2	155.91	171,346	25	174.00	204,373	27	375,719
	4	59.00	171,346	66	66.00	204,373	71	375,719
	5	67.69	297,075	100	78.98	344,766	100	641,841

TABLE 8 (Cont.)

Utility Name	Alternative	Summer CROD (MW)	Summer Energy (MWh)	Summer Load Factor (%)	Winter CROD (MW)	Winter Energy (MWh)	Winter Load Factor (%)	Annual Total (MWh)
Platte River Power Authority	No Action	126.00	297,841	54	198.00	343,996	40	641,837
	2	136.57	150,095	25	179.28	209,963	27	360,058
	4	52.00	150,095	66	68.00	209,963	71	360,058
	5	54.19	237,783	100	64.87	283,134	100	520,917
Salt River Project Agricultural Improvement and Power District	No Action	149.00	362,865	55	46.00	118,065	59	480,930
	2	143.93	158,298	25	64.49	76,506	27	234,804
	4	54.60	158,298	66	24.47	76,506	72	234,804
	5	62.10	272,524	100	27.85	121,430	100	393,954
Tri-State Generation and Transmission Association, Inc.	No Action	252.00	642,600	58	178.72	456,450	58	1,099,050
	2	293.62	322,749	25	221.28	259,617	27	582,366
	4	111.70	322,749	66	84.04	259,617	71	582,366
	5	129.80	569,839	100	100.45	438,519	100	1,008,358
Utah Associated Municipal Power Systems	No Action	122.00	289,680	54	174.00	374,570	49	664,250
	2	137.87	151,573	25	193.43	226,904	27	378,477
	4	52.00	151.573	66	73.00	226,903	71	378,476
	5	62.82	275,686	100	87.93	383,860	100	659,546
Utah Municipal Power Agency	No Action	76.00	190,728	57	79.00	197,486	57	388,214
	2	87.12	95,748	25	96.05	112,492	27	208,240
	4	33.00	95,748	66	36.00	112,492	72	208,240
	5	37.66	165,183	100	41.63	181,621	100	346,804
Wyoming Municipal Power Agency	No Action	5.00	11,718	53	7.00	13,515	44	25,233
	2	5.38	5,916	25	6.9	8,087	27	14,003
	4	2.04	5,916	66	2.62	8,087	71	14,003
	5	2.39	10,497	100	2.99	13,060	100	23,557

TABLE 9 Base and Peak SLCA Capacity and Energy

Alternative	Minimum Schedule Requirement: Energy Use (GWh)	Minimum Schedule Requirement: Percent of Total LTF Energy	Discretionary Energy: Energy Use (GWh)	Discretionary Energy: Percent of Total LTF Energy
No Action	3,925.9	68.9	1,775.8	31.1
2	1,270.2	38.5	2,029.8	61.5
4	2,505.4	75.9	794.6	24.1
5	5,475.0	100.0	0.0	0.0

4.3 OPERATIONAL RESTRICTIONS

To meet the resource requirements for each commitment-level alternative, Western would use either the hydropower generated at each SLCA/IP facility or a combination of hydrogeneration and capacity and energy purchases and exchanges from outside sources. Under all conditions, Western obtains a limited amount of energy from the operation of SLCA/IP power plants. The amounts of energy produced by these power plants basically depend on the amounts of water released from the dams. Monthly water volumes released through CRSP facilities are established by Reclamation in consultation with the Colorado River Basin states.

In general, operational restrictions do not affect the amount of energy produced by SLCA/IP hydropower plants. However, restrictions can affect the timing of energy production on an annual, monthly, and hourly basis. For the power systems analysis, three sets of operational scenarios were examined under each of the four commitment-level alternatives: high-, medium-, and low-flexibility scenarios.[1] Two of these options affect the hourly dispatch of energy, and the third option affects both the monthly and hourly release of energy. The hourly release of water is limited by a minimum release rate, a maximum allowable release rate, maximum hourly changes in water releases (hourly ramp rate limits), and a daily maximum fluctuation of water releases.

Only Glen Canyon Dam, Flaming Gorge Dam, and the Aspinall Unit require the development of operational scenarios for analysis in the power marketing EIS. For all facilities where operations are dictated by irrigation demands, municipal and industrial uses, flood control, or other nonpower purposes, operations are not described, and site-specific

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[1] In the Electric Power Marketing EIS and some of the supporting documents, the dam operational scenarios are referred to differently. The high-flexibility scenario is called Supply Option A, full-flexibility dam operation; the medium-flexibility scenario is called Supply Option B, low-fluctuation dam operation; and the low-flexibility scenario is called Supply Option C, steady-flow dam operation.

environmental analyses are not included because, although Western markets this power, Western does not affect hydrogenation at those facilities. Table 10 summarizes the three operational scenarios examined in this study for each affected SLCA/IP hydropower plant.

These operational scenarios were selected from a larger set of operational modes and potential operational combinations specified in the EIS. These consist of nine modes of operation at Glen Canyon Dam, four modes of operation at Flaming Gorge, and two modes of operation at the Aspinall hydropower plants. Western selected a combination of commitment-level alternatives and operational scenarios (see Palmer and Ancrile 1995).

It was assumed that no additional restrictions would be imposed on any of the hydropower plants at the Navajo, Fontenelle, Elephant Butte, and Molina projects under all of the operational scenarios, because Western does not affect hydrogeneration at those facilities.

4.3.1 High Operational Flexibility

The high-flexibility scenario allows for a wide range of hydropower plant operations at each of the SLCA/IP hydropower plants and represents historical operational constraints before interim flow retention at Glen Canyon Dam. Historical operational restrictions are also imposed on Flaming Gorge and the Aspinall units. However, monthly release volumes at the Aspinall units reflect monthly "research" volumes. Under this scenario, Western can quickly respond to changes in firm loads and readily take advantage of purchase and sales opportunities on the spot market. As shown in Table 10, minimum release rates are only required at Glen Canyon and Flaming Gorge. These minimums are only a small fraction of the maximum release rate — approximately 3-10% for Glen Canyon and 16% for Flaming Gorge. Maximum flow limits at each of the dams represent the maximum physical water release through the turbines. Also, none of the plants has institutional limitations on either hourly or daily ramp rates.

The high-flexibility scenario allows Western to shift hydropower energy sales from off-peak to on-peak periods; that is, Western can purchase energy during the off-peak periods to meet firm loads and save the stored energy for non-firm sales during on-peak periods. Under this scenario, Western can use its hydropower resources such that it approaches a maximum economic value (in terms of electricity sales and value to its LTF customers) of the SLCA/IP hydropower capacity and energy resource potential.

4.3.2 Medium Operational Flexibility

The medium-flexibility scenario is identical to the high-flexibility scenario, except that more stringent limitations are placed on operations at Glen Canyon Dam. Historical operational limitations are assumed at Flaming Gorge and the Aspinall units. Monthly release volumes at the Aspinall units reflect monthly "research" volumes. Because Glen Canyon represents approximately 80% of SLCA/IP capacity and energy resources, these limitations represent a significant reduction in SLCA/IP capabilities and reduce the economic

TABLE 10 Summary of Hydropower Operational Scenarios[a]

Scenario/ Power Plant	Minimum Release Rate (cfs)	Maximum Release Rate (cfs)	Maximum Daily Fluctuation (cfs/d)	Up-Ramp Rate (cfs/h)	Down-Ramp Rate (cfs/h)
High Flexibility					
Glen Canyon	1,000[b] or 3,000[d]	31,500	NR[c]	NR	NR
Flaming Gorge	800	4,900	NR	NR	NR
Morrow Point	0	5,300	NR	NR	NR
Blue Mesa	0	3,700	NR	NR	NR
Medium Flexibility					
Glen Canyon	8,000 or 5,000[e]	20,000[f]	5,000, 6,000, or 8,000[g]	2,500	1,500
Flaming Gorge	800	4,900	NR	NR	NR
Morrow Point	0	5,300	NR	NR	NR
Blue Mesa	0	3,700	NR	NR	NR
Low Flexibility					
Glen Canyon	Steady flow, no fluctuation			0	0
Flaming Gorge	Steady flow, no fluctuation			0	0
Morrow Point	Steady flow, no fluctuation			0	0
Blue Mesa	Steady flow, no fluctuation			0	0

[a] No additional restrictions are imposed on any of the hydropower plants at the Navajo, Fontenelle, Elephant Butte, and Molina projects.

[b] Labor Day to Easter.

[c] NR denotes no restriction.

[d] Easter to Labor Day.

[e] 8,000 (7 a.m.-7 p.m.); 5,000 (all other hours).

[f] During wet years, the maximum flow rate may be exceeded; however, flows during this time must be steady.

[g] Limited to 5,000 cfs/d for months with water releases of less than 6 million acre-feet; 6,000 cfs/d for months with water releases of 6 to 8 million acre-feet; and 8,000 cfs/d for months with water releases greater than 8 million acre-feet.

value of the SLCA/IP hydropower resource. Maximum flow restrictions reduce Glen Canyon's operating capacity by approximately 36%, and ramp rate limitations decrease Western's ability to follow firm loads. Depending on reservoir conditions, the up-ramp rate constraint translates into about 90 to 105 MW/h and the down-ramp rate, 54 to 65 MW/h. Depending on Reclamation's monthly release levels and reservoir conditions, maximum daily fluctuations are limited to approximately 185 to 340 MW/day. Under dry hydropower conditions, ramp rate constraints will not permit Western to reach the 20,000-cfs maximum flow constraint on a daily basis and further reduce Glen Canyon Dam's operating capacity. When flexibility at Glen Canyon is reduced, operations at other SLCA/IP hydropower plants can, at times, fluctuate more frequently and more rapidly.

Under the medium-flexibility scenario, non-firm energy sales during peak load hours — when prices are high — are limited. As described in Section 6, the loss in operational flexibility, at times, forces Western to purchase and sell energy to follow firm loads. In addition, higher minimum schedule requirements mandate higher energy releases during off-peak hours when it has a lower economic value. This plan reduces the amount of hydropower plant energy available for generation during on-peak hours.

4.3.3 Low Operational Flexibility

Under the low-flexibility scenario, all SLCA/IP power plants have steady flows. Relative to the high- and medium-flexibility scenarios, monthly energy releases at Glen Canyon Dam are also lower in peak demand months such as January and July and higher in low demand months. Western does not have the ability to follow firm load and to shift power plant energy releases from off- to on-peak hours. Under most situations, Western must either purchase energy to serve firm loads or sell energy on the non-firm market when hydropower generation exceeds firm loads. Releases at Flaming Gorge assume compliance with the "biological opinion" constraints.

In contrast to the high-flexibility scenario, the low-flexibility scenario minimizes Western's ability to fully use SLCA/IP hydropower resources. The value of SLCA/IP resources in terms of operating capacity and energy is substantially reduced.

4.4 EFFECTS OF OPERATIONAL SCENARIOS ON MONTHLY ELECTRICITY GENERATION AND SEASONAL OPERATING CAPACITY

This section describes the models and methods used to project SLCA/IP operating capacity and energy. The CRSS model and the geometric algorithm are used to estimate the CRSP and the Seedskedee projects. Projections for the Collbran and Rio Grande projects are based on simple historical generation averages. Projections of SLCA/IP hydropower plant capabilities in terms of capacity and energy are needed because these resources are expected to change in the future. Currently, SLCA/IP hydropower reservoirs are low and will likely increase in the near term (i.e., up to the year 2000). However, in the long term (i.e., after the year 2000), SLCA/IP hydropower plant capabilities are projected to decrease because water use for nonenergy purposes, such as irrigation and consumption by municipalities, is expected to increase. Changes in operational restrictions and monthly water release volumes will alter the level of operating capacity from SLCA/IP hydropower plants.

4.4.1 Projection of CRSP and Seedskedee Hydropower Plants

The CRSS estimates hydropower plant capacity and energy for CRSP and the Seedskedee Project. Reclamation developed this modeling system, which is a set of multipurpose modules, to study various scenarios. The system has analyzed hydropower-related issues, including flood control, irrigation, municipal and industrial water use, hydropower capacity and energy, water quality (i.e., salinity), recreation, and fish and wildlife. While the CRSS does not optimize the value of hydropower capacity and energy, it does project future monthly hydropower plant capabilities in probabilistic terms.

Designed as a long-term planning model for the Colorado River Basin with a projection of 150 years, CRSS forecasts monthly maximum water releases, reservoir elevation levels, salinity, hydropower plant capacity, and hydropower plant energy. Projections are made on the basis of initial reservoir conditions; anticipated water depletions due to municipal, industrial, and irrigation usage; scheduled generator outages; and historical hydro flow patterns. The modeling system considers evaporation rates, bank storage, and snow pack. Simulation results reflect Reclamation's planning for maintenance at all CRSP facilities on a monthly basis. The CRSS model also incorporates "law of the river" restrictions, including the Colorado River Compact, the Upper Colorado River Basin Compact, and the Mexican Water Treaty. For this study, Reclamation performed CRSS model runs, then supplied these runs to ANL via Western.

For each month simulated, CRSS produces 85 estimates of maximum capacity and energy per hydropower plant. Each estimate is based on a different historical hydro flow trace. A hydro flow trace is a historical sequence of water flows. For example, the first trace input into CRSS is hydro conditions that occurred between 1906 and 1991, and the second trace is based on hydrology that occured in 1991 (first trace value) and hydrology between 1906 and 1990. The third trace consists of hydro conditions for 1991 and 1992 (first two trace values) and hydrology between 2006 and 1989. The model uses 85 different traces. Estimates of capacity and energy are rank ordered to construct probability distributions of capacity and energy by hydropower plant for each month of the study; that is, CRSS results were sorted from highest to lowest and assigned a probability of occurrence.

Because the shortest simulation time in CRSS is one month, the modeling system does not currently account for some of the restrictions specified by an operational scenario; that is, maximum capacity estimates from the CRSS model are based solely on monthly values of hydrologic head, and CRSS does not consider the effects of constraints such as hourly and daily ramp rates. Therefore, a geometric algorithm, along with operational constraints, was used to approximate the operating capacity at each CRSP hydropower plant.

The objective of the geometric algorithm is to estimate the maximum generation level that can be achieved for a specified time for each peak day in a month. The algorithm accounts for flow restrictions at hydropower plant sites, including limits on up-ramp and down-ramp rates, maximum daily fluctuations, and minimum and maximum flow rates. The geometric algorithm also recognizes Sunday as an off-peak period and accounts for the energy that can be released in each month and the time that the operating capacity must be available during on-peak periods. As depicted in Figure 3, the geometric algorithm uses a rectangle to represent the minimum flow requirement and a trapezoid to represent the amount of energy that can be used for serving peak loads. This analysis assumed that peak generation levels must be maintained for four hours during the time of system peak load. This assumption is consistent with the Western Systems Coordinating Council (WSCC) definition of dependable capacity.

When required, the geometric algorithm is run on a plant-by-plant basis for all 85 traces per month. Because of the large number of runs required, the algorithm was run for three projection years — 1992, 1998, and 2010. The year 1992 was selected because it is the beginning of the CRSS simulation and reflects the effects of initial reservoir conditions. Reservoir elevations in 1991 and 1992 were very low because of several years of below-normal

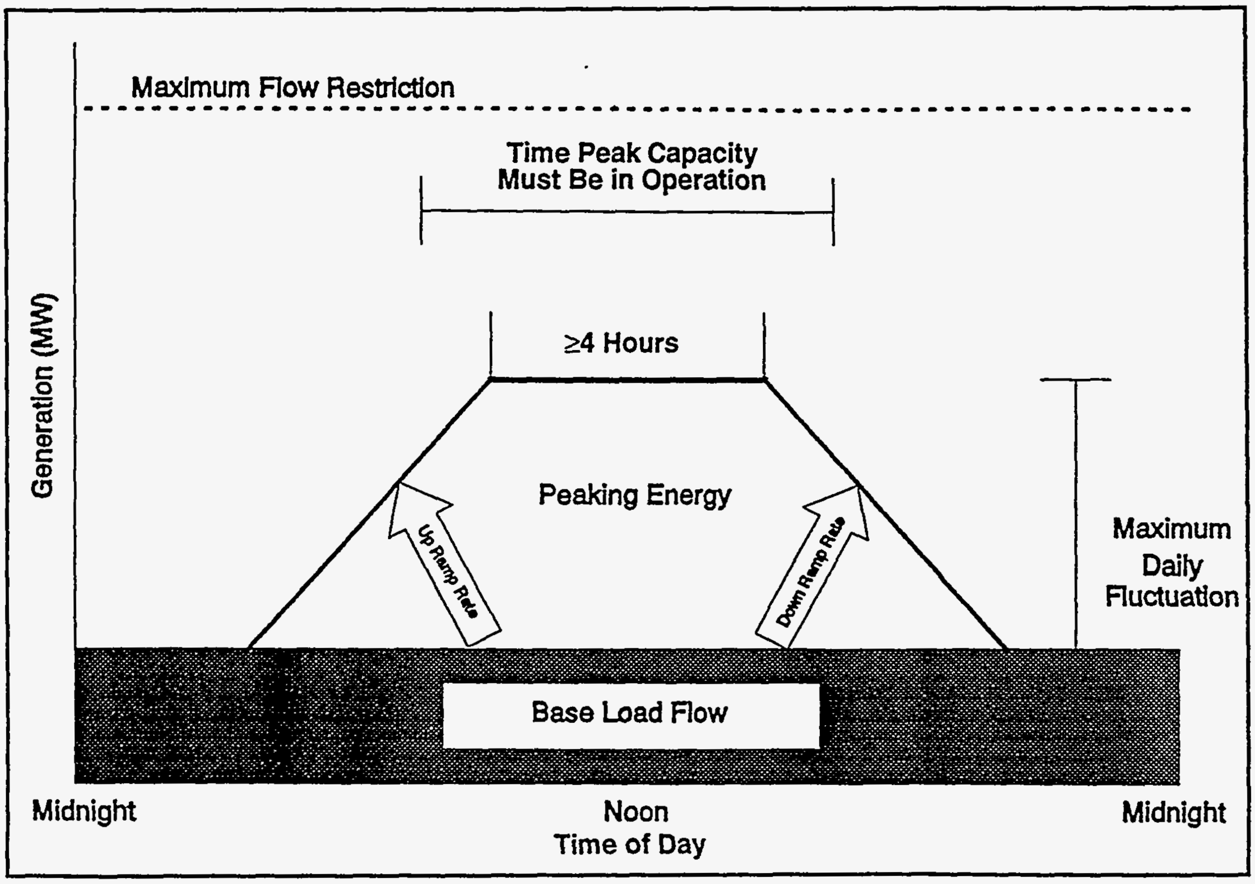

FIGURE 3 Geometric Approach for Estimating Operating Capacity

levels of precipitation in the Colorado River Basin. The CRSS forecasts that, on average, hydropower plant capacity and generation will gradually increase and peak in 1998. After 1998, hydropower plant capacity and generation are expected to decline slowly because of increases in water depletion; that is, more water will be diverted from the Colorado River Basin for nonpower uses such as industrial and municipal consumption. Estimates of operating capacity for the years between 1993, 1998, and 2010 were based on a straight line interpolation method.

4.4.2 Collbran and Rio Grande Hydropower Plants

Because the Collbran and Rio Grande projects are not included in CRSS, forecasts for these projects are based on historical data. Data for 1977-1991 were used for the Collbran Project, and data for 1942-1991 were used for the Rio Grande Project. Because the correlation between generation levels at these projects and CRSP is statistically insignificant, average monthly values for the Collbran and Rio Grande projects are added to the CRSS results to obtain capacity and energy forecasts for SLCA/IP hydropower plants. Average project generation values (Table 11) were used for all forecast years. Because these averages are based on historic data, future changes in these two projects are not reflected. Because of the effects of depletion, future generation levels are expected to be smaller than they were in the past. Therefore, average values from historical data are somewhat higher than what are expected to occur in the future. However, because the Rio Grande and Collbran projects constitute only a small fraction (about 3%) of the total SLCA/IP resources, errors that may occur because of this method are relatively small.

4.4.3 Average Monthly SLCA/IP Energy and Seasonal Capacity

Table 12 shows average monthly energy values for 1993 through 2007 as a function of hydropower plant operational scenario. For this analysis, it was assumed that monthly electricity generation and reservoir conditions only depend on the operational scenario; that is, commitment-level alternatives do not influence the volume of monthly water releases. Monthly water releases are also identical for the high- and medium-flexibility scenarios. Under these two scenarios, more water tends to be released in peak load months (i.e., January and July) than is released in low load months. However, the low-flexibility scenario differs from the other two scenarios, since more water is released in the spring and fall, while less water is released in the summer and winter. Because electricity prices are correlated with loads, the low-flexibility scenario tends to reduce the value of electricity produced by SLCA/IP hydropower plants. All three scenarios generate the same amounts of electricity per year. Operational scenarios affect monthly water release volumes, but total annual release volumes are not affected.

Table 13 shows projected winter and summer operating SLCA/IP capacity at the 90% exceedance probability level (i.e., hydropower plant capacity is lower than this level in only 1 in 10 years). This exceedance level is presented because it is what Western uses to

TABLE 11 Historical Generation Levels at the Rio Grande and Collbran Projects

Month	Historical Average Generation (MWh/month)	
	Collbran	Rio Grande
January	3,591	22
February	2,841	4,274
March	2,950	8,195
April	3,082	8,959
May	6,714	8,956
June	7,943	10,274
July	5,861	10,413
August	4,316	5,721
September	4,049	1,991
October	3,503	0
November	3,705	0
December	3,850	0

TABLE 12 Average Monthly SLCA/IP Energy Values by Operational Scenario, 1993-2007

Month	Average Generation by Operational Scenario (GWh/month)		
	High Flexibility	Medium Flexibility	Low Flexibility
January	600	600	519
February	483	483	539
March	501	501	549
April	524	524	555
May	549	549	565
June	584	584	567
July	671	671	568
August	574	574	521
September	458	458	508
October	459	459	496
November	472	472	485
December	470	470	478
Annual	6,346	6,346	6,346

TABLE 13 SLCA/IP Hydropower Capacity at the 90% Exceedance Level by Operational Scenario[a]

Operational Scenario	Winter (MW)	Summer (MW)
High flexibility	1,475	1,550
Medium flexibility	1,105	1,137
Low flexibility	522	613

[a] Based on CRSS model outputs and the geometric algorithm.

determine marketable firm capacity. The table displays average values during the 15-year LTF contract period. Historically, the capacity for the Collbran and Elephant Butte projects has been incorporated into the marketable resource mix. However, because those power plants are operated primarily for irrigation purposes and have somewhat unpredictable release patterns, for LTF power marketing, no capacity credit is assigned to these projects. Operating capacity in July represents summer, and January represents winter. These months represent critical peak load months. Operating capacity decreases as operational flexibility is reduced and is somewhat higher in the summer than it is in the winter.

5 HYDROPOWER AUGMENTATION

Because of the noninterruptible nature of LTF commitments, if Western is unable to supply sufficient capacity and/or energy from SLCA/IP hydropower plants, it must secure additional resources. Factors such as hydrologic variability, unscheduled outages, downed transmission lines, erratic acts of nature, and the imposition of stringent constraints on hydropower plant operations are unpredictable to some degree. These factors introduce uncertainties about the level of available electricity generation and capacity from SLCA/IP hydropower plants and Western's transmission capabilities. Because of these external influences, Western's resources are often highly variable over time. Therefore, Western is at risk of not meeting its contractual obligations when it offers firm capacity and energy to its customers. However, through its purchasing programs, Western can secure generating capacity and energy from neighboring electric utility companies. Historically, this capacity has come in the form of non-firm energy purchases during periods of low hydropower conditions. Current low hydropower conditions, compounded by interim flow restrictions at Glen Canyon Dam, have caused Western to enter into non-firm purchase agreements with the Rocky Mountain Generation Corporation and three other utility systems.

5.1 METHODOLOGY FOR ESTIMATING LONG-TERM FIRM PURCHASES

The following equation estimates the level of monthly LTF energy that Western must purchase to meet its firm obligations:

$$LTFEP_m = [(LTFES_m + PEU_m) \times (1.0 + TLF)] - HE_m \, , \tag{5.1}$$

$$\text{if } LTFEP_m < 0, \text{ then } LTFEP_m = 0,$$

where

$LTFEP_m$ = LTF energy purchases (GWh),

$LTFES_m$ = total LTF energy sales (GWh),

PEU_m = average monthly project use energy (GWh),

TLF = transmission loss factor (fraction),

HE_m = average monthly SLCA/IP hydropower energy (GWh), and

m = month of the year.

The following equation estimates seasonal LTF capacity that Western must purchase to meet its firm obligations:

$$LTFCP_s = [(LTFCS_s + PCU_s) \times (1.0 - DF) \times (1.0 + TLF)] + LC_s + SRR_s - HC_s, \quad (5.2)$$

$$\text{if } LTFCP_s < 0, \text{ then } LTFCP_s = 0,$$

where

$LTFCP_s$ = LTF capacity purchases (MW),

$LTFCS_s$ = total LTF capacity sales (i.e., the sum of all customers' load-patterned monthly capacity in the two representative months [MW]),

PCU_s = average monthly project use capacity (MW),

DF = diversity factor (fraction),

TLF = transmission loss factor (fraction),

LC_s = area load control responsibilities (MW),

SRR_s = spinning reserve requirements (MW),

HC_s = hydropower capacity at the 90% exceedance level (MW), and

s = season, where January represents winter, and July represents summer.

As shown in these equations, Western's LTF purchasing program is based on projected average hydropower conditions for energy and a 90% exceedance level for capacity. Because hydropower conditions are expected to change over time, energy and capacity averages are based on projected hydropower conditions over the 15-year LTF contract period. Western chose these levels, which are consistent with the post-1989 power marketing criteria. Capacity is not purchased by Western from a particular utility system, but is assumed to be purchased from an unspecified seller (i.e., a utility other than the 17 large systems modeled in this study, a cogenerator, independent power producer, etc.) at a market rate of $180/kW-yr. This rate is consistent with that assumed in the Glen Canyon Dam EIS. The LTF energy is priced on an hourly basis, as determined by the spot market model. This price represents the hourly marginal value of energy.

The LTF capacity and energy commitments for various marketing alternatives are discussed in Sections 4.2.1-4.2.3, and SLCA/LP hydropower resources for various operational scenarios are presented in Section 4.3.

5.2 SLCA/IP NON-FIRM SERVICES AND OBLIGATIONS

In addition to fulfilling LTF commitments, Western uses SLCA/IP capacity and energy resources for project use, Western Area Upper Colorado (WAUC) regulation control services, IPP spinning reserves requirements, and compensation for losses on transmission lines. More details on these obligations and services are described in Veselka et al. (1995). To estimate LTF purchase needs, the capacity and energy needed for each of these obligations and services must be taken into account. Except where noted, Western provides all of the above services under all commitment-level alternatives.

5.2.1 Project Use

The CRSP Act of 1956 authorized construction of certain related projects. Power requirements for the operation of lift pumps for gravity irrigation, salinity control, and other uses for these projects are called "project use" requirements and must be satisfied before any power is marketed by Western pursuant to its marketing programs.

During the formulation of marketing criteria and the development of projections for capacity and energy from the CRSP facilities, Reclamation estimates the schedule of development for each of the participating projects and the electrical demand for both project use and other priority use. Reclamation provided Western with a schedule on February 18, 1992. This schedule (Table 14) estimates system peak load and energy sales for these related projects through the year 2007. The maximum capacity reserved for project uses was 34.3 MW with 46.6 GWh of energy in the winter, and 180 MW with 334.8 GWh of energy in the summer. Monthly peak demands and energy were patterned after monthly historical project use profiles. Prior to interim flow restrictions, these amounts were less than 2% of the total SLCA/IP hydropower plant capacity and energy in the winter, with approximately 12% of the total capacity and energy in the summer.

5.2.2 Spinning Reserves and Load Control Responsibilities

The WSCC has established minimum operating reliability criteria that define the performance standards to be used by its members in operating the interconnected system. Capacity needed to fulfill primary and secondary spinning reserve requirements for WSCC standards are fulfilled through Western's participation in the Inland Power Pool (IPP). Although spinning reserve requirements vary over time, historically they account for approximately 45 to 65 MW. Western's requirements are based on numerous factors such as the size of the single largest hazard and WAUC's share of the load. Estimates of Western's spinning reserve requirements (Table 15) were determined by the IPP spreadsheet model. For long-range planning, conservative estimates (i.e., relatively high) of spinning reserves were used. Peak and total loads input into the IPP spreadsheet calculation are based on Western's LTF contracts, as specified by a commitment-level alternative. Capacity at Glen Canyon was used as the single largest hazard and varied as a function of operational scenario.

TABLE 14 Forecasts of Energy Required for Annual Project Use

	System Peak Load (MW)		Energy Sales (GWh)	
Year	Winter[a]	Summer[b]	Winter[a]	Summer[b]
1993	8.3	59.2	11.7	89.0
1994	8.3	59.2	11.7	89.0
1995	8.3	59.2	11.7	90.0
1996	8.3	86.6	11.7	144.5
1997	9.7	112.6	19.2	218.4
1998	29.7	130.6	43.5	236.4
1999	29.7	147.6	43.5	265.6
2000	30.4	160.4	44.6	291.6
2001	30.4	170.2	46.1	319.2
2002-2007	34.3	180.0	46.6	334.8
Annual average	24.6	137.7	34.9	250.16

[a] Winter peak occurs in October.

[b] Summer peak occurs in June.

The capacity required for WAUC load control services to respond to instantaneous changes in frequency has historically been about 50 to 56 MW (56 MW was used in this analysis). In addition to frequency responses, unscheduled internal load changes for other utilities can require generation changes up to 150 MW per hour. Although internal load control assistance is occasionally requested during the morning when system loads increase rapidly, Western is not obligated to provide this service. Because on-peak internal load assistance does not usually occur, and it is at Western's discretion to provide this assistance, it is not necessary to reserve capacity for this service. Under the low operational flexibility scenario, Western will not be able to supply these services because there is no operational flexibility at SLCA/IP resources to respond to internal load changes and to respond to random outages.

5.2.3 Transmission Losses and Diversity Factors

Western has agreed to deliver energy to specified connection points via its transmission lines and compensates for losses that occur in the transmission process. On the basis of data found in a U.S. Department of Energy (DOE) report (DOE 1985), approximately 7% of the electricity generated by SLCA/IP hydropower plants is lost through transmission. Historically, losses consume up to 292 and 155 MW of capacity in the summer and winter, respectively. They also can consume up to 340 and 47 GWh of electricity in the summer and winter, respectively.

TABLE 15 IPP Spinning Reserve Requirements

Scenario/ Alternative	Winter: Spinning Reserves[a] (MW)	Winter: Area Load Control (MW)	Summer: Spinning Reserves[a] (MW)	Summer: Area Load Control (MW)
High Flexibility				
No Action	64	56	64	56
2	63	56	73	56
4	28	56	28	56
5	32	56	32	56
Medium Flexibility				
No Action	64	56	65	56
2	72	56	73	56
4	28	28	29	56
5	32	32	32	56
Low Flexibility				
No Action	0	0	0	0
2	0	0	0	0
4	0	0	0	0
5	0	0	0	0

[a] Based on relatively low estimates of monthly peak loads and total demand for other IPP members resulting in relatively high estimates of spinning reserve requirements.

Historically, Western has not accounted for losses in its capacity marketing strategy because its customers' peak energy demands are not coincidental; that is, peak demands among Western's customers do not occur simultaneously. The difference between the coincidental peak and noncoincidental peak is also approximately 7%. Diversity in loads among customers and losses in capacity due to transmission offset each other. For this study, it is assumed that no additional capacity is required to offset losses.

5.3 LONG-TERM FIRM PURCHASING LEVELS

Table 16 shows LTF capacity and energy purchases as a function of the LTF commitment-level alternative and the hydropower operational scenario. The No Action Alternative with high operational flexibility does not require LTF capacity purchases. However, 237 GWh of additional LTF energy is needed annually. Although SLCA/IP LTF energy sales for the No Action Alternative were originally based on annual average

TABLE 16 Western Long-Term Firm Capacity and Energy Purchases as a Function of Commitment-Level Alternative and Operational Scenario

	Winter		Summer	
Scenario/ Alternative	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)
High Flexibility				
No Action	0.0	59.3	0.0	177.7
2	68.6	0.0	166.8	0.0
4	0.0	0.0	0.0	0.0
5	0.0	104.5	0.0	55.1
Medium Flexibility				
No Action	285.0	59.3	396.9	177.6
2	448.0	0.0	579.7	0.0
4	0.0	0.0	0.0	0.0
5	0.0	104.5	0.0	55.1
Low Flexibility[a]				
No Action	747.1	48.4	801.0	303.5
2	902.6	0.0	975.3	0.0
4	18.4	0.0	77.1	0.0
5	150.3	43.8	205.9	41.0

[a] Capacity estimates assume that Western would not be able to have area load control responsibilities and that IPP spinning reserves would have to be purchased from another utility.

hydropower conditions, the CRSS energy forecast has been revised downward since the time when the No Action Alternative was formulated. Revisions are based on current low hydropower conditions and additional historical hydrological data recently incorporated into CRSS. The LTF energy purchases are also based on monthly hydrology, whereas the No Action Alternative was (at the time of its inception) based on seasonal hydrology. Therefore, a portion of the LTF energy purchases is attributed to differences between the monthly distribution of energy releases from SLCA/IP hydropower plants and the monthly distribution of LTF energy sales as computed by the LTF load patterning method.

The LTF capacity purchase requirements increase as hydropower plant operational flexibility declines. For example, under the No Action Alternative, capacity purchases are zero and increase to more than 700 MW under the low-flexibility scenario because operating capacity is highly influenced by the operational scenario. On the other hand, total annual energy releases are not affected by operational restrictions, and LTF energy purchases are primarily a function of commitment-level alternative. For a specific commitment-level alternative, LTF energy purchases are identical for the high- and medium-flexibility scenarios but differ for the low-flexibility scenario. This difference is attributed to the shifting of water releases among months under the low-flexibility scenario (Table 12).

Relative to SLCA/IP generation and LTF energy commitments, LTF purchases are relatively small. Average annual LTF energy commitments can exceed 5,700 GWh, while LTF energy purchases are about 300 GWh (about 5% of LTF energy sales). However, LTF capacity purchases can make up a significant portion of Western's LTF capacity commitments. In the most extreme case, LTF capacity purchases serve 975 MW of a 1,450 MW LTF capacity commitment (i.e., 67% of LTF capacity sales).

Using the simple method for determining LTF purchases (Section 5.1) can result in an apparent mismatch between capacity and energy purchases. For example, under Alternative 2 (i.e., high capacity, low energy) with low operational flexibility, LTF capacity purchases are more than 900 MW without any associated LTF energy purchases. However, as demonstrated in Section 6, Western is required to purchase large amounts of costly on-peak energy under this commitment-level alternative and operational scenario. The cost of these purchases is set to the non-firm market price on an hour-by-hour basis, as determined by the spot market and hydro LP models. Although the market price of this energy on the LTF market may differ from the non-firm market price, the non-firm market price provides an accurate measure of the economic cost of energy. As explained in detail in Section 10, for this analysis, the spot market price is equal to the marginal cost of production, with consideration of transmission limitations and other physical and institutional constraints. A detailed analysis of optimal LTF purchase programs for each commitment-level alternative and operational scenario combination would require extensive time and resources, and would not alter the conclusions of the analysis. Recently, Western received several bids for firm energy that would be purchased over the next five years. Prices for this energy are similar to current non-firm market prices and the prices projected by ANL's spot market and hydro models.

In some situations, the total amount of energy is sufficient to meet LTF commitments, but Western must purchase energy on-peak because of operational restrictions. Costs for the capacity shortfall (i.e., the inability to use capacity to meet demand because of operational restrictions) are based on an assumed market value for capacity and the level of capacity purchased, as determined by Equation 5.1. Costs for energy purchases and revenues from "forced" spot market sales are based on hourly spot market prices. Detailed examples of energy purchase and sales are illustrated in Section 6.

6 SHORT-TERM SALES AND PURCHASES

Western offers both non-firm (interruptible) energy and STF services. Non-firm energy is sold to both preference and nonpreference customers on the spot market. The STF energy and capacity contracts are offered first to preference customers. Remaining resources are then offered to nonpreference customers. This section discusses both commitment-level alternatives and operational scenarios affecting these services.

Western offers two types of short-term non-firm electric energy services: fuel replacement energy service and economy energy service. While these non-firm, energy-only services are similar in many respects, they differ from each other in the rates Western charges a customer. For this analysis, it was assumed that all non-firm energy would be sold as economy energy on the non-firm market.

Western's spot market activities and the level of STF energy sales depend in part on hydropower conditions. In general, the higher the amount of energy available for generation, the greater the level of STF and non-firm market sales. It was, therefore, necessary to model various hydropower conditions to adequately assess the effects of commitment-level alternatives and operational scenarios on short-term sales and purchases.

6.1 SLCA/IP HYDROPOWER VARIABILITY

Non-firm energy and STF sales were examined under three different hydropower conditions: wet, normal, and dry. An average cost weighted by hydropower probability is used to compute utility impacts. As described in Section 4.4, CRSS projects 85 future hydropower plant capacity and energy outcomes on the basis of initial reservoir conditions, historical hydrological flow data, and anticipated water depletion. Projections are made for each CRSP and Seedskedee hydropower plant on a monthly basis. Ideally, all 85 projected outcomes could be analyzed in detail. However, impacts of commitment-level alternatives and operational scenarios can be adequately assessed by examining representative wet, normal, and dry hydropower conditions for combined SLCA/IP resources. These conditions were selected on the basis of a clustering technique, which allowed capacity and energy projections to be examined simultaneously.

Selecting representative conditions for each dam begins with estimating the maximum capacity by trace and projection month. Monthly scatter plots of capacity and energy for SLCA/IP facilities are then constructed. Each point on the scatter plot represents the total amount of SLCA/IP capacity and energy projected by CRSS for a particular trace. Scatter plots (Figure 4) are based on normalized values of capacity and energy. A normalized value of 1.0 represents the projected outcome that has the highest value; this value serves as a benchmark for all other outcomes. Three clusters of points that result in the lowest root-mean-square error represent wet, normal, and dry hydropower conditions. The root-mean-square error is computed by summing the squared distance between a fixed point and a

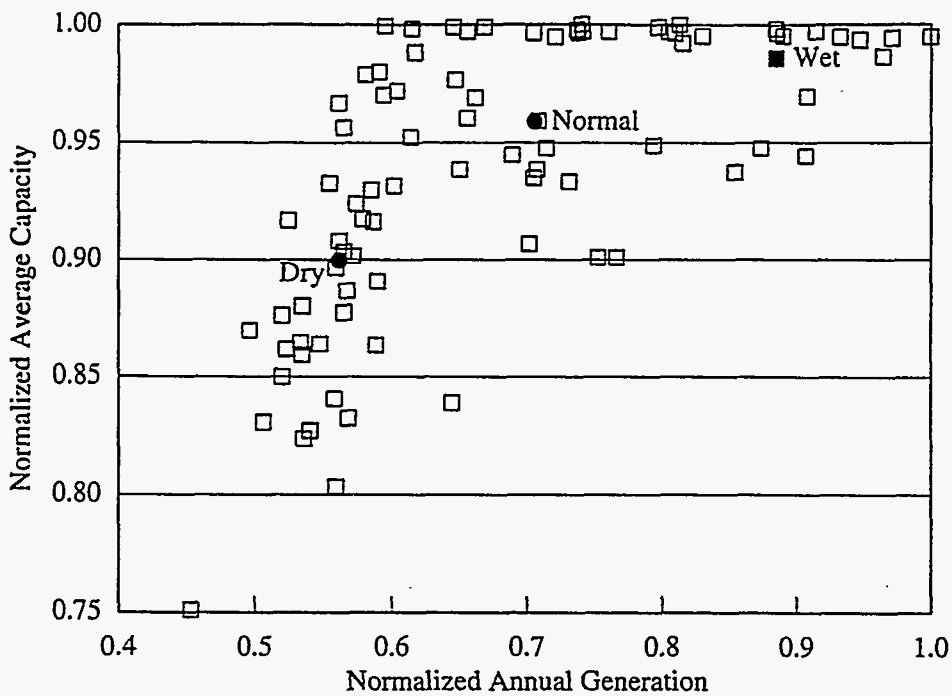

FIGURE 4 Scatter Diagram Depicting the Clustering Method for Determining Representative Wet, Normal, and Dry Hydropower Conditions

subset or cluster of projected outcomes. The number of projected outcomes in each cluster is used to estimate the probability of occurrence of a hydropower condition.

After clusters of observations have been determined, SLCA/IP hydropower plant capacity and energy for all outcomes in a cluster are decomposed into capacity and energy contributions for each individual dam. Average capacity and energy values are then computed for each cluster and for each dam. Cluster averages represent a dam under the three different hydropower conditions. This clustering technique was used to determine representative hydropower conditions for January, April, July, and October for 1992, 1998, and 2010. Other months in the study were estimated through interpolation by using average monthly CRSS energy projections as control totals. Because monthly capacity and energy projections are a function of operational scenario, separate values were determined for the high-, medium-, and low-flexibility scenarios.

The SLCA/IP hydropower plant energy projections for the high-flexibility scenario for 1993 and 1998 are shown in Figures 5 and 6, respectively. A comparison of the two figures shows a similar monthly water release pattern. However, energy releases are lower in 1993 than they are in 1998. A greater difference between dry and wet conditions is also displayed in 1998. Much of this increase in hydropower variability is due to uncertainty about the future as the duration increases between initial reservoir conditions and the forecast year. Estimates for each month should be viewed as independent values. For example, a representative dry year is likely composed of some months that have normal energy releases and perhaps above-normal releases.

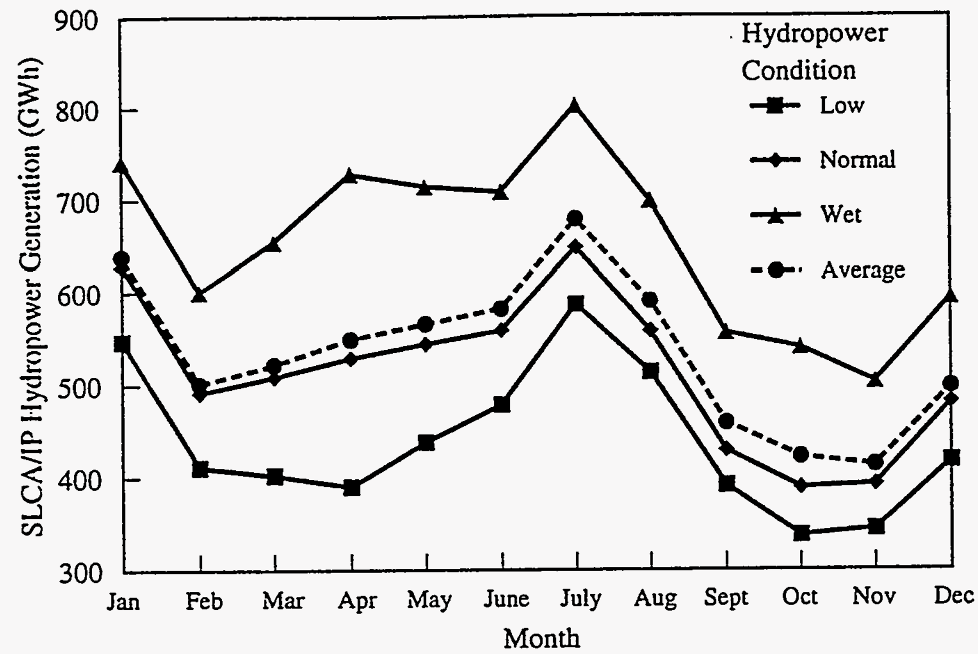

FIGURE 5 Projections of SLCA/IP Hydropower Plant Generation for the High-Flexibility Scenario for 1993

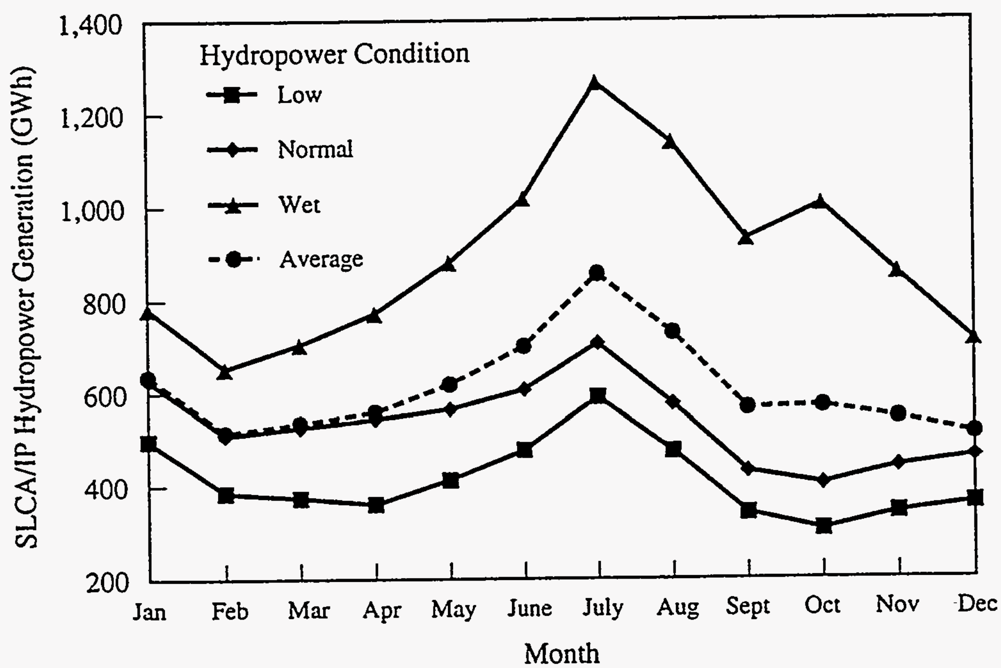

FIGURE 6 Projections of SLCA/IP Hydropower Plant Generation for the High-Flexibility Scenario for 1998

Figures 7 and 8 show changes in SLCA/IP hydropower plant operating capacity and energy as a function of operational flexibility and hydropower conditions for January and July, respectively. Capacity decreases as operational flexibility is reduced and hydropower conditions become drier. The operating capacity is also more sensitive to hydropower conditions when hydropower operations are more constrained. Whereas the operating capacity under the high-flexibility scenario depends on the hydrologic head, the operating capacity under the low-flexibility scenario depends on both the hydrologic head and the monthly water release volume (i.e., capacity = monthly energy/hours in a month).

6.2 SHORT-TERM FIRM SALES

Short-term firm sales are offered when projected supply resources significantly exceed LTF and project use commitments. The STF capacity and energy commitments are contractual power agreements that are either seasonal or monthly. The rate charged for STF service is the same rate charged for LTF service. Three types of STF electric service have been offered in the past: surplus energy, excess capacity, and a combination of both.

Surplus energy is additional hydropower generation assumed to be available because of projected increased water releases by Reclamation within a specified time. Because of this increased water release and associated increased hydropower plant generation, Western has extended energy-only offers to existing LTF customers. The increased energy commitment, when accepted by the customer, results in an increase in seasonal load factors associated with the customer's seasonal CROD under existing LTF electric service contracts. The STF capacity sales without additional energy decrease a customer's load factor. They also increase the customer's minimum schedule requirement and, therefore, decrease the energy available for discretionary use.

6.2.1 Methodology

A general rule for determining STF energy sales was determined by analyzing historical data contained in Western's Annual Operating Plan (AOP). A relationship between projected excess energy for the upcoming year and STF energy offered to customers was approximated by using a regression analysis (Figure 9). Historical monthly STF energy offered to customers was estimated by subtracting monthly LTF energy estimates from AOP monthly firm demand estimates. The AOP firm demand data contain an aggregate value for both LTF and STF energy sales. Excess energy projections were approximated by subtracting monthly LTF demands from monthly SLCA/IP hydropower plant generation. Results from the regression analysis indicate that excess energy (i.e., energy that exceeds approximately 100 GWh) is sold as STF.

Unlike STF energy, a general relationship between excess capacity and STF sales could not be readily determined. By examining the historical STF capacity offers, it also became apparent that the excess capacity was not always sold to preference customers.

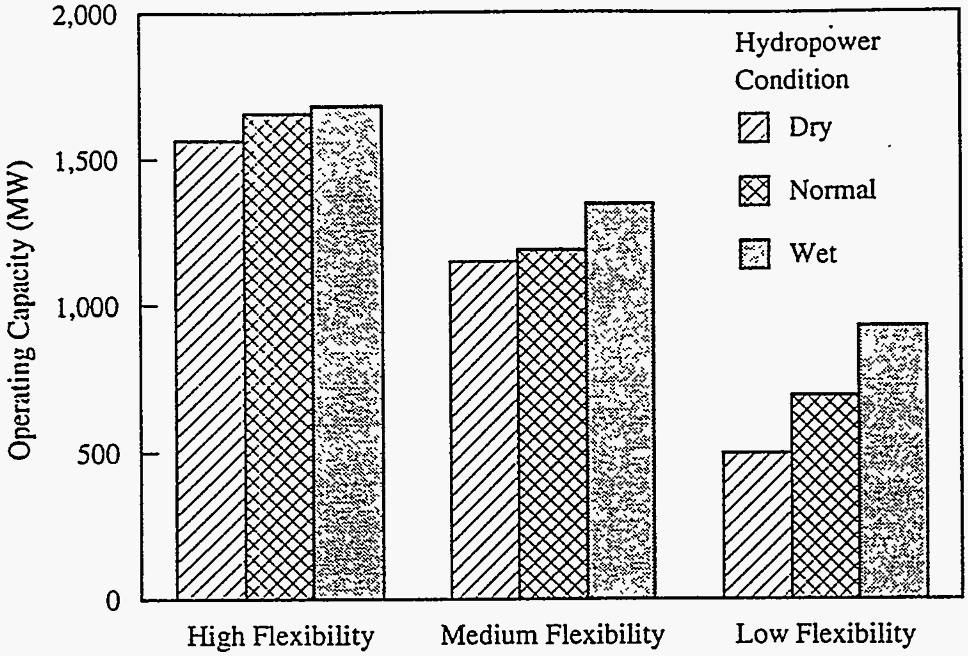

FIGURE 7 SLCA/IP Hydropower Plant Capacity for the Operational Scenarios for January 1998

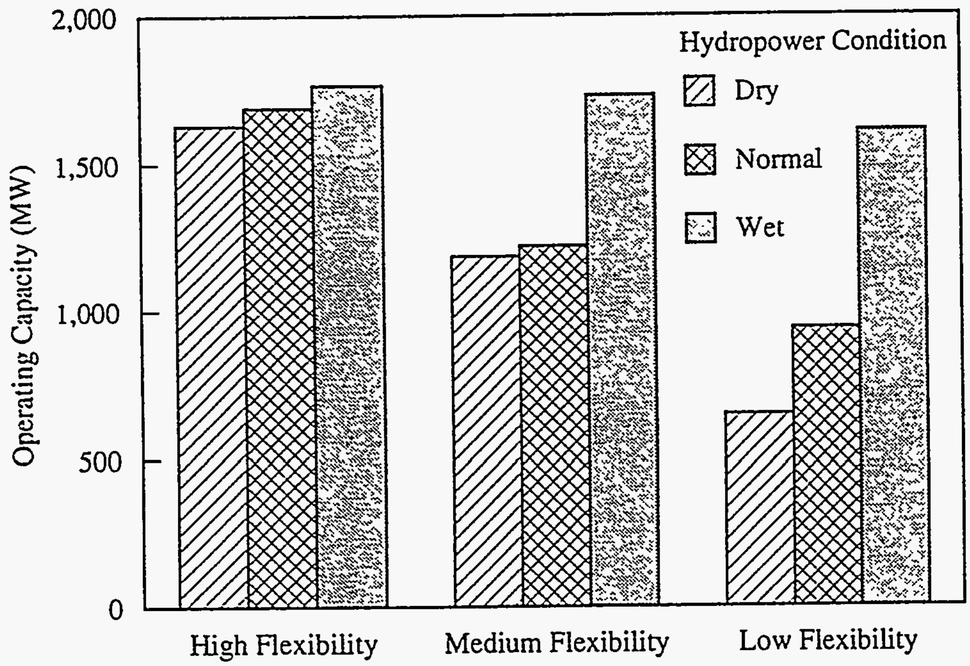

FIGURE 8 SLCA/IP Hydropower Plant Capacity for the Operational Scenarios for July 1998

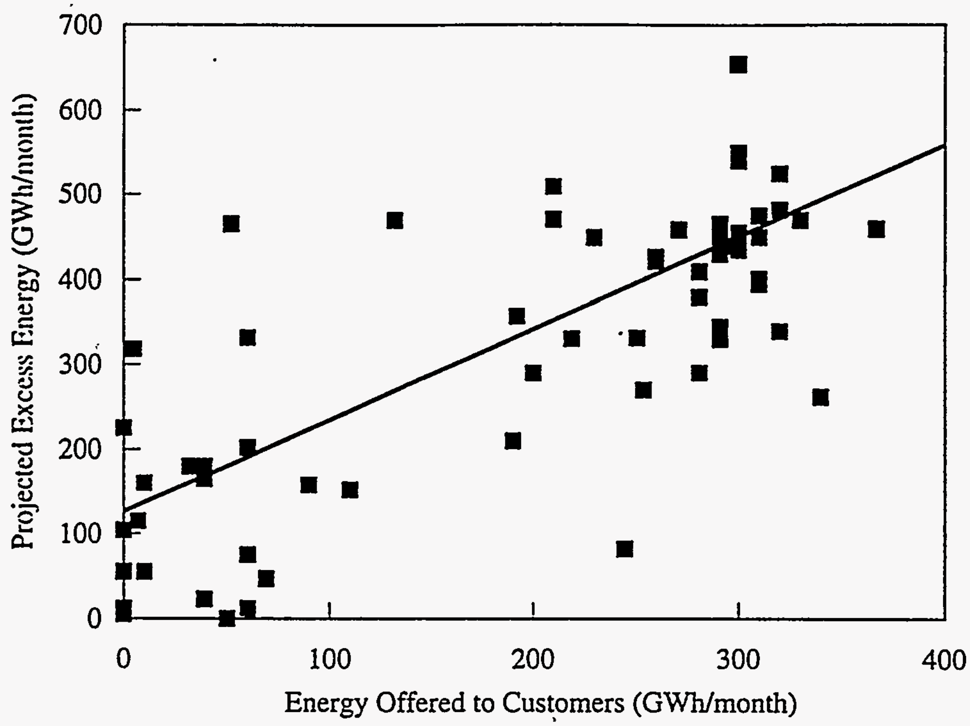

FIGURE 9 Historical Relationship between STF Energy Offered to SLCA Customers and Projected Excess CRSP Energy

Because of these complexities, it was assumed that STF capacity would not be offered to customers. However, SLCA/IP capacity would be available to sell energy on the non-firm market during peak demand hours. Because STF capacity was not sold with STF energy, STF energy sales were constrained by a 100% load factor.

Given the lack of historical experience with different combinations of marketing strategies and hydropower operations, it is not possible to establish general rules for both LTF purchases and STF sales that would be used in the future. However, an attempt was made to establish a set of general rules based on past operations.

6.2.2 Short-Term Firm Sales Results

Western's STF sales depend on hydropower conditions and the commitment-level alternative. As shown in Table 17, STF sales tend to be higher when LTF sales are lower (e.g., Alternatives 2 and 4). Table 17 is based on average values over the 15-year contract. Because of present-day hydropower conditions, STF sales tend to be lower than the average sales in 1993. Short-term firm sales are projected to increase until approximately 1998, and then slowly decline through 2007. This decline is due to the effects of depletion.

Short-term firm sales increase with higher hydropower energy releases (i.e., under wet conditions). One exception to these general trends occurs under Alternative 5. Because

TABLE 17 Average Annual Short-Term Firm Energy Sales by Commitment-Level Alternative, Hydropower Condition, and Operational Scenario

	Operational Scenario		
Commitment-Level Alternative[a]/ Hydropower Condition	High Flexibility (GWh)	Medium Flexibility (GWh)	Low Flexibility (GWh)
No Action Alternative			
Dry	0	0	0
Normal	2	24	36
Wet	2,018	2,346	2,347
Weighted average	357	347	397
Alternative 2			
Dry	225	226	177
Normal	1,071	1,350	1,264
Wet	3,973	4,320	4,245
Weighted average	1,226	1,247	1,239
Alternative 4			
Dry	221	223	169
Normal	769	992	840
Wet	1,067	1,067	1,067
Weighted average	593	612	560
Alternative 5			
Dry	0	0	0
Normal	0	0	0
Wet	0	0	0
Weighted average	0	0	0

[a] The LTF energy is 5,702 GWh for the No Action Alternative, 3,300 GWh for Alternatives 2 and 3, and 5,475 GWh for Alternative 5.

under this alternative the LTF load factor is 100%, no additional firm energy can be sold without additional STF capacity. As stated above for this study, all STF capacity sales are set to zero in all situations. The STF sales under wet conditions are also significantly higher under Alternative 2 than under Alternative 4. This condition occurs because under Alternative 4, STF sales are limited by the 100% load factor; that is, under wet conditions the SLCA/IP load factor based on LTF plus STF energy is almost always 100%.

For this study, monthly STF sales were assigned to each customer on the basis of LTF energy allocation percentages. Short-term firm sales do not significantly change as a function of operational scenario. For a given commitment-level alternative, the weighted average STF energy sales are approximately equal under all operational scenarios. This fact occurs because STF energy sales depend on the amount of excess SLCA/IP hydropower energy above LTF energy commitments. Slight differences occur because of the method used to select representative wet, normal, and dry hydropower conditions.

6.3 PROJECTED NON-FIRM ENERGY SALES AND PURCHASES

Western's participation in the non-firm market depends on its firm sales obligations, SLCA/IP hydropower operational flexibility, hydropower conditions, and spot market prices. When Western has more SLCA/IP energy than its LTF commitments demand, the excess energy that is not sold as STF energy is sold on the non-firm market. Western also uses the spot market to "shift" water releases from off- to on-peak periods. That is, Western purchases energy off-peak to serve its firm loads and sells the "stored" energy on the non-firm market during on-peak periods. Western engages in this activity when on-peak sales revenues are approximately 3 mill/kWh higher than off-peak purchases. The 3 mill/kWh value is based on information found in monthly operating guidelines used by dispatchers at the Montrose office. The timing of purchases and non-firm sales depends on Western's hourly loads and the level of flexibility that Western has to operate SLCA/IP hydropower plants.

From a utility system viewpoint, the main objective is to buy energy at a low price and sell it on the non-firm market when its value is high. However, under certain combinations of power commitment-level and operational scenario, the opposite occurs. For example, under the No Action Alternative with low operational flexibility, Western must either sell or "spill" water during off-peak hours when generation is higher than firm demand and purchase energy during on-peak hours when generation is less than firm demand. In this section, SLCA/IP hydropower plant operations are illustrated under various spot market conditions.

6.3.1 SLCA/IP Hydropower Dispatch Module

The hydropower dispatch module (called the Hydro LP [linear program] module) simulates Western's SLCA/IP hydropower plant operations to serve firm and project use loads. It also estimates Western's hourly purchases and non-firm sales of energy. Purchases include LTF, STF, and non-firm energy. Purchase and sales transactions presented here are only for hydropower shifting and to meet firm loads. The spot market network module (Section 10) simulates Western's sales-for-resale transactions. Energy purchases allow Western to serve its loads and non-firm energy sales to increase its revenues. Model estimates are based on the assumption that Western maximizes the value of its supply-side resources through cost minimization, thereby minimizing the rate Western charges its LTF customers. These activities are based on market prices as determined by the Spot Market Module and Western's ability to shift SLCA/IP power plant electricity generation from off- to on-peak periods. Hourly purchases and sales depend on the water available for generation, on Western's hourly firm commitments, and on flow restrictions at each of the SLCA/IP hydropower plants. Operational restrictions incorporated into the Hydro LP module include (1) minimum and maximum flow restrictions, (2) hourly and daily ramp rate restrictions, and

(3) minimum and maximum elevation levels at the Crystal Reservoir. The Hydro LP module also includes a minimum transaction margin that is required for off- to on-peak hydropower shifting and accounts for area load control services and IPP spinning reserve requirements.

Maximum output levels are based on maximum flow restrictions and representative water-to-power conversion factors. The maximum output is also adjusted for IPP spinning reserves and area load control services. Minimum output levels are based on minimum flow restrictions and representative water-to-power conversion factors. The minimum output is also adjusted for area load control services.

The Hydro LP module runs on a weekly basis to estimate hydropower operations for each hour in a week. Because of ramp rate restrictions and monthly mandated water releases, each hour of operation in the simulated week depends on all other hours in the simulation period. For this analysis, each week simulated begins at midnight on a Thursday and ends at midnight the following Wednesday. These beginning and ending times were chosen to minimize simulation boundary problems (i.e., beginning and end effects) associated with the interaction of weekend firm loads and hourly market prices with daily ramp rate restrictions.

Because the Hydro LP module is simulated for one week each month, SLCA/IP power plant generation projections for a specific condition and time period were scaled down proportional to the number of days in a month. Likewise, monthly results were estimated by scaling up aggregated weekly results.

The Hydro LP module was run for 1993, 1998, and 2008. The year 1993 is the first year of the study, and 2008 represents the end of Western's LTF contract. The year 1998 was also run because it represents the year that has the highest expected hydropower conditions. Estimates for all other years were interpolated. The Hydro LP module was run for all 36 combinations of the four commitment-level alternatives, three hydropower operational scenarios, and three hydropower conditions.

6.3.1.1 Western's Hourly Loads

For each hour of every day of the year, Western has an obligation to supply its firm customers with electricity, as specified in its LTF and STF contracts. Western also has an obligation to provide energy and capacity for project use. Currently, Western's contracts specify the amount of electricity that each firm customer will receive on a monthly basis and stipulates limitations in terms of maximum and minimum hourly energy deliveries. Within these limits, Western's customers determine the hourly distribution of deliveries within each month. A customer either directly schedules hourly energy deliveries with one of three Western dispatch centers or uses another designated utility to schedule its deliveries.

Western's total firm load is the summation of all the schedulers' hourly demands. The peak-load reduction algorithm was used to project an individual customer's hourly firm demand requirements. The algorithm simulates hourly purchases from Western such that the purchases minimize the maximum load on a utility's supply-side resources (Section 8.3.1.3). The level of demand reduction in each hour depends on the commitment-level alternative and STF sales. Because STF energy sales are scenario dependent, hourly firm demand estimates are approximated at the utility level for all 36 combinations of commitment-level alternative, operational scenario, and hydropower condition. Loads from the 12 large Western customers are summed on an hour-by-hour basis.

Although Western serves many smaller systems, the 12 large customers account for more than 85% of Western's LTF energy demands. Hourly demands from smaller systems and from project use are estimated by applying a monthly scaling factor to the total hourly loads of the 12 large systems. The scaling factor is the ratio of total monthly demand (firm demand + project use) relative to the firm demand from the 12 large customers. After Western's total hourly demands are computed, demands are increased by 7% to account for transmission and system losses.

6.3.1.2 Representation of Hydropower Plant Operations

Each SLCA/IP hydropower plant has a unique set of characteristics such as generating capacity, water-to-energy conversion factor, and storage capacity. Some hydropower plants are also on automatic generation control (AGC) and can be regulated instantaneously regulate electricity production, while other hydropower plants are operated mainly for irrigation purposes and are not on AGC. Because of these differences and the relative importance of each hydropower plant for estimating the impacts of commitment-level alternatives and operational scenarios, the characteristics of each power plant and the method used to represent its operation differ for each power plant.

The four larger power plants, all of which are on AGC, were simulated in detail. These hydropower plants include Glen Canyon, Flaming Gorge, Blue Mesa, and Morrow Point. These facilities account for approximately 95% of SLCA/IP's hydropower plant capacity and energy resources. For each of these larger power plants, an up-ramp rate, down-ramp rate, minimum flow rate, and maximum flow rate restriction were specified for each hour of the day. A daily ramp rate was also specified, where applicable.

The Hydro LP module assumes that the hourly operation of Morrow Point depends on water releases from Crystal and on side flows between these two hydropower plants. The reservoir elevation at Crystal must be within the narrow range dictated by Reclamation. Because of the close proximity of Morrow Point to Crystal and the characteristics of the Gunnison River channel between the two reservoirs, hourly releases at Morrow Point must be closely monitored to ensure that reservoir elevation constraints at Crystal are not violated. The Hydro LP module uses an area/capacity table (provided by Reclamation) for the Crystal Reservoir to estimate the change in elevation level per acre-foot of in-flow and out-flow. In-flows to Crystal include water releases from Morrow Point and from side flows. It was assumed that all of the water released from Morrow Point immediately flows into Crystal Reservoir. Side flows are calculated from CRSS module output data and estimated by a water balance equation such that monthly side flows equal monthly water releases at Crystal minus monthly water releases at Morrow Point. Side flows are assumed to be constant for all hours in the simulated week. It is also assumed that water releases from Crystal are constant.

Other SLCA/IP hydropower plants are smaller in terms of generating capacity and include Crystal, Fontenelle, Elephant Butte, Upper Molina, and Lower Molina. In aggregate, these facilities account for the remaining 5% of SLCA/IP hydropower plant capacity and energy. Although dispatchers can operate these plants with limited flexibility, historically they were operated at a constant output level. Therefore, the Hydro LP module assumes that each of the five smaller hydropower plants operates at a constant output level for all hours in a month. Hourly generation values assigned to Crystal and Fontenelle are based on monthly results produced by the CRSS model. That is, generation in each hour is set equal to the project's monthly generation, divided by the number of hours in the month. The method described in Section 6.1 was used to determine representative monthly capacity and energy values under wet, normal, and dry hydropower conditions for Crystal and Fontenelle, along with the four larger power plants.

Hourly generation levels assigned to the Rio Grande and Collbran (i.e., Upper and Lower Molina) projects are based on historical monthly releases (Section 4.4.2). Average energy values shown in Table 11 for Rio Grande and Collbran are used for all 36 situations simulated.

6.3.1.3 Hydro LP Module Formulation

The purpose of the Hydro LP model is to minimize Western's net operating costs. As shown below, Western's net costs are comprised of hourly energy purchases, supply source energy costs, and revenues from hourly non-fiirm energy sales:

$$\text{minimize} \sum_{i,j} [(KP_j + m)\, PURCH_j - KS_j\, SALES_j] + \sum_i C_i\, G_i\ , \tag{6.1}$$

where

i = Western's supply source (i.e., SLCA/IP hydropower plants), for $i = 1, I$;

j = hour of the day, for $j = 1, J$;

KP_j = hourly purchase price (mill/kWh), for $j = 1, J$;

m = transaction margin for off-peak to on-peak hydropower shifting (mill/kWh);

$PURCH_j$ = purchases, including LTF, STF, and spot market (MWh), for $j = 1, J$;

KS_j = hourly non-firm market sale price (mill/kWh), for j = 1, J;

$SALES_j$ = non-firm market sales (MWh), for j =1, J;

C_i = cost of generation at hydropower plant i (mill/kWh), for i = 1, I;

G_i = total generation at hydropower plant i during the simulated period (MWh), for i = 1, I;

J = total hours in the study period; and

I = total number of hydropower plants.

Minimizing net costs is subject to several hydropower plant operational constraints. Some constraints are physical limitations; others are institutional. Constraints in the Hydro LP module include the following (terms are defined after bulleted list):

- Western's total firm demand and project use demand are satisfied with energy generation from SLCA/IP power plant resources and purchases and non-firm sales:

$$PURCH_j - SALES_j + \sum_i G_{i,j} = d_j \text{ for all j.} \tag{6.2}$$

- Each hydropower plant has a total monthly energy generation estimated by CRSS:

$$G_i = tot_i \text{ for all i.} \tag{6.3}$$

- The sum of hourly energy from each hydropower plant must equal the monthly electricity generation (because each month is represented by a week's simulation period, CRSS generation values were scaled down proportionately):

$$\sum_j G_{i,j} - G_i = 0 \text{ for all i.} \tag{6.4}$$

- Each hydropower plant has a maximum hourly output that can vary by the time of the day:

$$G_{i,j} <= max_{i,j} \text{ for all i, j.} \tag{6.5}$$

- Each hydropower plant has a minimum hourly output that can vary by the time of the day:

$$G_{i,j} >= \min_{i,j} \text{ for all i, j.} \tag{6.6}$$

- Each hydropower plant has an hourly energy up-ramp rate restriction:

$$G_{i,j+1} - G_{i,j} <= HUPRMP_i \text{ for all i, j.} \tag{6.7}$$

- Each hydropower plant has an hourly down-ramp rate restriction:

$$G_{i,j} - G_{i,j+1} <= HDNRMP_i \text{ for all i, j.} \tag{6.8}$$

- Each hydropower plant has a daily up-ramp rate restriction:

$$\begin{gathered} G_{i,j+1} - G_{i,1} <= DUPRMP_i \text{ for all J} - 1\text{, and all i,} \\ G_{i,j+2} - G_{i,2} <= DUPRMP_i \text{ for all J} - 2\text{, and all i,} \\ G_{i,j+3} - G_{i,3} <= DUPRMP_i \text{ for all J} - 3\text{, and all i, and} \\ \vdots \\ G_{i,j+J-1} - G_{i,J-1} <= DUPRMP_i \text{ for j} = 1\text{, and all i.} \end{gathered} \tag{6.9}$$

- Each hydropower plant has a daily down-ramp rate restriction:

$$\begin{gathered} G_{i,1} - G_{i,j+1} <= DDNRMP_i \text{ for all J} - 1\text{, and all i,} \\ G_{i,2} - G_{i,j+2} <= DDNRMP_i \text{ for all J} - 2\text{, and all i,} \\ G_{i,3} - G_{i,j+3} <= DDNRMP_i \text{ for all J} - 3\text{, and all i, and} \\ \vdots \\ G_{i,J-1} - G_{i,j+J-1} <= DDNRMP_i \text{ for j} = 1\text{, and all i.} \end{gathered} \tag{6.10}$$

- At each hydropower plant, the generation difference between the first and last hour of operation must be less than the maximum hourly up-ramp restriction:

$$G_{i,1} - G_{i,J} <= HUPRMP_i \text{ for all i.} \tag{6.11}$$

- The generation difference between the last and the first hour of operation at each hydropower plant must be less than the maximum hourly down-ramp restriction:

$$G_{i,J} - G_{i,1} <= DNPRMP_i \text{ for all i.} \tag{6.12}$$

- The elevation at the Crystal Reservoir in each hour cannot be lower than a minimum level:

$$ELEV_j >= MINEL \text{ for all j.} \tag{6.13}$$

- The elevation at the Crystal Reservoir in each hour cannot be higher than a maximum level:

$$ELEV_j <= MAXEL \text{ for all j.} \tag{6.14}$$

- The elevation at the Crystal Reservoir is affected by side flows between Crystal and Morrow Point:

$$mr_j \times G_{MP,j} + cr_j \times G_{CT,j} - ELEV_j + ELEV_{j+1} = SD_j \text{ for all j.} \tag{6.15}$$

In the above calculations,

cr_j = decrease in the elevation of Crystal Reservoir per unit of energy released through the Crystal Dam in hour j (ft/MWh), for j = 1, J;

d_j = Western's total firm and project use demands, for j = 1, J;

$DDNRMP_i$ = daily down-ramp rate restriction for hydropower plant i (MW/day), for i = 1, I;

$DUPRMP_i$ = daily up-ramp rate restriction for hydropower plant i (MW/day), for i = 1, I;

$ELEV_j$ = elevation at Crystal's water level at hour j (ft), for j = 1, J;

$G_{CT,j}$ = generation at the Crystal hydropower plant for hour j (MWh), for j = 1, J;

G_i = total energy from hydropower plant i (MWh), for i = 1, I;

$G_{i,j}$ = energy from each hydropower plant i, in hour j (MWh), for i = 1, I, and j = 1, J;

$G_{MP,j}$ = generation at the Morrow Point hydropower plant in hour j (MWh), for j = 1, J;

$HDNRMP_i$ = hourly energy down-ramp rate restriction for hydropower plant i (MW/h), for i = 1, I;

$HUPRMP_i$ = hourly energy up-ramp rate restriction for hydropower plant i, (MW/h), for i = 1, I;

$max_{i,j}$ = maximum hourly generation from hydropower plant i (MWh), for i = 1, I, and j = 1, J;

MAXEL = maximum reservoir elevation at Crystal (ft);

$min_{i,j}$ = minimum hourly generation for hydropower plant i at hour j (MWh), for i = 1, I, and j = 1, J;

MINEL = minimum reservoir elevation at Crystal (ft);

mr_j = rate of elevation increase at Crystal Reservoir per unit of energy released through the Morrow Point hydropower plant in hour j (ft/MWh), for j = 1, J;

SD_j = increase in the elevation of Crystal Reservoir due to side flows in hour j (ft), for j = 1, J; and

tot_i = total generation from hydropower plant i as estimated by the CRSS model, for i = 1, I, and j = 1, J.

6.3.2 Effects of Commitment-Level Alternatives on SLCA/IP Operations

Figures 10 through 13 show simulated hourly power plant operations and purchases and sales for a typical July day in 1993 under the four commitment-level alternatives. These figures show that with high operational flexibility, SLCA/IP hourly generation varies only slightly among commitment-level alternatives. That is, under *all* commitment-level alternatives, SLCA/IP generation is low during off-peak periods, ramps up rapidly in the morning, and ramps down at night. Minimum generation levels are constrained by minimum flow at each of the SLCA/IP power plants and by regulations for area load control. Maximum generation levels are constrained by maximum operational limitations at each power plant, area load control area regulations, and IPP spinning reserve obligations. The figures do not reflect fluctuations in SLCA/IP power plant generation to serve area load control and for the use of spinning reserves.

Assuming high operational flexibility, Western purchases energy during off-peak hours and sells non-firm energy during on-peak hours under all four commitment-level alternatives. Westerns' off-peak purchases depend on its firm loads. In general, the higher

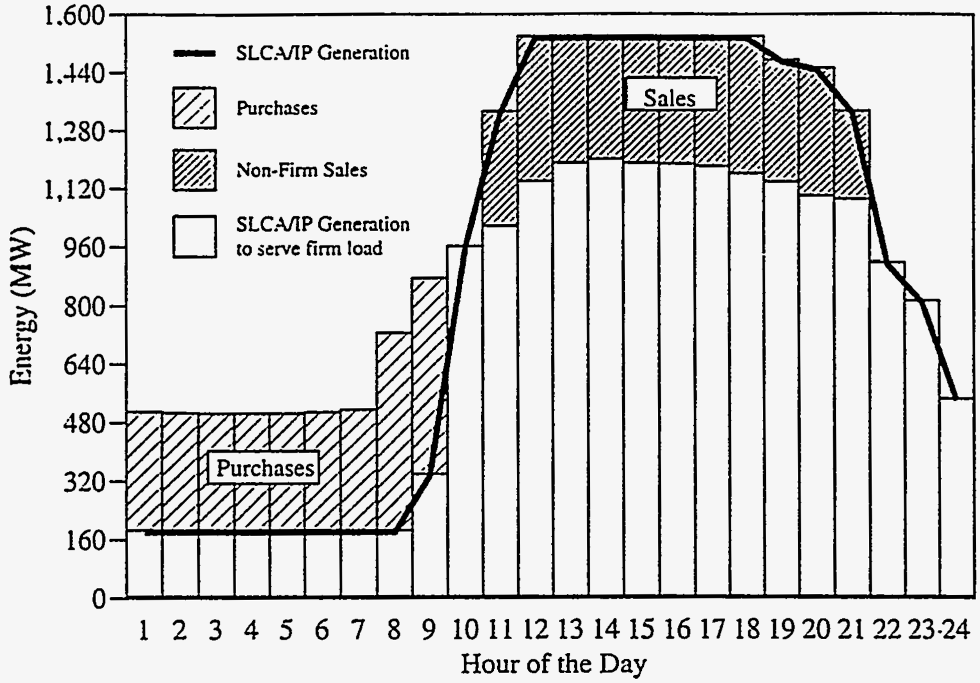

FIGURE 10 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in July 1993 under the No Action Alternative for the High-Flexibility Scenario (normal hydropower conditions)

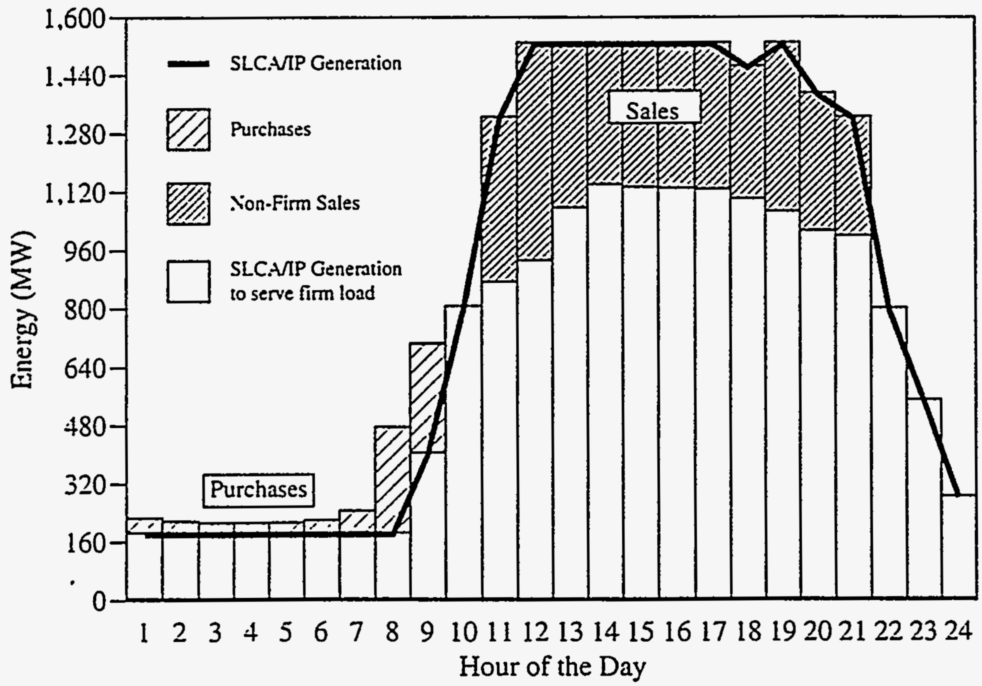

FIGURE 11 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in July 1993 under Alternative 2 for the High-Flexibility Scenario (normal hydropower conditions)

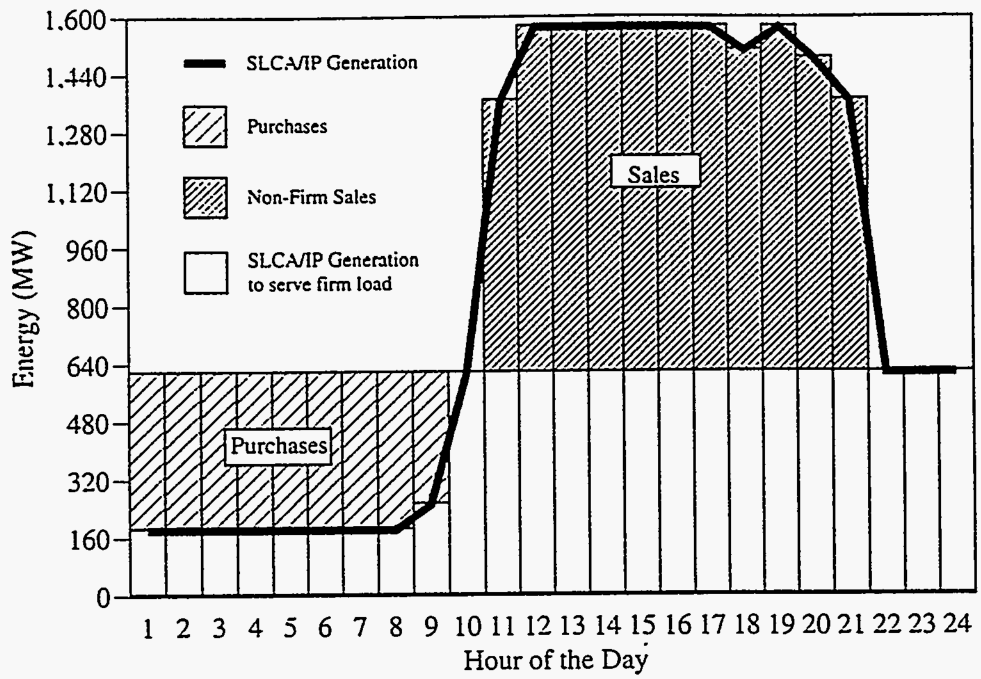

FIGURE 12 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in July 1993 under Alternative 4 for the High-Flexibility Scenario (normal hydropower conditions)

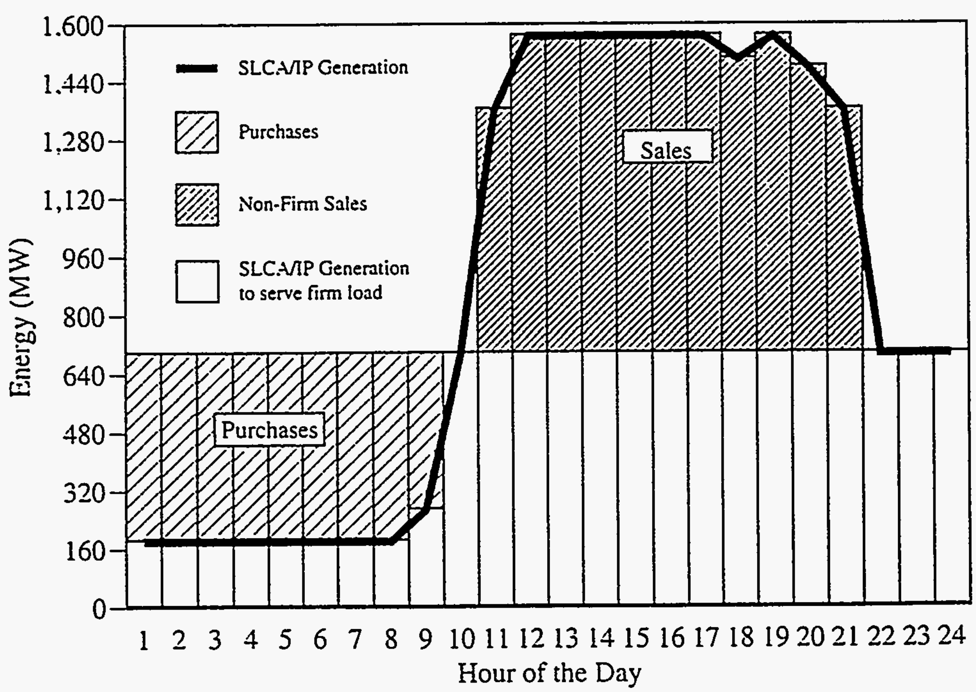

FIGURE 13 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in July 1993 under Alternative 5 for the High-Flexibility Scenario (normal hydropower conditions)

the off-peak firm load, the higher the level of purchases. These purchases allow Western to save water for release during on-peak periods. The lower the firm obligations during on-peak periods, the greater the on-peak non-firm sales. Under Alternative 4, SLCA/IP loads are constant at the summer CROD level plus project use because of large STF sales (Table 17). As described in Section 6.2, STF sales are made until the SLCA/IP purchases load factor reaches 100%.

In Figure 10 the peak load is slightly less than Western's summer CROD. As described in Section 6.3.1.1, the load reduction algorithm determines hourly SLCA/IP loads for each individual large SLCA customer. Demands for large customers are then aggregated and scaled to account for small customer loads and project use. For some customers who have low energy allocations relative to the CROD, insufficient amounts of energy are available to fully use the SLCA/IP power plant capacity all days of the month; that is, on some days, a customer may use less than its firm capacity (e.g., 90% of LTF capacity). In other cases, where the customer has high energy and relatively low capacity, the peak load reduction algorithm uses some discretionary energy to reduce off-peak loads. This use of energy minimizes the peak demand that remains after load shaving. In some situations, however, a utility system may request more discretionary energy on-peak even though it may result in off-peak loads that are higher than on-peak loads (i.e., after shaving). This strategy would allow the SLCA customer to sell more non-firm energy (generated from its resources) during on-peak periods.

Although Figures 10 through 13 show only slight differences in SLCA/IP hydropower plant generation among the four commitment-level alternatives, other situations show greater differences among power commitment-level alternatives. This fact is illustrated in Figure 14, which shows SLCA/IP hydropower plant generation curves in 1993 for the four power commitment-level alternatives. As explained in detail in Section 6.3.3, variations among alternatives are mainly attributed to hourly market prices. In July, the difference between hourly market prices during off- and on-peak hours is much higher than the difference during the fall and spring. Therefore, during July, there is a greater financial incentive to shift water from on- to off-peak periods. During a low load month, however, there are times when off- and on-peak price differentials are less than 3 or 4 mill/kWh. As a rule, a 3 mill/kWh difference between on- and off-peak prices is the minimum "transaction" margin that will trigger Western to engage in hydropower shifting activities. The 3 mill/kWh margin accounts for transmission losses and transaction costs. If this transaction margin is reduced, the generation patterns among power commitment-level alternatives would be more similar.

Under Alternative 5, SLCA/IP hydropower plant generation is at maximum firm load level (i.e., about 660 MW — CROD plus project use) more than 50% of the time (Figure 14). When differences between on- and off-peak hourly market prices are less than 3 mill/kWh, generation levels equal the firm load. However, when a price difference of more than 3 mill/kWh exists, generation is reduced to the minimum operating level when market prices are relatively low. The remaining firm loads are served via purchases. When market prices are relatively high, SLCA/IP hydropower plant generation levels are increased to their maximum generation level. By operating in this mode, Western can optimize its revenues, given the constraint of a 3 mill/kWh transaction margin.

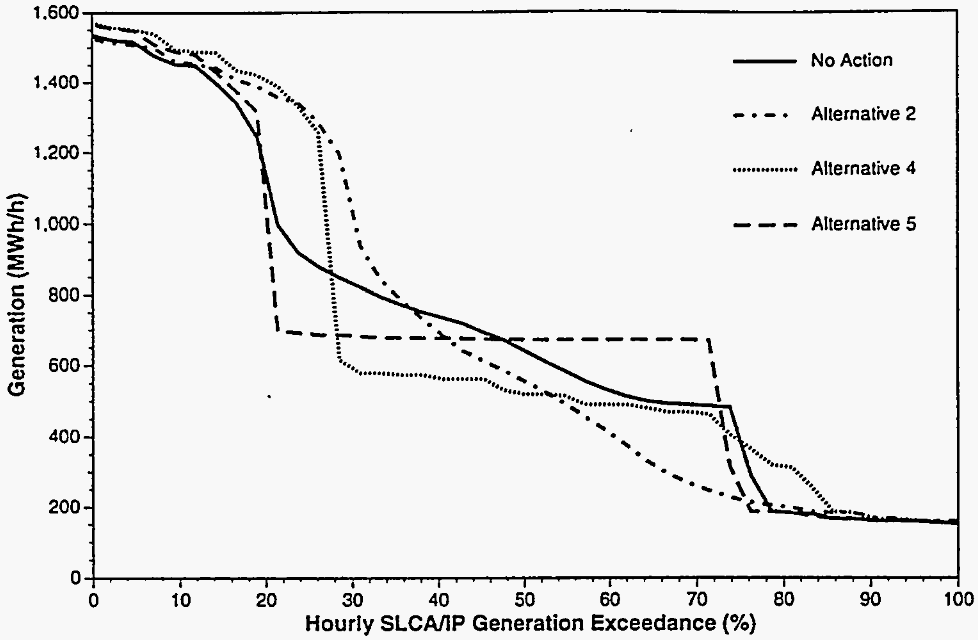

FIGURE 14 SLCA/IP Hydropower Plant Generation Exceedance Curves under Four Commitment-Level Alternatives for the High-Flexibility Scenario and Normal Hydropower Conditions for 1993

Without an actual trial under these conditions, it is extremely difficult to project Western's actual operations. However, because Hydro LP module simulations are driven by costs, the module tends to exaggerate changes in hourly operations under extreme conditions. For example, under Alternative 5, Western may choose a lower profit margin because firm loads are fixed and do not vary with time. Western would also tend to ramp over a longer time than simulated by the Hydro LP module. However, the Hydro LP module indicates the tendency of how operations are altered as a result of changes in commitment-level alternative.

Although SLCA/IP hydropower generation varies somewhat as a function of commitment-level alternative under the high-flexibility scenarios, variations in SLCA/IP hydropower plant generation are projected to be less under the medium-flexibility scenario. Figure 15 shows only slight variations among the commitment-level alternatives. In general, restrictions at only Glen Canyon Dam tend to increase generation fluctuations at other SLCA/IP hydropower plants. Increases in fluctuations at these facilities help compensate for operational flexibility losses at Glen Canyon. However, when operational limitations at Glen Canyon result in the transfer of load control and spinning reserve responsibilities to other power plants, such as Blue Mesa and Flaming Gorge, fluctuations at these plants may actually decrease.

As shown in Figure 15 maximum generation levels for Alternatives 4 and 5 are higher than maximum generation levels for the No Action Alternative and Alternative 2. Although

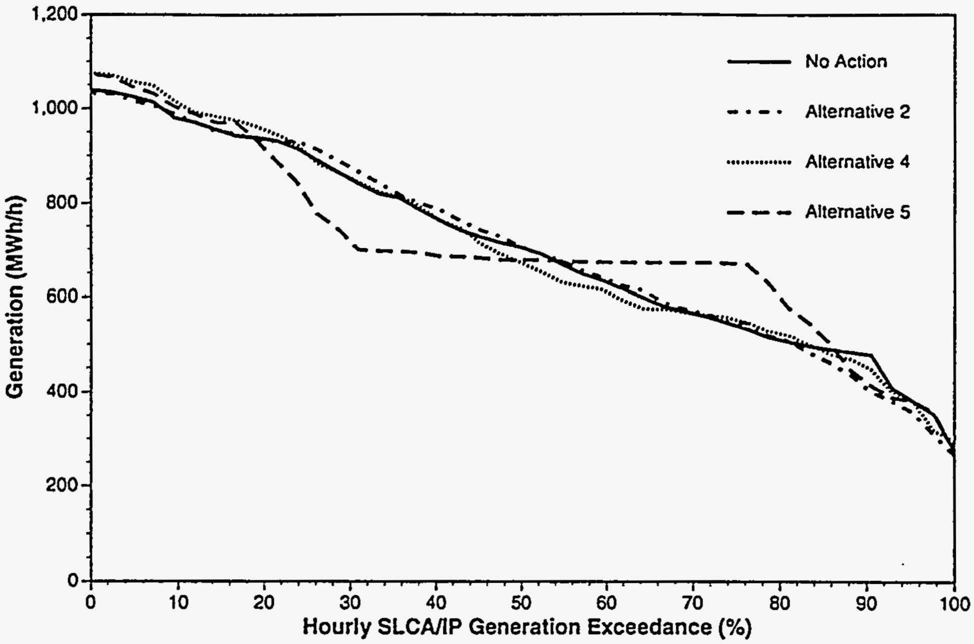

FIGURE 15 SLCA/IP Hydropower Plant Generation Exceedance Curves under Four Commitment-Level Alternatives for the Medium-Flexibility Scenario and Normal Hydropower Conditions for 1993

the physical generating capacity of SCLA/IP power plants for all four commitment-level alternatives is identical, differences in maximum generation levels occur because of differences in IPP spinning reserve obligations (Table 15).

6.3.3 Effects of Operational Scenarios on SLCA/IP Operations

Figures 10, 16, and 17 show projected hourly hydropower plant operations for a typical July day in 1993 under high, medium, and low operational flexibility, respectively. For the No Action Alternative, the figures show that as operational flexibility decreases, purchases shift from off- to on-peak hours. Under the high-flexibility scenario, all purchases are made at night and early morning, and non-firm sales are made during on-peak hours. Under the low-flexibility scenario, non-firm sales are made during the off-peak hours, and purchases are made during on-peak hours. Under the medium-flexibility scenario, non-firm sales are required at night because demand is reduced at a greater rate than the allowable down-ramp rate under the medium-flexibility scenario. Demands also have a larger range of fluctuation than the maximum allowable daily ramp rate.

Loss in operational flexibility not only restricts Western's ability to follow firm load; it also significantly reduces SLCA/IP hydropower plant capacity. As shown in the SLCA/IP hydropower plant generation exceedance curves in Figure 18, maximum generation levels among operational scenarios range from 1,600 MW under the high-flexibility scenario to approximately 950 MW under the low-flexibility scenario. Variations in the generation level

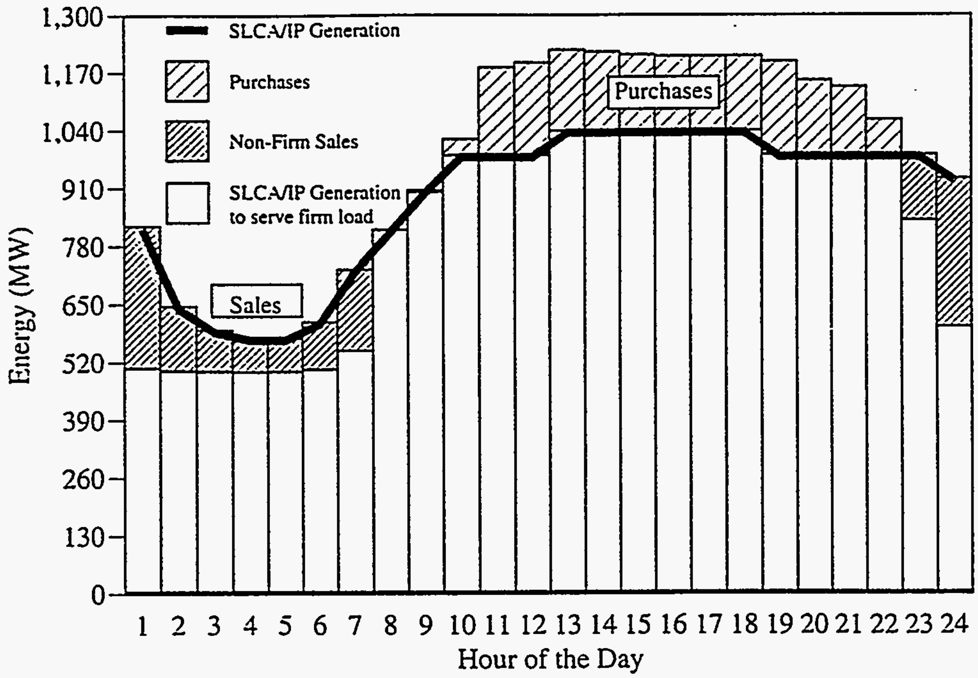

FIGURE 16 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in July 1993 under the No Action Alternative for the Medium-Flexibility Scenario (normal hydropower conditions)

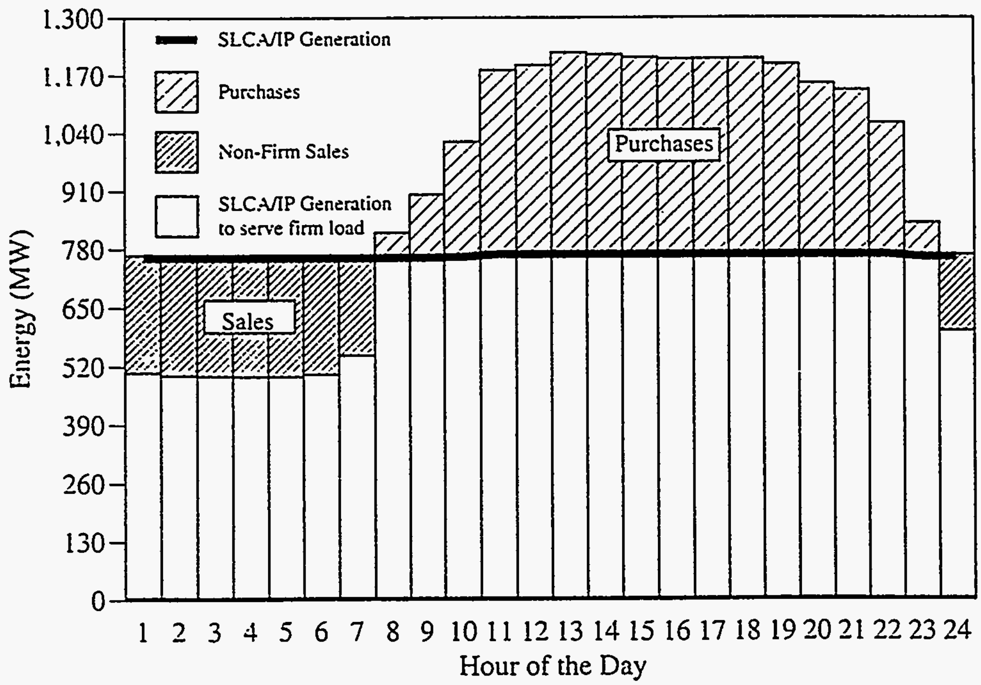

FIGURE 17 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in July 1993 under the No Action Alternative for the Low-Flexibility Scenario (normal hydropower conditions)

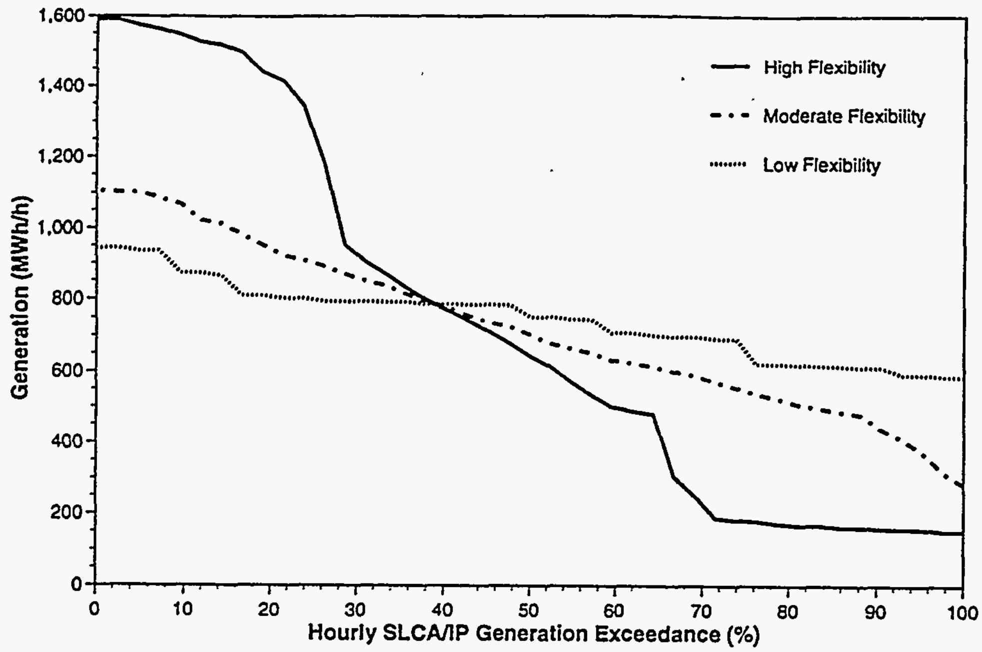

FIGURE 18 SLCA/IP Hydropower Generation Exceedance Curves under the Three Operational Scenarios and the No Action Alternative for 1998 (normal hydropower conditions)

under the low-flexibility scenario are caused by changes in monthly water volumes. Except for a transition period between months, generations within a month are constant.

6.3.4 Effects of Hourly Prices on SLCA/IP Operations

Hourly non-firm market prices are expected to increase over time; however, price increases for on-peak hours are projected to rise more rapidly than for off-peak hours. Figure 19 shows average SLCA purchase and sale prices for the No Action Alternative for the high-flexibility scenario under normal hydropower conditions. The figure shows that the cost of purchases made by Western (generally made during off-peak hours) increases at an annual average rate of 2.0% over the study period, while the cost of non-firm market sales increases by approximately 3.0% per year. This increase in prices reflects the fact that excess capacity in the Western marketing area decreases over time because of growth in demand. In addition, new gas-fired turbines with higher operating costs are projected to be built in the future to serve peak loads, and prices for oil and gas are projected to increase over time at a faster rate than coal prices. The projected higher price difference between off- and on-peak prices increases the economic incentive for Western to increase the amount of hydropower shifting in the future.

Figure 20 shows that under the No Action Alternative with normal hydrology, SLCA/IP hydropower plant operations are projected to fluctuate more in the future. In 2007, generation levels are at the minimum release level for approximately 45% of the time. This amount is substantially more than the time that SLCA/IP hydropower plant generation is at

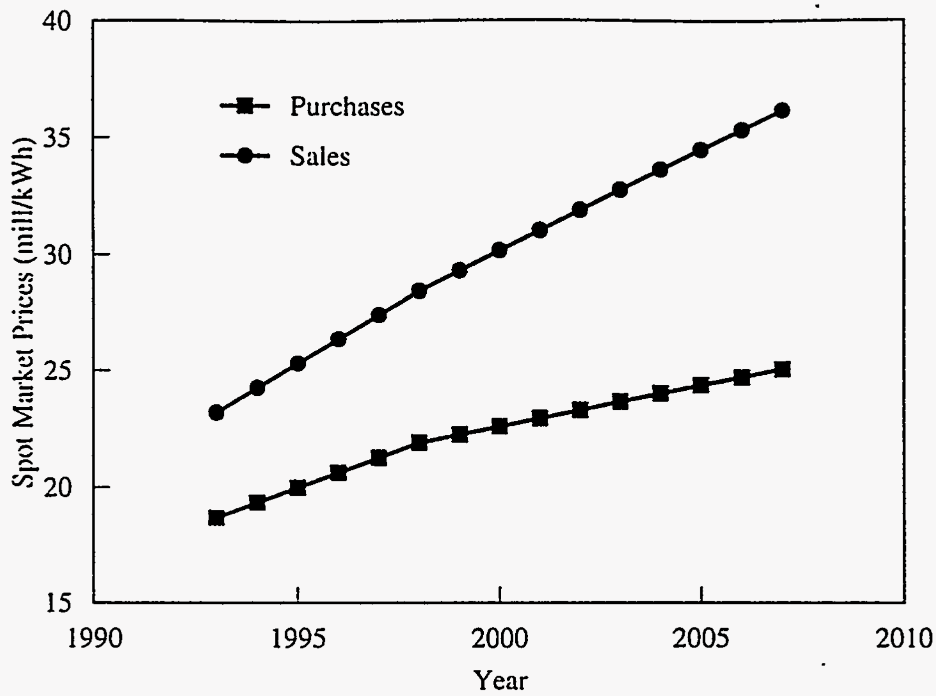

FIGURE 19 Projection of Western's Annual Average Energy Purchase and Sale Prices (in 1994 constant dollars)

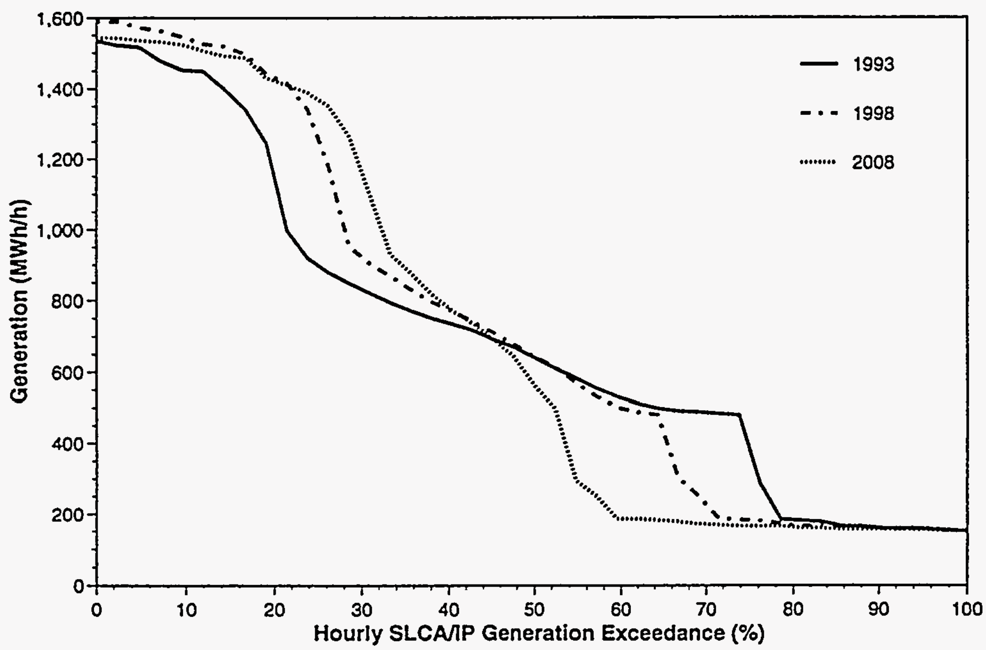

FIGURE 20 SLCA/IP Hydropower Generation Exceedance Curves under the No Action Alternative for the High-Flexibility Scenario and Normal Hydropower Conditions for 1993, 1998, and 2008

minimum flow levels in 1993 (i.e., about 20% of the time). On the other hand, relatively more generation occurs above the 900-MWh/h point in 2007 than occurs in 1993. Maximum generation levels in 1998 are also projected to be somewhat greater in 1998 than they are in 1993 and 2007.

The largest increases in hourly generation fluctuations are projected to occur in low load months. Peak load months such as July are projected to display a high degree of generation fluctuation in 1993 and have less potential for increasing generation fluctuations. Figures 21 and 22 show SLCA/IP hydropower plant generation for a typical day in October under normal hydropower conditions. Assuming the high-flexibility scenario and the no-action commitment-level alternative, SLCA/IP hydropower plant generation in 1993 follows Western's firm hourly loads during the day. At night, purchases are made to help meet loads. Because current reservoir conditions are low, normal hydropower conditions (as determined by the methodology presented in Section 6.1) are projected to be drier in 1993 than in other forecast years. Therefore, these off-peak purchases are made to compensate for the energy deficit. Because the market price during the on-peak hours is less than 3 mill/kWh higher than during shoulder hours, hydropower shifting does not occur. However, by 2007, significant hydropower shifting is forecast under normal hydropower conditions because off-peak purchases are not needed to compensate for an energy deficit, and the price differences among hours are significantly higher than in 1993. Increases in generation fluctuations over time are projected to be significantly reduced under the medium-flexibility scenario. Figures 23 and 24 show only minor differences between SLCA/IP hydropower plant operations in October 1993 and October 1998 under normal hydropower conditions.

Because hourly plant price differentials are projected to increase over time, Western's hydropower operations are expected to increasingly deviate from its hourly firm loads. Future operations will, therefore, be increasingly driven by market prices. As shown in Figure 25, hydropower plant operations vary substantially less across commitment-level alternatives in 2007 than they do in 1993 (Figure 14).

6.3.5 Effects of Hydropower Conditions on SLCA/IP Operations

As described in Section 6.1, hydropower conditions are projected to vary significantly over time. Figures 26 and 27 show projected hourly hydropower plant operations for a typical July day in 1998 under dry and wet hydropower conditions, respectively. The figures show that under the no-action commitment-level alternative with high operational flexibility, hydropower plant operations fluctuate dramatically from off- to on-peak hours. However, under wet conditions, hydropower plant generation is always at high levels. High levels of generation are needed to keep SLCA/IP reservoirs from spilling water.

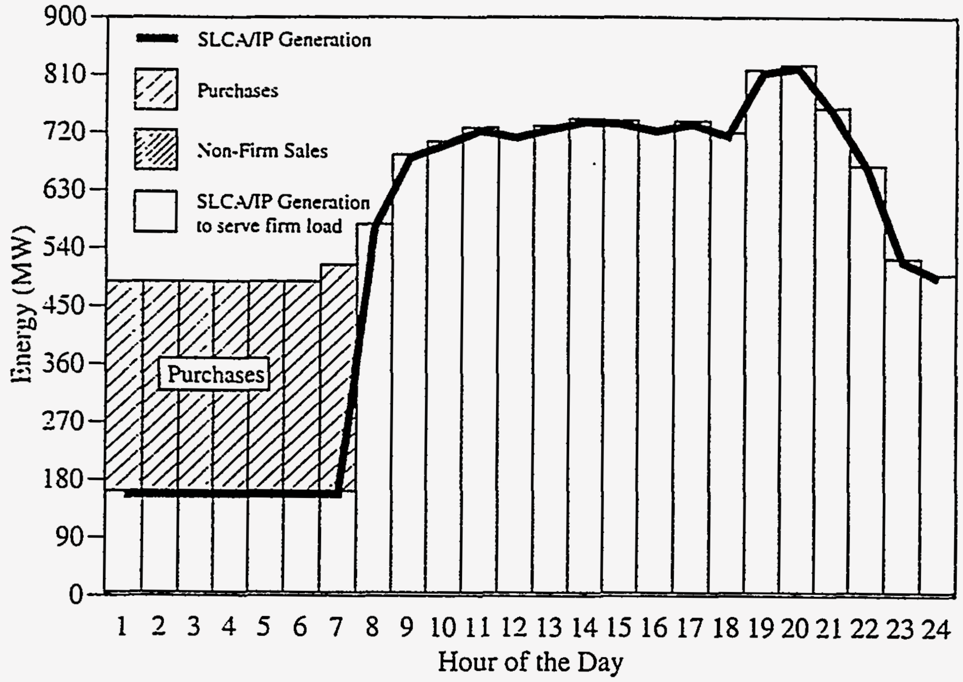

FIGURE 21 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in October 1993 under the No Action Alternative for the High-Flexibility Scenario (normal hydropower conditions)

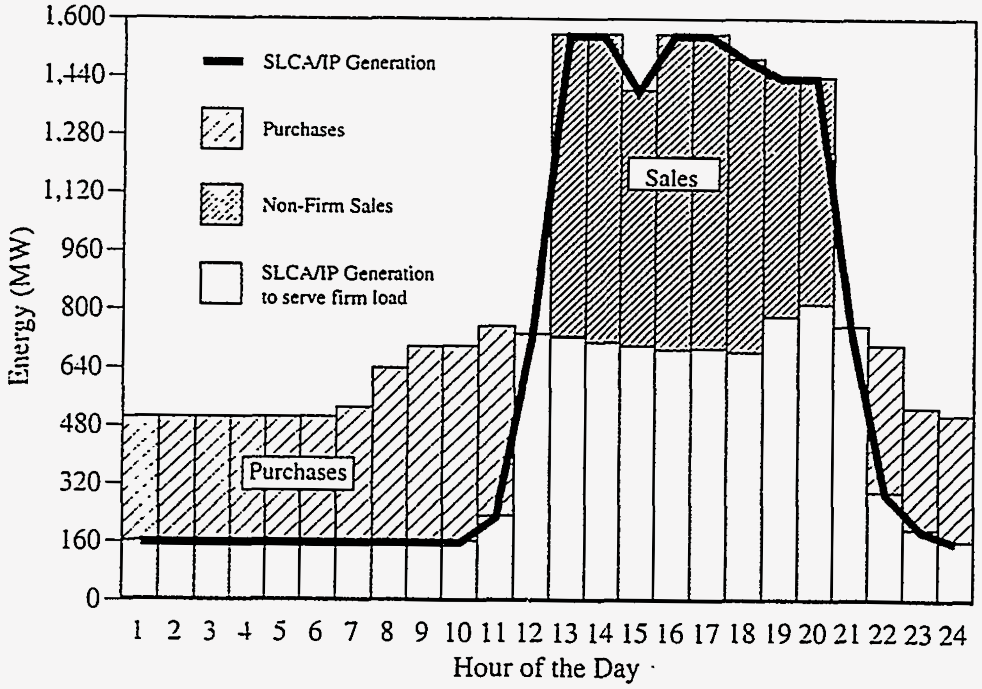

FIGURE 22 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in October 1998 under the No Action Alternative for the High-Flexibility Scenario (normal hydropower conditions)

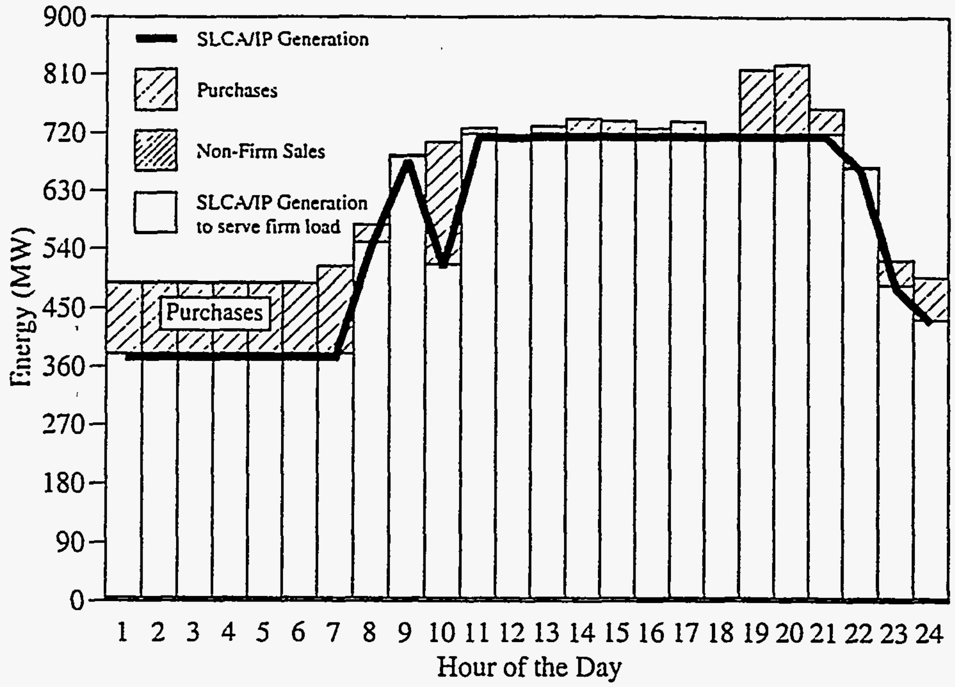

FIGURE 23 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in October 1993 under the No Action Alternative for the Medium-Flexibility Scenario (normal hydropower conditions)

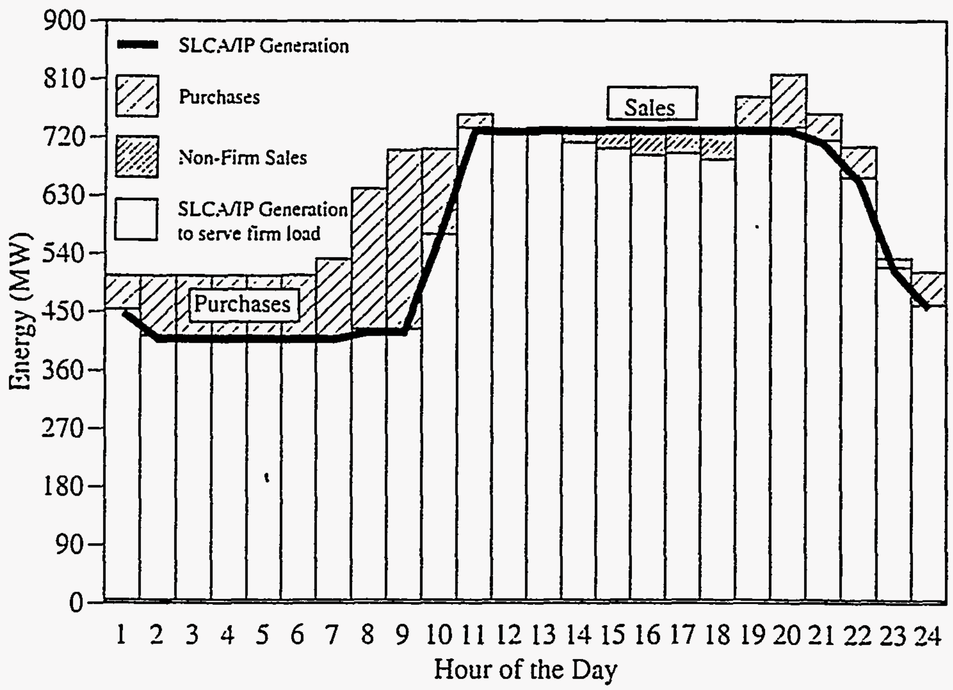

FIGURE 24 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in October 1998 under the No Action Alternative for the Medium-Flexibility Scenario (normal hydropower conditions)

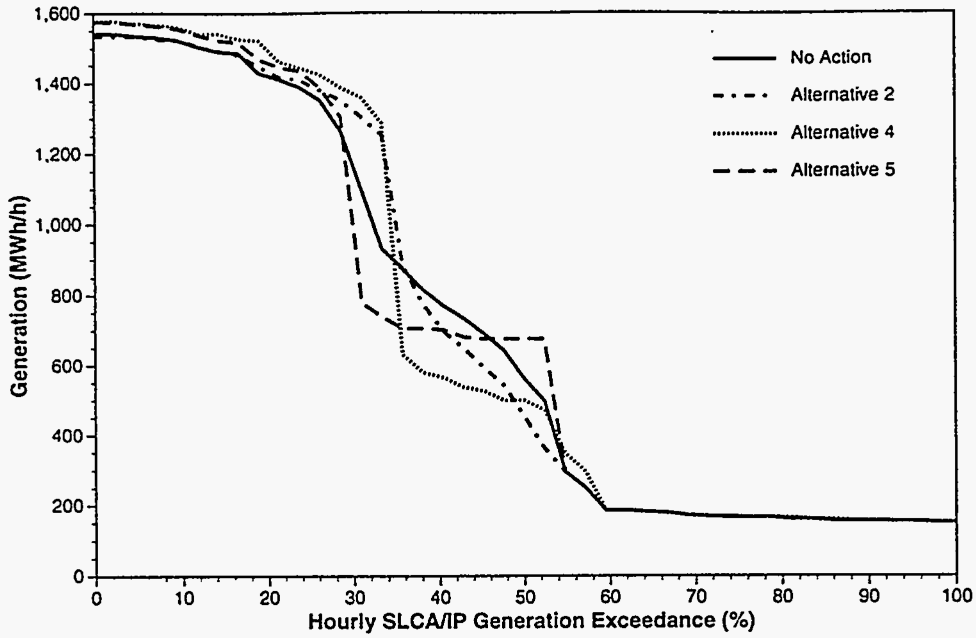

FIGURE 25 SLCA/IP Hydropower Plant Generation Exceedance Curves under Four Commitment-Level Alternatives for the High-Flexibility Scenario and Normal Hydropower Conditions for 2008

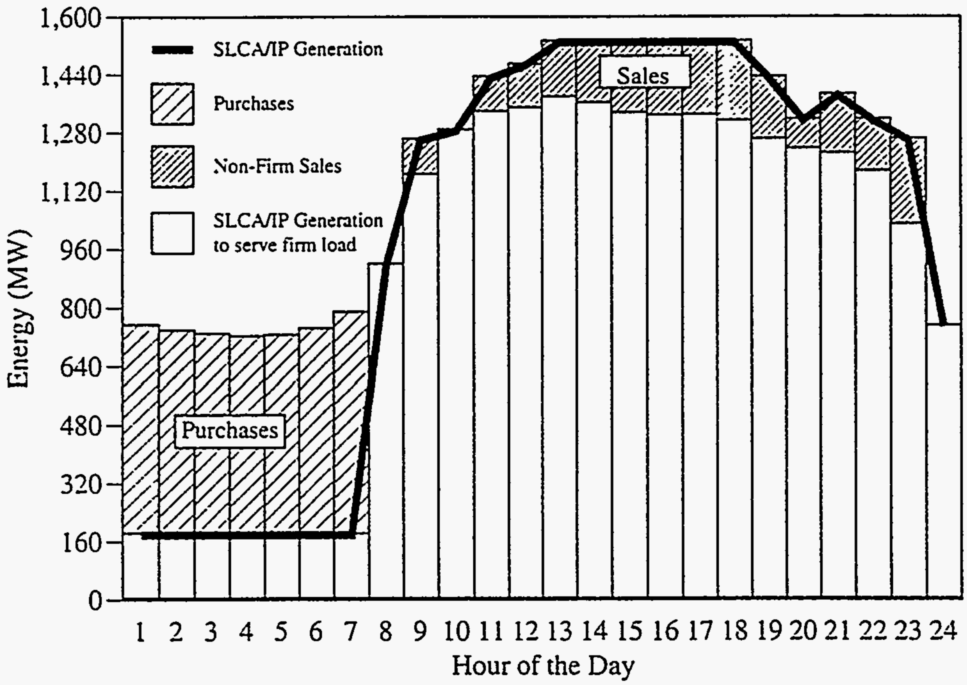

FIGURE 26 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in July 1988 under Alternative 2 for Dry Hydropower Conditions

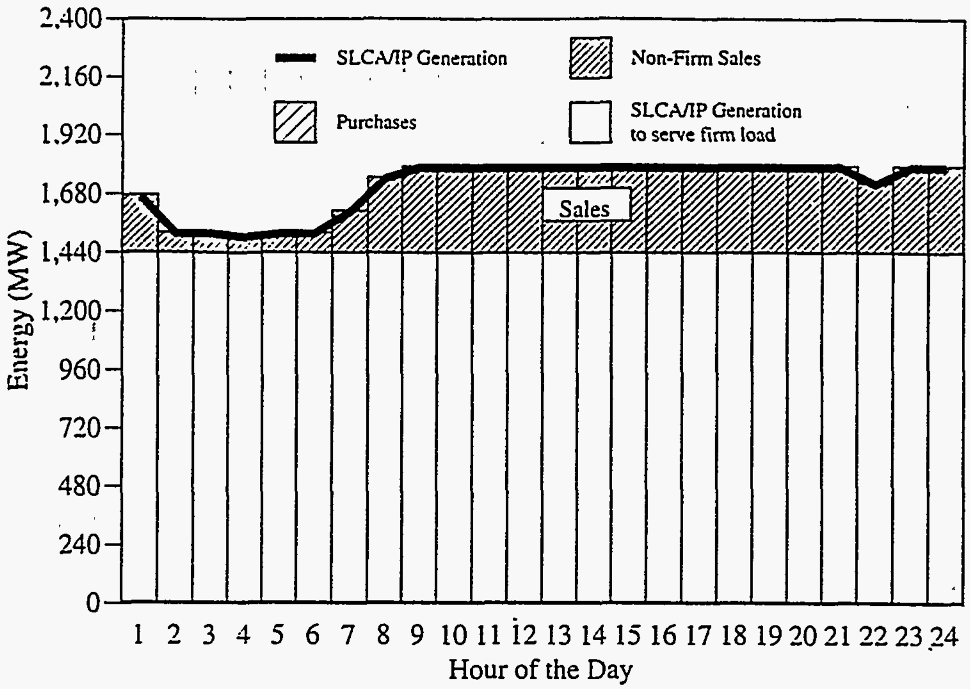

FIGURE 27 Simulated Hourly SLCA/IP Hydropower Plant Operations for a Peak Day in July 1988 under the No Action Alternative for Wet Hydropower Conditions

6.3.6 Summary of SLCA/IP Purchases and Sales

Table 18 summarizes Western's purchase and sales activities averaged over the 15-year LTF contract period by commitment-level alternative, operational scenario, and hydropower condition. Both purchases and sales are relatively low in 1993 and increase through 2007. The reason for this increase is because of a greater economic incentive for hydropower shifting in the future. The table shows that non-firm sales increase with wetter hydropower conditions. Increases in non-firm sales from dry to wet hydropower conditions are greater for Alternatives 4 and 5 than they are for the No Action Alternative and Alternative 2. This fact occurs primarily because no excess energy is sold on the STF market under Alternative 5, and STF energy sales under Alternative 4 are limited by LTF capacity sales (i.e., 550 MW with a 100% load factor). Alternative 2 has the lowest increase in non-firm sales from dry to wet hydropower conditions. This fact occurs because LTF energy sales are less than the amount of SLCA/IP hydropower plant energy produced under the most adverse hydropower conditions. The LTF capacity commitments are also high under Alternative 2, and excess energy above LTF commitments occurs under all hydropower conditions. Most of this excess is sold on the STF market (Table 17). Because LTF capacity is high, STF energy sales are rarely limited by the 100% load factor.

Non-firm sales as a function of hydropower flexibility also vary by commitment-level alternative. In general, the closer the match among operational restrictions and LTF

TABLE 18 Average Annual Purchases and Non-Firm Sales between 1993 and 2007 by Commitment-Level Alternative, Hydropower Condition, and Operational Scenario

	Operational Scenario					
	High Flexibility		Medium Flexibility		Low Flexibility	
Commitment-Level Alternative/ Hydropower Condition	Purchase[a] (GWh/yr)	Non-Firm Sale (GWh/yr)	Purchase[a] (GWh/yr)	Non-Firm Sale (GWh/yr)	Purchase[a] (GWh/yr)	Non-Firm Sale (GWh/yr)
No Action Alternative						
Dry	1,916	528	1,443	50	1,635	155
Normal	1,297	1,168	370	491	748	804
Wet	584	1,749	74	1,274	205	1,356
Weighted average	1,436	1,010	842	394	1,084	605
Alternative 2						
Dry	354	1,271	173	1,098	561	1,488
Normal	329	1,619	187	1,513	616	1,938
Wet	173	1,757	253	1,873	439	2,048
Weighted average	313	1,506	194	1,373	559	1,758
Alternative 4						
Dry	838	1,782	63	1,014	59	985
Normal	937	2,564	57	1,904	0	1,746
Wet	376	5,056	0	5,102	0	4,997
Weighted average	804	2,662	52	1,918	24	1,924
Alternative 5						
Dry	2,258	1,125	1,406	268	1,224	0
Normal	1,721	1,847	500	958	184	521
Wet	580	4,069	16	3,927	0	3,807
Weighted average	1,753	1,929	854	1,030	620	796

[a] Purchases include LTF, STF, and spot market energy.

commitments, the lower the level of purchases and non-firm sales. For example, under Alternative 5, the weighted average non-firm sales tend to decrease with reductions in operational flexibility. Under the No Action Alternative, the medium-flexibility scenario results in the lowest level of non-firm sales. The high-flexibility scenario leads to large off-peak purchases to store energy for non-firm sales during on-peak periods. Hourly load changes under the low-flexibility scenario often require Western to make large purchases and non-firm sales. Under the medium-flexibility scenario, when Western customers have a high LTF capacity allocation, non-firm sales are made during shoulder hours when customer's hourly demands are changing rapidly. That is, customers' loads change more rapidly than maximum allowable hourly hydropower plant ramp rates, and sales on the non-firm market are often required.

Under the high-flexibility scenario, purchases are primarily a function of minimum firm load levels. The lower the minimum schedule requirement, the lower the purchase level. This relationship is valid to the point where the minimum schedule requirement is equal to the SLCA/IP minimum generation level. The higher the minimum schedule requirements, the more purchases Western makes to serve customer firm loads during off-peak hours. The minimum schedule requirement allows Western to purchase relatively inexpensive energy during off-peak hours to offset low energy production levels during dry periods.

Under the medium-flexibility scenario, purchases tend to be less than under the high-flexibility scenario. When Western customers have high LTF capacity allocations, most of these purchases are made during on-peak hours because daily ramp rate restrictions at Glen Canyon limit the maximum amount of hourly generation from SLCA/IP hydropower plants. However, when Western sells relatively low levels of LTF capacity, most purchases are made during off-peak hours.

7 DETERMINING LEAST-COST CAPACITY EXPANSION PATHS

Although many of the utility systems modeled in detail currently have excess capacity, additional supply-side resources will be needed in the future. The additional resources built or purchased in the future depend on several factors. Some of the most important factors include (1) future load growth, (2) existing generating capacity, (3) LTF agreements with other utility systems, (4) committed or announced units, (5) projected contributions from non-utility generating (NUG) sources, and (6) reliability goals or targets. Of particular interest in this study is the effect of decreases in Western's LTF capacity and energy allocations, as specified in commitment-level alternatives on customer capacity expansion plans. Utility-level capacity expansion plans were estimated for each of the four commitment-level alternatives studied in detail.

Argonne used a multistage process to determine least-cost expansion paths for each large LTF customer. First, ANL determined the total additional capacity required by a utility system to achieve a specific reserve margin. The candidates for capacity expansion were then selected on the basis of the additional capacity required by the system, the characteristics of the utility system, and a screening process. The screening process reduces the large number of potential capacity expansion candidates (approximately 100) to a number of candidates that can be studied in more detail. Finally, ANL uses the BUILD module of the Production and Capacity Expansion (PACE) model to determine the least-cost supply expansion path using dynamic programming (DP) techniques.

Least-cost capacity expansion plans are estimated twice. Capacity expansion plans are estimated with initial forecasts of a utility system's hourly loads. On the basis of results from this initial capacity expansion plan, DSM modelers estimated the penetration of DSM programs and the effects of the economic programs on hourly loads. Capacity expansion plans are then estimated a second time based on the hourly loads adjusted for DSM programs.

7.1 CAPACITY EXPANSION REQUIREMENTS

Total supply expansion requirements are based on a minimum reserve margin target. When the reserve margin is projected to fall below the minimum, additional resources must be built or purchased. The additional capacity needed to meet the reserve margin is computed by the following equation:

$$\begin{aligned} CD = {} & [PL \times (1 - DF) \times (1 + LF) + NLTFS - NLTFP] \\ & \times (1 + RM) - SC - CLTFP + CLTFS \ , \end{aligned} \tag{7.1}$$

where

CD = capacity deficit (MW),

SC = system on-line capacity (MW),

CLTFP = contingent LTF purchases (MW),

CLTFS = contingent LTF sales (MW),

PL = system peak load (MW),

DF = diversity factor (fraction),

LF = transmission loss factor (fraction),

NLTFS = noncontingent LTF sales (MW),

NLTFP = noncontingent LTF purchases (MW), and

RM = reserve margin (fraction).

Capacity deficits are computed on either a monthly or an annual basis, depending on the characteristics of the system. If computations are performed on an annual basis, capacity expansion calculations are based on the annual peak load. For some systems that have a small number of units (i.e., fewer than four), monthly capacity deficits are examined. This procedure is important because one unit on maintenance during a low load period (e.g., spring and fall) can result in a large capacity deficit.

7.2 SUPPLY-SIDE TECHNOLOGY OPTIONS

Additional generating units may be needed in future years to replace retired units, to satisfy growth in demand, and to replace expired LTF contracts. Argonne examined several supply-side technology options and one generic LTF contract for consideration into utility supply expansion plans. Cost and performance characteristics of candidate technologies were determined on the basis of hypothetical "generic" units. The technologies considered for capacity expansion in this study are listed in Appendix D.

Costs for both LTF and STF purchases were $193/kW-yr for capacity and 17.1 mill/kWh for energy. Capacity purchase amounts were tailored for each utility system, and energy purchases were based on a utility dispatch routine (Section 9). These costs are consistent with LTF purchase costs used in the Glen Canyon EIS and are a reasonable estimate of current firm capacity and energy purchase costs.

7.2.1 Consistency among Technologies

Because costs for new expansion depend on unit size, overall consistency within a technology group is achieved by normalizing costs to place them on a common basis. Total capital cost (TCC) approximately follows this relationship with respect to capacity:

$$TCC_1 = TCC_2 \times (MW_2/MW_1)^c \, , \tag{7.2}$$

where the exponent c varies from 0.4 to 0.9, averaging approximately 0.6.

Uneconomical technologies were screened by comparing levelized annual costs in terms of mills per kilowatt-hour for electricity generation as a function of the capacity factor. This procedure allows for a comparison of technologies at different capacity factors. The objective is to determine technologies that will result in the lowest cost for electricity generation over a range of capacity factors.

The equation used to determine the total levelized annual cost (TLAC) as a function of capacity factor (CF) is

$$\begin{aligned} \text{TLAC} &= [(\text{TCC} \times \text{FCR}) + (\text{FO\&M} \times \text{LF})] + \text{CF} \times (8{,}760\ \text{h/yr}) \\ &\quad \times [(\text{FC} \times \text{HR} \times \text{LF}/10^6) + (\text{VO\&M} \times \text{LF}/1{,}000)]\ , \end{aligned} \tag{7.5}$$

where

TLAC = total levelized annual cost ($/kW-yr),

TCC = total capital cost ($/kW),

FCR = fixed charge rate (fraction/yr),

FO&M = fixed operations and maintenance (O&M) cost ($/kW-yr),

LF = levelizing factor,

CF = capacity factor (fraction),

FC = fuel cost ($/10^6 Btu),

HR = average annual heat rate (Btu/kWh), and

VO&M = variable O&M cost, including consumables and by-products (mill/kWh).

The levelizing factor (LF) is given by

$$\text{LF} = \text{A} \times [\text{k} \times (1 - \text{k}^n)]/(1 - \text{k})\ , \tag{7.6}$$

where

$k = (1 + e)/(1 + r)$,

$A = [r \times (1 + r)^n]/[(1 + r)^n - 1]$, and where

e = apparent annual escalation rate (fraction/yr),

r = discount rate, also called weighted cost of money (fraction/yr), and

n = book life of the particular electricity-generating technology (yr).

7.2.4 Fuel Prices of New Units

Average historical state-level fuel prices shown in Table 20 for 1987 through 1991 are used for new coal-fired units. Fuel prices for fuel oil and natural gas are both assumed to be 246.0¢/MMBtu. Biomass fuel prices were assumed to be 883.0¢/MMBtu, while the price for nuclear fuel was 64.0¢/MMBtu.

Table 21 shows fuel escalation rates assumed in this study. These escalation rates are in real terms and are applied to fuels consumed at both new and existing power plants. Fuel escalation rates through 2010 were obtained from Data Resources, Inc. (DRI) for the fourth quarter of 1991 and are consistent with the rates used in Glen Canyon Dam EIS power system analyses. Escalation rates for the years 2011 and 2012 were assumed to be equal to the rates for 2010.

TABLE 20 Historical State-Level Coal Prices (in 1994 dollars)[a]

Year	Arizona	Colorado	Nevada	New Mexico	Utah	Wyoming
1984	163.7	153.3	180.0	126.2	181.2	130.2
1985	171.5	151.4	212.4	143.3	179.8	120.6
1986	174.5	150.3	177.9	144.9	180.0	118.0
1987	161.1	138.6	173.5	149.8	155.2	107.9
1988	168.6	127.9	163.6	141.0	151.8	100.8
1989	156.7	122.7	175.2	142.7	142.8	97.4
1990	158.3	117.4	165.1	145.9	129.2	92.6
1991	150.7	116.4	150.5	147.3	127.8	89.0
1987-1991[b]	159.1	124.6	165.6	145.3	141.4	97.5

[a] Fuel prices were adjusted using the gross national product deflator. The 1994 price index was estimated and set to 10.5% higher than 1990's value.

[b] Five-year average.

Sources: 1984-1986 price data from DOE (1990) and 1987-1991 price data from DOE (1992a).

TABLE 21 Real Fuel Escalation Rates[a]

	Coal		Natural Gas		Oil Products		Nuclear	
Year	Mountain Region 1[b]	Mountain Region 2	Mountain Region 1	Mountain Region 2	Mountain Region 1	Mountain Region 2	Mountain Region 1	Mountain Region 2
1991	-3.6	-4.2	4.0	3.0	10.2	9.8	2.1	2.1
1992	-0.8	0.2	1.1	1.0	11.5	10.6	3.0	3.0
1993	-0.7	-1.1	2.8	3.1	9.2	8.1	3.8	3.8
1994	-0.7	-1.3	3.6	2.7	2.4	3.3	2.8	2.8
1995	-0.3	-0.6	6.4	5.1	4.9	4.9	3.3	3.3
1996	-0.3	-0.6	6.4	5.1	4.9	4.9	3.7	3.7
1997	-0.3	-0.6	6.4	5.1	4.9	4.9	4.8	4.8
1998	-0.3	-0.6	6.4	5.1	4.9	4.9	5.1	5.1
1999	-0.3	-0.6	6.4	5.1	4.9	4.9	6.1	6.1
2000	0.5	0.5	4.4	3.8	3.1	3.1	6.0	6.0
2001	0.5	0.5	4.4	3.8	3.1	3.1	5.5	5.5
2002	0.5	0.5	4.4	3.8	3.1	3.1	5.1	5.1
2003	0.5	0.5	4.4	3.8	3.1	3.1	4.7	4.7
2004	0.5	0.5	4.4	3.8	3.1	3.1	4.1	4.1
2005	0.5	0.5	4.4	3.8	3.1	3.1	3.6	3.6
2006	0.5	0.5	4.4	3.8	3.1	3.1	3.5	3.5
2007	0.5	0.5	4.4	3.8	3.1	3.1	3.4	3.4
2008	0.5	0.5	4.4	3.8	3.1	3.1	3.1	3.1
2009	0.5	0.5	4.4	3.8	3.1	3.1	2.8	2.8
2010	0.5	0.5	4.4	3.8	3.1	3.1	2.5	2.5
2011	0.5	0.5	4.4	3.8	3.1	3.1	2.5	2.5
2012	0.5	0.5	4.4	3.8	3.1	3.1	2.5	2.5

[a] Fuel cost escalation rates were obtained from Data Resources, Inc., (DRI) for the fourth quarter of 1991 and are consistent with the rates used in power system studies for the Glen Canyon EIS.

[b] Mountain Region 1 and Mountain Region 2 refer to DRI regions.

7.3 DETERMINING LEAST-COST SUPPLY-SIDE EXPANSION PATHS

The least-cost capacity expansion path for a utility system depends on a number of factors. The most important factors include (1) the mix of existing and announced resources, (2) future demand characteristics (peak load levels and load shapes), (3) assumed cost and performance characteristics of viable technology options, (4) projected fuel costs, and (5) current and future financial climates.

Argonne used the PACE model to determine the least-cost capacity expansion path, subject to a number of constraints, including minimum acceptable system reliability standards. An overview of the BUILD module's capacity expansion algorithm is depicted in Figure 28. For this study, reliability tests only included specified reserve margin targets provided by utility systems.

The first step in the modeling process is to generate different combinations of new unit additions that satisfy capacity expansion requirements for each year in the study. If the number of potential combinations is large, combinations can be constrained by specifying minimum and maximum penetration levels for each technology.

The second step in the PACE modeling process adds new units to a system. Units are temporarily created for each year and technology combination identified in the first step. For each inventory, the ICARUS module of PACE is run. ICARUS is a detailed production cost algorithm that estimates unit-level capacity factors, total variable O&M costs, system loss-of-load probability, and levels of unserved energy (see Section 8 for more detail).

The final step of the modeling process determines the least-cost expansion path through time. BUILD selects this path by assembling various combinations of expansion "snapshots" into a time sequence of capacity expansion options. PACE uses a dynamic modeling approach that significantly reduces the number of paths that must be explored in order to arrive at the least-cost solution. This solution is achieved through several modeling techniques. First, combinations that do not pass initial screening tests, as defined by the user, are eliminated from further consideration. Paths that are not plausible between time periods are then eliminated. For example, if time period T has two new pulverized coal-fired units, but only one coal-fired unit is in time period T + 1, that path is not considered as a viable option and is eliminated. A path is also eliminated if a less expensive path is available to a specific endpoint in time.

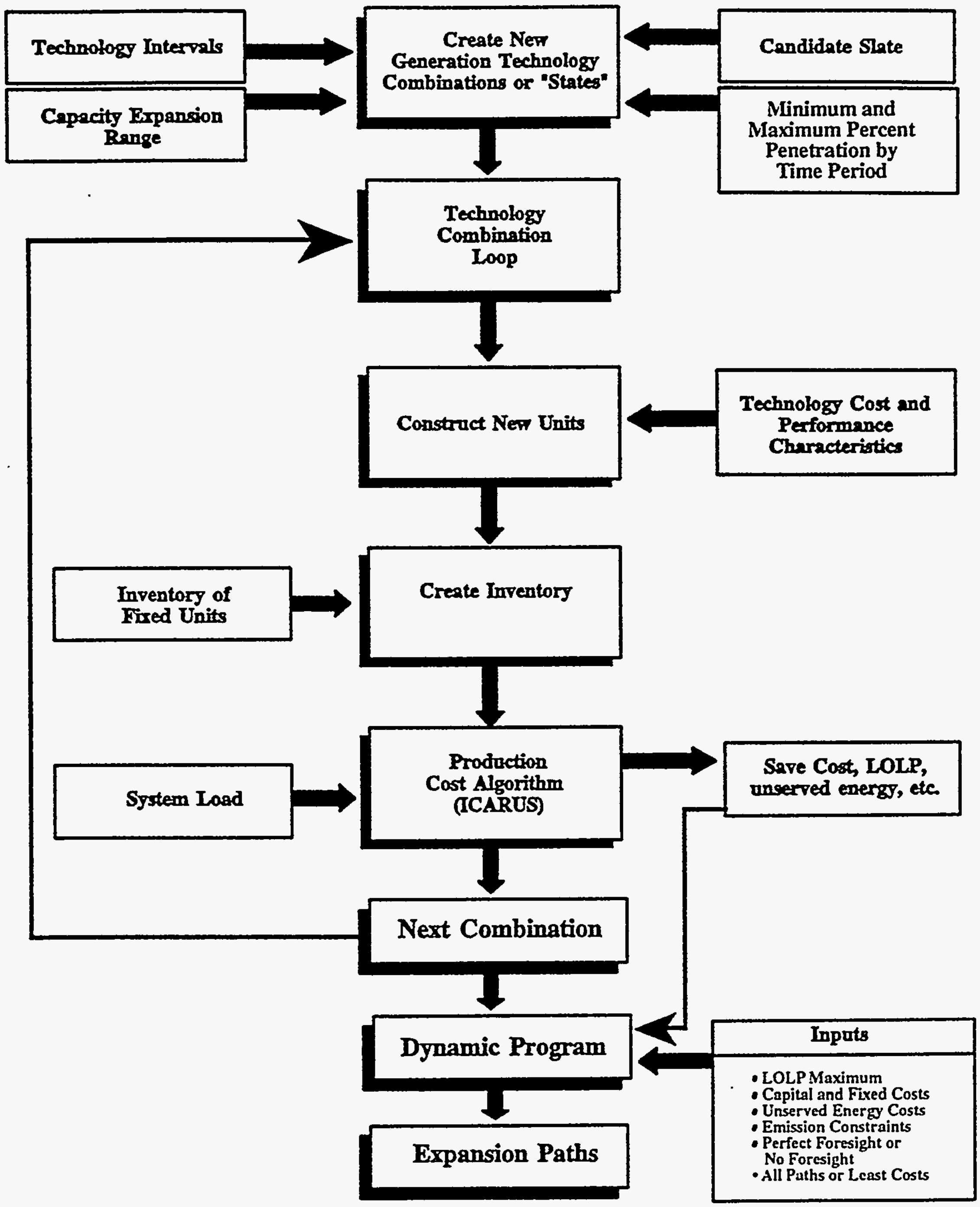

FIGURE 28 Overview of the PACE Build Module Capacity Expansion Algorithm (LOLP denotes loss-of-load probability)

8 UTILITY SYSTEM DISPATCH

As described in Section 7.3, estimates of future electricity production costs under many configurations of potential expansion candidates are required for forecasting a least-cost capacity expansion path. The ICARUS module and other complementary modules are used to estimate system-level production to satisfy loads. Future production costs depend on system loads, DSM programs, and supply resources. Supply resources include thermal and nonthermal generating resources and energy purchases.

8.1 REPRESENTATIVE HOURLY LOAD FORECAST

The PACE model uses historical hourly load data at the utility level to construct a "typical" normalized hourly load year. Hourly load data were supplied by the utility systems under investigation and are generally proprietary information. This typical load year is a set of 8,760 (one for each hour of the year) normalized values that, in aggregate, represent historical monthly load factors and cumulative load duration curve shapes. These normalized loads, along with peak and total loads, are used to project future loads.

8.1.1 Constructing Typical Normalized Hourly Loads

The procedure described here for constructing the typical load year filters out abnormal load patterns that occur because of unusual weather conditions and other atypical events. This procedure begins with constructing inverted normalized load duration curves for each month for which historical load data are available. The curve is constructed by ranking hourly loads from highest to lowest for each month. The fraction of time that each hourly load is exceeded during the month is then calculated. The highest hourly load is never exceeded and is assigned an exceedance fraction of 0.0, while the lowest hourly load is always exceeded and is assigned an exceedance fraction of 1.0. Each hourly load is then divided by the maximum hourly load in the month, and the curve is inverted.

When multiple years of load data are available for a utility system, normalized monthly loads that are most representative of average conditions are used. For example, if five years of historical information is available, the module selects one of the five January months that best represents average conditions. The representative monthly curve is selected on the basis of the month's normalized load shape and load factor relative to the other months.

After normalized load shapes have been constructed, average normalized load shapes are constructed for each month by computing arithmetic means at intervals of 0.01 exceedance fraction. The root-mean-square error difference between each historical load curve and the average load curve is computed. Load factors for each historical load curve and the average load curve are also computed. In case of a tie (i.e., one curve has the best load factor and the other has the best curve fit), the analyst makes the selection.

The representative load year can be composed of normalized monthly data from several different years. For example, January can be represented by 1987 data, while February can be represented by 1985 data, and March by 1990 data. Because the selection process is based on normalized load shapes and load factors, only relative load shapes are important; load magnitudes are ignored.

8.1.2 Hourly Load Forecast

The typical normalized hourly load year and an annual load projection are the basis for projecting hourly loads for all forecast years (1993-2012). Load forecasts provided by the utilities are used for 1993 through 1995 inclusive and are typically in the form of annual or monthly peak and total load growth rates. After 1995, loads are projected by applying growth multipliers to the 1995 load forecast. Argonne load forecasters estimated the annual growth rate multipliers (Cavallo et al. 1995).

Forecasts provided by some of the utilities were for noncoincidental loads. That is, monthly peak loads for individual members or load centers were totaled without regard for the time in the month in which the peaks occurred. These monthly peak load forecasts were lowered to estimate a coincidental peak demand. This task was achieved by multiplying the peak load by a diversity factor. Diversity factors are system dependent and usually vary by month.

An initial hourly load forecast was obtained by multiplying normalized values from the typical hourly load year by the forecasted peak load for a given month or year. Initial loads were then adjusted or "shaped" when the total demand (i.e., sum of the hourly loads) for a forecast month did not equal the monthly total demand forecast. This situation occurs when the load factor for the typical month does not agree with the monthly load factor implied by the monthly load forecast. The load shaping technique used in this analysis modified hourly loads on the basis of the difference between the hourly load value and the peak load. Adjusted loads were computed by the following equation:

$$\begin{aligned}\text{Adjusted load} &= \text{initial hourly load} + \text{adjustment factor} \\ &\quad \times (\text{peak load} - \text{initial hourly load}).\end{aligned} \tag{8.1}$$

A positive adjustment factor yields hourly load curves that have a higher load factor than that of the original load data. A negative adjustment factor yields loads that have lower load factors.

When load forecasts do not include system losses, hourly loads are multiplied by a loss factor. The loss factor is system dependent and applied to all hourly loads. Typical losses are mainly attributed to transmission line losses and vary from approximately 4 to 7%.

8.2 PRODUCTION COST MODELING BY ICARUS

Electricity production and costs were estimated by the ICARUS module. The ICARUS module calculates system costs and generating unit assignments over time and estimates system reliability (Guziel et al. 1990).

8.2.1 Load Representation

The ICARUS module is a probabilistic algorithm that uses load duration curves (LDCs) to estimate block-level capacity factors. For this analysis, hourly load forecasts are used to construct LDCs. For some utilities, hourly load forecasts are altered before being input into ICARUS in order to represent LTF contractual agreements between utility systems or other special circumstances (Section 8.3). Cumulative LDCs are generated from the hourly load forecasts by specifying the duration of the load (normalized to the total hours in the period) and the load magnitude (normalized to the period peak load).

For the power marketing EIS, LDCs were constructed for 26 periods for each year in the study (i.e., 1993 through 2012). Forty-two data points represented each LDC. Each period in ICARUS represents approximately two weeks. ICARUS computes the energy demand of an electric generating system by using the annual peak load, period peak loads, and LDCs. System dispatch is then done for each period.

8.2.2 Unit Representation

The ICARUS module can simulate an electric utility system with as many as 600 generating units. To simulate realistic loading behavior, each unit can be divided into a maximum of two capacity blocks: the base block and the peak block. This feature allows ICARUS to represent generating units that can operate at partial capacities. Although the generating units usually represent thermal generating units, they can also represent contracts between utility systems (Section 8.3) as a means of estimating the amount of energy that is curtailed to interruptible power customers.

When modeling jointly owned units with ICARUS, the unit is split into two or more units based on ownership fractions. For example, Colorado-Ute owns 50% of the Hayden-2 plant, and SRP owns the other half. The unit, which has a summer capacity of 262 MW, is modeled as a 131-MW unit in the Colorado-Ute system and as a 131-MW unit in the SRP system.

Physical characteristics of jointly owned units such as equivalent forced outage rate and heat rate curves are consistently modeled for each utility's share of a jointly owned unit. Because maintenance outages could significantly affect spot market activities, each portion of the jointly owned unit, as modeled by ICARUS, has the same maintenance schedule. However, O&M and fuel cost characteristics for each utility of a jointly owned unit can vary because of contractual arrangements in which each owner may pay different costs.

8.2.3 Maintenance

The maintenance schedule for an electric utility system affects both reliability and cost. In the ICARUS module, system maintenance is specified in one of three ways: (1) it is entered by the user; (2) it is partially specified by the user; or (3) it is completely determined by the model.

Generating unit input data include the number of weeks per year of maintenance for each unit and the week in which maintenance begins. A unit that requires two weeks of maintenance is unavailable for one period during the year, while a unit with three weeks of maintenance is unavailable for two periods during the year. If the week to begin maintenance is not specified, ICARUS schedules maintenance on the unit to minimize the effect on the system's expected capacity.

The ICARUS module uses the expected reserve margin (ERM) to evaluate the effect of the maintenance schedule on the system. Although the ERM can reasonably predict the reliability of the generating system, it does not consider costs. The ERM is calculated as follows:

$$\text{ERM} = (\text{expected system capacity} - \text{peak load})/\text{peak load}. \tag{8.2}$$

The expected system capacity includes the capacity from firm purchases or sales and the contribution from the fixed energy technology (e.g., hydropower). The expected system capacity is calculated by summing, over all units, the rated capacity of the unit, times one, minus the forced outage rate.

All three methods for scheduling maintenance were used for the power marketing EIS. The method used for a particular utility depends on the characteristics of the utility system and the information available. In general, all data supplied by the utility systems are input into PACE, including the specific maintenance dates and annual variations (i.e., maintenance cycles). When specific maintenance information is not available, generic scheduled outage lengths from the Electric Power Research Institute's (EPRI's) Generator Availability Data Set (GADS) (North American Electric Reliability Council 1991) are used, and ICARUS schedules the downtime.

Because ICARUS was run for 26 periods per year, the duration of the scheduled outages and the timing of the outages did not always match the data supplied by the utilities. For example, a unit scheduled for maintenance beginning January 8 was modeled in ICARUS as being scheduled for maintenance on either January 1 (ICARUS time period 1) or January 15 (ICARUS time period 2). The approximate dates for each ICARUS time period are shown in Table 22. ICARUS also assumes that units are down for an entire period. If a unit is scheduled to have a downtime lasting an odd number of weeks (i.e., three weeks), annual maintenance lengths are varied from year to year such that in one year the maintenance schedule is one week too long, and in the next year the maintenance schedule is one week too short. Thus, the average maintenance length over the study period matches the average length specified by a utility.

TABLE 22 Biweekly Periods Used for ICARUS Utility Dispatch

Season	ICARUS Period	Beginning Date	Ending Date
Winter	1	January 1	January 14
	2[a]	January 15	January 28
	3	January 29	February 11
	4[a]	February 12	February 25
	5	February 26	March 11
	6[a]	March 12	March 25
Summer	7	March 26	April 8
	8[a]	April 9	April 22
	9	April 23	May 6
	10[a]	May 7	May 20
	11	May 21	June 3
	12	June 4	June 17
	13[a]	June 18	July 1
	14	July 2	July 15
	15[a]	July 16	July 29
	16	July 30	August 12
	17[a]	August 13	August 26
	18	August 27	September 9
	19[a]	September 10	September 23
Winter	20	September 24	October 7
	21[a]	October 8	October 21
	22	October 22	November 4
	23	November 5	November 18
	24[a]	November 19	December 2
	25	December 3	December 16
	26[a]	December 17	December 30

[a] Spot market and power plant operations were simulated for seven days during these periods. See Sections 6 and 10 for more details.

8.2.4 Production-Cost Calculations

The ICARUS module estimates the operations of electric utility systems through the use of a probabilistic simulation approach that determined the capacity factor for each block of each unit. It uses detailed unit and system data to determine period and annual energy generation and the costs associated with each generating unit and the entire generating system.

The principles underlying the ICARUS generating unit dispatching logic are based on a technique referred to as the Baleriaux-Booth method (Baleriaux, Jamoulle, and Linard de Guertechin 1967; Booth 1972). This approach represents the outage capacity from unit failures as though it were equivalent to additional loads that must be served by other units. The resulting equivalent load duration curve (ELDC) portrays the original system loads together with probabilistically determined outage capacities.

A sequence of ELDCs is constructed by dispatching each unit to determine its generation. Each unit is convolved into the load duration curve to determine the net effect of its forced outages on the equivalent loads. Each successive ELDC consists of a weighted average between the previous load curve and the same load curve displaced by the capacity (in megawatts) of the unit being dispatched. When utility contacts did not supply unit-level data for forced outages, generic data from EPRI's GADS were used.

The ELDC method estimates system reliability parameters. Once all generating units are fully convolved into the load curve, the final ELDC portrays the characteristics necessary for calculating loss-of-load probability (LOLP), expected unserved energy (EUE), and loss-of-energy probability (LOEP). For period-by-period reliability calculations, units on scheduled maintenance for a particular period are not included in the dispatching or reliability calculations for that period.

Once the unit's generation level is determined, fuel use, fuel costs, and variable O&M costs can be calculated for each unit. Final results are aggregated over all fuel types and for the entire generating system.

8.2.5 Emergency Interties

Many utilities in the SLCA power marketing area have agreements with neighboring utilities to provide energy if a severe power outage occurs. The Emergency Interties Variable input to ICARUS allows users to specify the level of emergency interties available throughout the year.

8.2.6 Thermal Unit Loading Order

In ICARUS, the thermal unit loading is specified in three ways: (1) it is defined by the user; (2) it is calculated on the basis of economic considerations; or (3) it is calculated on the basis of spinning reserve considerations.

In option 1, a loading order number is assigned to each block of each unit. The units are then loaded in ascending loading order number. This option is used when the system is small or when special system operating constraints must be represented.

Option 2 is calculated within ICARUS. The model calculates a loading order number for each block of each unit on the basis of the unit's heat rate, fuel cost, and variable O&M cost. As in the user-defined option, after the loading order numbers are assigned, the system loads the units in ascending loading order number. This representation produces the lowest operating costs for the system and, when spinning reserve requirements are low, typically results in a loading order that has a unit's peak block of capacity loaded immediately after its base block.

When utility contacts did not supply unit-level data, information from public data services sources was used. Unit heat rates were computed on the basis of fuel consumption and net generation contained in the Energy Information Administration's (EIA's) *Steam-Electric Plant Operation and Design Report* and on heat rate data contained in EIA's *Annual Electric Generator Report*. Plant-level fuel costs by fuel type were obtained in the Federal Energy Regulatory Commission's *Monthly Report of Cost and Utility of Fuels for Electric Plants*. To minimize problems caused by anomalous data, average values over a 3- to 5-year period were computed. Fuel prices were adjusted by the gross national product deflator. Generic data from EPRI's regional system database were also used for both fixed and variable O&M costs when more specific utility-supplied data were available (EPRI 1989).

Although option 2 produces the lowest operating costs, this representation fails to account for various system constraints. For example, most units have "ramp rates" that limit the rate at which capacity can be added. Transmission constraints also can limit the response of units in some locations to loads in other locations. Finally, a utility may have a policy concerning the required amount of available fast spinning reserve. These considerations and other operating constraints interfere with the pure economic loading order. To represent these constraints, ICARUS uses a spinning reserve constraint to perturb the option 1 (user-defined) and option 2 (economic) loading orders. The system spinning reserve goal is specified in the following form:

$$\text{Goal} = [\text{SPNMLT} \times \text{capacity of the largest unit on line (other than hydropower)}] + [\text{SFRACT} \times \text{period peak}] + \text{SMW}, \qquad (8.3)$$

where SPNMLT and SFRACT are multipliers, SMW is a constant, and any of these parameters can be zero. The spinning reserve contribution (as a percentage) is the fast spinning reserve available from the total unit. In addition, this percentage multiplied by the total unit capacity should be less than or equal to the capacity in the second block. This parameter is usually defined for units with more than one block. A unit is assumed to contribute to spinning reserve only when it is loaded at a capacity level equal to its first block.

8.2.7 Loading Order of Limited Energy Sources

ICARUS represents energy-limited energy sources such as hydropower stations and contracts with a maximum energy constraint. As with thermal units, energy-limited sources are represented by two blocks — base and peak. The capacity of the base and peak blocks, and the capacity factor for the peak block, is specified for each of the 26 demand periods. The base block of the energy limited source is assumed to generate at full load throughout the year. This block represents a minimum flow requirement from a pondage hydropower plant or a minimum schedule requirement of an LTF contract. The peak portion is loaded to meet the specified energy generation in the period.

8.3 SIMULATING LONG-TERM FIRM CONTRACTS

Both existing and new LTF capacity and energy contracts between utilities are taken into account when simulating utility dispatch and supply-side expansion. The simulation method used depends on the contract type and information provided by utility contacts. The methods presented below were tailored to best represent the unique terms and conditions of a specific contract.

The PACE system uses several methodologies for estimating LTF contractual obligations between utility systems: (1) hourly load modifications, (2) thermal unit representation, (3) limited energy source representation, and (4) LDC modifications.

When a contract between large systems expires, capacity and energy specified in the contract are no longer available to the purchaser, thus decreasing its supply. In PACE, the expiration of an LTF contract, therefore, is treated as a resource retirement to the purchaser, and the seller has additional capacity and energy made available to its system. Contracts between a buyer and seller are not renewed regardless of load and economic circumstances. For all alternatives, this assumption tends to overestimate utility costs if (1) the seller has excess capacity for a substantial time after the contract expires and (2) the contract is economical for the buyer and seller. However, this overestimate is reduced through spot market sales. If it is economical, the electricity generated from the excess capacity is sold on the spot market (Section 9).

8.3.1 Modifying Hourly Load Forecasts for Long-Term Firm Contracts

The PACE modeling system uses three different load modification methods for representing LTF contractual obligations between utility systems: (1) explicitly scheduling hourly transactions, (2) making transactions based on the purchaser's load pattern, and (3) maximizing reductions in peak loads.

Hourly loads are reduced for the buyer of LTF energy. Hourly sales transaction are then added to the loads of the seller. Depending on the situation, line losses are accounted for by increasing the energy supplied by the seller via a line loss factor.

8.3.1.1 Specifying Hourly Transactions

The PACE system can modify hourly load forecasts based on user-supplied purchases and sales information. The user enters a purchase or sale pattern for a 24-h period (one day). This hourly pattern is then applied to the load forecast for specific days (e.g., Monday, Wednesday, and Thursday) and for specific times (e.g., January through April from 1994 through 2006). Purchases for the specified hours are subtracted from the load forecast, and sales are added to the load forecast. To properly represent some contracts, the user specifies several hourly load patterns. For example, one pattern can be used to represent weekday transactions, a second pattern can be used to represent transactions on Saturday, and a third pattern can be used to represent transactions on Sunday.

When the LTF contract is contingent on operating a specific unit or a group of units, the hourly load pattern is altered to reflect scheduled outages. Hourly transactions are reduced proportional to scheduled outages of the contingent unit. For example, if a contract is contingent on the operation of two 500-MW units, hourly transactions are curtailed by 50% when one of the units is scheduled for maintenance. The user must specify timing of scheduled outages. If the utility does not supply maintenance schedules, a preliminary run of ICARUS projects when the scheduled outage would occur (Section 5.3).

8.3.1.2 Making Transactions on the Basis of the Purchaser's Load Pattern

A second method for representing purchases by altering hourly loads is based on the buyer's hourly load pattern and on the monthly capacity and energy limits specified in a contract. Average hourly load patterns are computed for a weekday and a weekend day. The average weekday load pattern determines hourly purchase quantities for weekdays in a month, while the weekend load pattern determines hourly purchases for all weekend days in a month. Once an average load pattern has been calculated for historic loads, purchases are patterned such that the maximum allowable amount of energy is purchased at the hour of peak demand, and proportionally less energy is purchased at other times. For example, 100 MW (the contracted capacity) is purchased at 4 p.m., when the demand is 1,000 MW (peak load). Only 50 MW is purchased at 1 a.m. when the demand is 500 MW. If the summation of the hourly purchases does not match the monthly contract energy total, purchases in all hours except the peak are adjusted. These adjustments increase or decrease hourly purchases such that the total monthly contract energy amount is purchased. Hourly purchase adjustments are proportional to the difference between the peak load and the load in any specific hour. Therefore, adjustments for off-peak hours are much larger than adjustments for on-peak hours.

8.3.1.3 Maximizing Reductions in Peak Load

The third method for representing purchases by adjusting hourly loads is use of a load reduction algorithm. This algorithm was written by the Environmental Defense Fund (EDF) to simulate hydropower plant operations and modified by ANL for use in the power marketing EIS. The algorithm simulates hourly purchase transactions such that the maximum load on supply-side resources of the buyer is minimized. The algorithm accounts for the schedulers' total monthly firm energy, maximum capacity, a minimum schedule requirement, and a maximum hourly change in loads. This algorithm also assumes that purchases cannot be used to replace lost capacity/energy from a unit that has an unscheduled outage. Peak loads are minimized over a time frame specified by the user (i.e., a day, week, month, or season). The algorithm is best suited to represent LTF contracts that are noncontingent, have energy limits, are inexpensive compared with other energy supply sources in the buyer's system, or have a take-or-pay contract clause.

The load reduction algorithm modifies loads in each hour of the study period. These restrictions account for loads that will be served by LTF purchases from Western area offices, including those of Salt Lake City, Loveland, and Phoenix. The algorithm was run on a monthly basis (i.e., to minimize monthly peaks) from 1993 through 2012. The hourly load amounts that are reduced to simulate SLCA firm contracts are used in the Hydro LP module (Section 6.3.1.1).

8.3.2 Representing a Contract with a Unit

The ICARUS module can also represent LTF contracts by a thermal unit or a unit with a limited energy supply. The representation used for the power marketing EIS depends on the terms of the contract and availability of data.

8.3.2.1 Thermal Unit Representation

An LTF contract is represented in ICARUS as a thermal unit if the contract has a specified capacity limit, has no energy limits, and has a well-defined energy charge. The capacity of the unit that represents the contract is set to the capacity specified in the LTF contract. When the contract specifies a minimum schedule requirement, the unit is split into two blocks. The capacity of the first block is set to the minimum schedule requirement and is the first thermal unit loaded into the LDC. The base block of the thermal unit is loaded into the LDC before any thermal blocks. The remaining contract capacity is assigned to the second block and represents the discretionary portion of the contract.

Variable O&M costs for the contract unit represent energy charges, and fixed O&M costs represent demand charges. Contract-specified demand charges, energy charges, and capacity levels are modified over time to reflect changes in contract terms. Because the periods in the ICARUS module were set to 26 for this analysis, changes in contract terms within a year could only be made at the beginning of the two-week periods shown in Table 21. Changes in contract terms between years were not limited.

The energy purchased under an LTF contract is estimated in ICARUS by loading the contract unit into period LDCs. That is, the energy purchased under the contract equals the generation computed for the thermal unit. Except for the block that represents the minimum schedule requirement, blocks representing a contract are loaded into an LDC according to its economic loading order (i.e., contract energy price).

If the contract is contingent on the operational status of one or more of the supplier's generating units, the availability of the contract unit is assigned such that it adequately reflects the outages of the contingent units. When the contingent unit specified in the contract is off-line because of a scheduled or an unscheduled outage, the seller is not obligated to supply energy to the buyer. If the contract is contingent on only one unit and that unit is shut down for maintenance, the contract is halted until the unit is back on-line. If the contract depends on more than one unit, the contract's capacity is lowered by applying a derating factor. This factor equals the capacity of units shut down for maintenance in a two-week period relative to the capacity of all the contingent units. The seller determines the timing of scheduled outages. Curtailments due to random outages are estimated by assigning a forced outage rate to the thermal unit. The outage rate equals the weighted (by unit capacities) average forced outage rate of all contingent units that are not on scheduled maintenance. The contingent unit (or a portion of the unit) is included in the buyer's unit inventory until the contract expiration date.

8.3.2.2 Limited Energy Source Representation

If a contract limits the energy sold in a given time frame, the contract can be represented by a unit that has a limited energy source. The base block of a limited energy source unit represents a minimum schedule requirement. The remainder of the contracted capacity is assigned to the second block of the unit and represents the discretionary portion of the contract. Energy purchases for this block are derived from contract terms and are equal to the energy that is not consumed by minimum schedule requirements.

When using a limited energy source for representing contracts, unit operational contingencies are modeled in a similar manner as when modeling a contract as a thermal unit. That is, the contract is curtailed or halted when contingent units are shut down for maintenance. The capacity and energy of the fixed energy unit are derated instead of assigning a forced outage rate to the unit.

The base block of the limited energy source is the first block loaded into the LDC. The second block is loaded into the LDC such that it exactly matches the energy assigned to that block. In most situations, a thermal block must be split into two pieces in order to match the targeted energy of the second block of the fixed energy unit.

8.3.3 Modifying Load Duration Curves for Long-Term Firm Purchases and Sales

When incomplete data are available to represent LTF contracts by any one of the above methods, ICARUS accounts for purchase and sales activities by adjusting the LDC. To represent a firm purchase or sale, the following input data are required: (1) the number of days per week the transfer is available, (2) the number of hours per day the transfer is available, (3) the transfer capacity available for each period, and (4) the degree to which the firm transfer occurs at times of highest demand, or EXTENT.

On the basis of user-supplied data, ICARUS constructs a load correlation curve (LCC), subject to the following criteria:

- The correlation at peak demand is 100%.
- The energy associated with firm purchases or sales is the capacity of firm purchases or sales multiplied by the time during which firm purchases or sales are in effect.
- The correlation curve is linear.

For example, suppose that firm purchases and sales are contracted for eight hours per day and for seven days per week, or for one-third of the total time. The LCC could take several forms, depending of the value of EXTENT. When EXTENT is close to 1.0, the correlation is nearly perfect; that is, power is transferred only at times of highest demand. When EXTENT is near zero, the correlation between the energy transfer and the times of highest loads is much less, but still positive. The height at minimum load is determined such that the area under the curve equals the fraction of time that firm purchases or sales are in effect.

Firm purchases and sales are considered noncontingent. In other words, the energy of firm purchases is always available, and the energy of firm sales is always sold. However, if demand is lower than the firm purchases, the full amount of firm purchases is not used. The economic calculations assume that none of the unserved demand coincides with firm sales.

8.4 HYDROPOWER REPRESENTATION

The PACE system is also used to simulate three different types of hydropower units: (1) run-of-river, (2) pondage, and (3) pumped storage. For each of these hydropower types, PACE has at least two different methods of representation.

8.4.1 Run-of-River Units

Run-of-river hydropower units are simulated by either altering hourly loads or introducing a representative unit into the inventory. Typically, loads are altered by the load-shaving algorithm. The total energy reduced by the algorithm is equal to the electricity produced by the hydropower plant for a specified time (i.e., a month). The minimum generation level (i.e., minimum schedule requirement) input into the load-shaving algorithm is set to the average energy produced by the run-of-river unit in a 1-hour time period (i.e., total generation/number hours in the period). Therefore, all the energy is consumed by the minimum generation requirement, and loads in all hours are reduced by an equal amount.

A run-of-river hydropower unit can be represented in the ICARUS module as a thermal unit or as a limited energy unit. In either case, the capacity of the unit is determined by the average energy generated by the unit in a specified time, and the unit is loaded under the base load portion of the LDC. If the hydropower plant is represented by a thermal unit, a forced outage rate can be assigned to the unit. When typical monthly energy production from run-of-river hydro was not supplied by utility contact, average historical values were computed from the EIA's monthly power report.

8.4.2 Pondage Units

The PACE system has three different methods for representing pondage hydropower units. The first method is a detailed representation of one or more hydropower units that are integrated with other supply sources. This representation simulates SLCA/IP hydropower dispatch and is explained in detail in Section 6.3.1.3. The second method uses the load reduction algorithm, and the third uses an energy-limited source unit.

Typically, loads are altered by the load reduction algorithm. The total energy reduced by the algorithm is equal to the electricity produced by the hydropower plant in a specified period (i.e., a month). The minimum generation level input into the load reduction algorithm is set equal to the instantaneous generation in terms of megawatts produced by a minimum flow requirement (if any). Loads in all hours are reduced equally by the minimum flow requirement. The algorithm uses any capacity and energy remaining after subtracting the minimum release requirements to minimize the peak load. For this analysis, capacity and energy for pondage hydropower units varied on a monthly basis.

The third method used to represent pondage hydropower is through an energy-limited source in the ICARUS module. The energy-limited source is represented by two blocks: base and peak. The base block of the energy-limited source is assumed to generate at full load throughout the year. This block represents a minimum flow requirement from the pondage hydropower unit. The peak block is loaded to meet the specified energy demand in the period. For the power marketing EIS, 26 biweekly periods were simulated. When the unit is represented as an energy-limited source, some of the energy reserved for the peak block is used to replace "lost" generation from units that were out of service because of a forced outage.

8.4.3 Pumped Storage Units

Pumped storage units are modeled by PACE in two separate stages. In the first stage, loads are increased during off-peak hours to represent pumping. The release of the stored energy is simulated in the second stage. As with a pondage unit, this second stage can be represented by either load modifications or an energy-limited source. The energy pumped and released during each period is based on historical operations of the pumped storage facility and pumping losses.

8.5 SALT RIVER PROJECT INTERCHANGE AGREEMENT CURTAILMENTS

The Salt River Project has partial ownership in several generating units outside Arizona, far from its service territory. These include units located in northern Colorado (Craig-1 and -2 and Hayden-2) and in northwestern New Mexico (units 4 and 5 of the Four Corners plant). To get the energy generated from these units to SRP's load centers, SRP entered into an exchange agreement with Reclamation in 1962. The agreement provides primarily for an exchange of capacity and energy between SRP's entitlement in the coal-fired generating units at Craig, Hayden, and Four Corners for generation at the Glen Canyon power plant. The contract, which was amended in 1974, is now between SRP and Western.

When the exchange is in effect, a portion of the generation from the Glen Canyon power plant is delivered to SRP at Pinnacle Peak (near Phoenix). In exchange, generation from Craig and Hayden serves Western's loads in Colorado, Utah and Wyoming, and generation from Four Corners serves Western's loads in New Mexico. Generation is exchanged on a kilowatt-hour for kilowatt-hour basis.

During off-peak periods when generation from Glen Canyon is low, the Glen Canyon-Shiprock 230-kV line is used to wheel power for SRP from Craig, Hayden and Four Corners in the north to Pinnacle Peak in the south. During on-peak periods, when Glen Canyon generation is high, SRP energy is displaced and used by Western in the north. Salt River then receives Glen Canyon generation in the south, and the Glen Canyon-Shiprock line is not scheduled with SRP energy.

The exchange is curtailed and in some situations completely halted when (1) Western is not generating adequate energy at Glen Canyon; (2) SRP is not generating at its coal-fired units; (3) Western does not have sufficient load to use the coal-fired generation; or (4) Western does not have sufficient transmission capacity between SRP generation in the north and Glen Canyon. Both commitment-level alternative and operational scenario are expected to affect the frequency and magnitude of these curtailments. Therefore, the dispatch of SRP's other generating resources is also affected. On the basis of the curtailments, SRP will also have to adjust its capacity expansion plans. For a detailed discussion of Western's transmission system, as it relates to the SRP interchange agreement, see Veselka et al. (1995).

8.5.1 Estimating Unit Dispatch

Delivery curtailments of energy from northern plants in Colorado and southern plants in New Mexico affect the operations of most SRP units. To accurately capture these effects, ANL used northern and southern curtailment distributions to estimate additional loads that would be faced by other units in SRP's systems. That is, because of curtailments, other more expensive units in the system will have to operate at a higher level and more frequently to replace reduced generation from Craig, Hayden, and Four Corners. Both the magnitude and frequency of these curtailments are important when determining system operations. Therefore, ANL used curtailment distributions supplied by Western to estimate additional loads that SRP units with higher operating costs will experience because of curtailments. Distributions were supplied for both summer and winter for all 12 combinations of commitment-level alternatives and operational scenarios. The effect of curtailments on unit dispatch was achieved by convolving the northern and southern curtailment distributions with SRP's initial LDCs.

Two convolutions were performed for each biweekly period — one for the northern units and one for the southern units. Table 22 defines the biweekly periods and shows how the biweekly periods relate to the winter and summer seasons. For each convolution, the load added to the LDC is equal to the area under the curtailment distribution curve. A sample curtailment distribution for the summer season is provided in Table 23.

Curtailment distributions were adjusted for maintenance schedules. When a northern or southern unit is shut down for maintenance, the curtailment distribution is proportionally reduced. Once biweekly load duration curves have been adjusted, the ICARUS model estimates block-level capacity factors. Because curtailment distributions are based on

TABLE 23 Salt River Project Summer Curtailment Distribution for the No Action Alternative for the High-Flexibility Scenario

	North		South		North and South Combined	
Curtailment Exceedance Probability (%)	Capacity Curtailed (MW)	Biweekly Energy Curtailed[a] (MWh)	Capacity Curtailed (MW)	Biweekly Energy Curtailed[a] (MWh)	Capacity Curtailed (MW)	Biweekly Energy Curtailed[a] (MWh)
0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0
25	0.0	0.0	0.0	0.0	0.0	0.0
30	0.0	0.0	0.0	0.0	0.0	0.0
35	0.0	0.0	0.0	0.0	0.0	0.0
40	0.0	0.0	0.0	0.0	0.0	0.0
45	0.0	0.0	0.0	0.0	0.0	0.0
50	0.0	0.0	0.0	0.0	0.0	0.0
55	0.0	0.0	0.0	0.0	0.0	0.0
60	0.0	0.0	0.0	0.0	0.0	0.0
65	0.0	0.0	0.0	0.0	0.0	0.0
70	0.0	0.0	0.0	0.0	0.0	0.0
75	0.0	0.0	0.0	0.0	0.0	0.0
80	10.3	173.5	0.0	0.0	10.3	173.5
85	33.4	562.7	0.0	0.0	33.4	562.7
90	49.1	827.1	0.0	0.0	49.1	827.1
95	62.3	1,049.5	0.0	0.0	62.3	1,049.5
100	81.0	1,364.5	16.9	284.7	97.9	1,649.2
Total		3,977.4		284.7		4,262.1

[a] Biweekly energy curtailment equals the capacity curtailed times 0.05 times 8,760 hours in a year divided by 26 biweekly periods in a year.

the operation of northern and southern units, it is important that these units do not serve any loads due to the units' own curtailments. Therefore, units at Craig, Hayden, and Four Corners are represented in ICARUS as one block. Because these units are lower cost units in the SRP system, they "naturally" fall under the base load portion of the adjusted load duration curve and do not serve loads that result from the curtailment convolution process. Therefore, capacity factor results for these units from ICARUS equal the unit's availability (i.e., [1.0 – scheduled outage rate] × equivalent forced outage rate]). The initial estimates given by ICARUS of generation and total operating costs for these units are too high because curtailments are not considered. Therefore, biweekly generation and total cost estimates from ICARUS are reduced by applying the following adjustment factor:

$$gen_i = [\ \sum igen_i - \sum(curtp_{jklmn} \times curtl_{jklmn}) \times hours] / \sum igen_i\ , \tag{8.4}$$

where

gen_i	=	adjusted generation at unit i (MWh);
$igen_i$	=	ICARUS generation estimate at unit i (MWh);
$curtp_{jklmn}$	=	probability of curtailment at point j on the probability distribution curve for marketing alternative k, hydropower operational condition l, and hydropower condition m in season n (fraction);
$curtl_{jklmn}$	=	level of curtailment at point j on the probability distribution curve for marketing alternative k; hydropower operational condition l, and hydropower condition m in season n (MW); and
hours	=	number of hours in the biweekly period (i.e., 336).

8.5.2 Estimating Capacity Expansion Requirements

As described in Section 7.1, capacity expansion requirements are based on peak loads, existing and committed generating capacity, LTF contractual commitments, and a reserve margin. Because of curtailments of energy deliveries from northern generating resources to SRP's load, the total capacity entitlement of the Craig, Hayden, and Four Corners plants was not used in the reserve margin calculation. Instead, the capacity of these units was adjusted to reflect curtailments of the interchange agreement.

Capacity adjustments were made by using a probability distribution of projected curtailments. Curtailment distributions consist of a set of values that represent the probability that capacity will not be available to satisfy SRP's loads. Curtailment probabilities were determined for 20 points along the probability distribution curve (i.e., intervals of 5 percentile). The capacity used in the reserve margin calculation is based on the 90% capacity exceedance level (i.e., capacity will be curtailed by a greater amount only

10% of the time) during the summer months (i.e., SRP's peak load season). Separate curtailment distributions were used for the Colorado plants (northern distribution) and for the Four Corners plant (southern distribution). Curtailment distributions vary by commitment-level alternative, operational scenario, and hydropower condition. When adjusting capacity amounts for computing a reserve margin, average SCLA/IP hydropower conditions were used.

The method used in this analysis overestimates the effects of commitment-level alternatives and operational scenarios on SRP. This overestimate occurs because energy that is curtailed because the interchange is not working can be sold on the spot market to utilities in Colorado and Wyoming.

9 EFFECTS OF COMMITMENT-LEVEL ALTERNATIVES ON CAPACITY EXPANSION PATHS

Least-cost capacity expansion paths were determined for both the large Western customers and for investor-owned utility systems. Optimal expansion paths and related production costs for large Western customers varied by commitment-level alternative and operational scenario. However, because the investor-owned systems do not receive SLCA LTF capacity and energy, it was assumed that capacity expansion paths for these systems would not be affected by commitment-level alternatives. Results relating to the large Western customers are discussed in Section 9.1, and results for the investor-owned utilities are addressed in Section 9.2.

Although the SLCA contract period is 15 years, optimal capacity expansion paths were determined for 20 years. Power system analysts simulated an additional five years to reduce the end effects associated with the PACE capacity expansion module. Although simulations were carried out for 20 years, only the first 15 simulated years are reported in this section. Costs for the 5-year extension are reported in Section 11. However, these estimates are only an approximation, and less confidence relative to the first 15 years should be placed on these estimates.

Capacity expansion requirements for both large Western customers and investor-owned utility systems were determined twice. Data and modeling results, including estimates of long- and short-run marginal costs and hourly load forecasts from an initial capacity expansion analysis, were supplied to financial analysts and DSM modelers (Cavallo et al. 1995). On the basis of this information, DSM modelers generated new hourly load forecasts (one for each utility system) and supplied them to power system analysts. Loads were revised on the basis of DSM programs projected to be in place. The revised loads were then used to determine a second set of capacity expansion paths. Identical DSM options were used for all the alternatives. This procedure was used because the results of the DSM analysis showed that each alternative and operational scenario had very little or no impact on DSM programs and, therefore, on hourly loads. More detailed information regarding the effect of marketing alternatives and operational scenarios on electricity demand is provided in Chapter 4 of Cavallo et al. (1995).

9.1 SLCA CUSTOMERS' EXPANSION PATHS

Because the LTF capacity and energy that a system purchases from Western affect how a utility's generating resources are dispatched and its energy purchasing patterns, distinct expansion paths emerge as marketing criteria are altered. Specifically, for each of the affected utility systems, the lower the capacity and energy allocation, the larger the capacity additions required. On one extreme is the No Action Alternative, where customers receive relatively large amounts of both capacity and energy. On the other extreme is Alternative 4, where both capacity and energy allocations are relatively low. The other two alternatives fall between these two extreme conditions.

Effects of the commitment-level alternatives on system expansion were analyzed from four perspectives: (1) total megawatts of capacity expansion requirements, (2) technology types selected in optimal expansion paths, (3) unit size selected in optimal expansion paths, and (4) expansion costs (Section 11).

Several important assumptions were made when estimating capacity expansion paths and related costs. It was assumed that large customers would enter into LTF purchase agreements with Western regardless of the capacity and energy charges and contract terms. As shown in Table 41, Western charge rates are projected to be significantly higher (more than twice the 1992 charge rates) under certain combinations of commitment-level alternative and operational scenario. It was also assumed that a customer would purchase 100% of its energy allocation in each month. These assumptions tend to overestimate the cost impacts of commitment-level alternatives. That is, in certain utility systems, other supply-side options may be more economical than entering into an LTF contract with Western. Also, other utility systems that do not currently receive Western allocations may benefit from entering into a Western LTF contract at the highest SLCA charge rate. These assumptions were made because it was beyond the scope and resources of this analysis to optimally distribute energy and capacity allocations among all potential utility customers (both current and new). However, the assumptions regarding the acceptance of LTF contracts regardless of price and contract terms tend to overestimate the cost of commitment-level alternatives relative to the No Action Alternative.

Except for one system that has a very flexible contract, it was also assumed that a LTF contract between a large customer and another utility system would not be altered or terminated because of changes in SLCA LTF contracts. This assumption would also overestimate costs. The optimal solution would alter contracts such that an overall least-cost solution among the systems would be obtained.

Capacity expansion paths for each system are determined in isolation. However, often it is cost beneficial for two or more utility systems to take advantage of economies of scale and jointly construct a unit. This assumption of isolation tends to overestimate costs under both the No Action Alternative and the other commitment-level alternatives. It also tends to overestimate differences between commitment-level alternatives, in that incremental capacity additions above the No Action Alternative tend to be smaller and less efficient than additions that take full advantage of joint ownership opportunities.

9.1.1 Capacity Expansion Requirements

Capacity expansion requirements refer to the timing and magnitude of capacity additions required for a system to reliably satisfy future projected loads. Expansion requirements for each individual utility system were estimated by Equation 7.1. Table 24 presents the aggregate capacity expansion paths for the large Western customers as a function of commitment-level alternative for the high-flexibility scenario. In general, the lower amounts of capacity and energy purchased from Western, the sooner systems need to add capacity.

TABLE 24 Comparison of the Effects of Commitment-Level Alternatives on Capacity Additions for the 12 Large Western Customers for the High-Flexibility Scenario[a]

	Cumulative Capacity Expansion Additions (MW)[b]				Capacity Difference from the No Action Alternative (MW)		
Projection Year	No Action	Alt. 2	Alt. 5	Alt. 4	Alt. 2	Alt. 5	Alt. 4
1993	0.0	0.0	0.0	40.0	0.0	0.0	40.0
1994	140.2	406.9	529.7	639.3	266.7	389.5	499.1
1995	215.4	479.9	602.7	777.8	264.5	387.3	562.4
1996	361.4	665.9	898.7	1,073.8	304.5	537.3	712.4
1997	677.4	908.9	1,080.6	1,256.5	231.5	403.2	579.1
1998	677.4	922.6	1,090.6	1,321.5	245.1	413.2	644.1
1999	977.4	1,222.6	1,463.3	1,621.5	245.2	485.9	644.1
2000	997.4	1,242.6	1,483.3	1,649.2	245.2	485.9	651.8
2001	1,174.7	1,367.5	1,709.5	1,813.1	192.8	534.8	638.4
2002	1,623.6	1,816.4	2,192.5	2,213.1	192.8	568.9	589.5
2003	1,712.7	1,905.5	2,271.7	2,358.6	192.8	559.0	645.9
2004	1,715.6	1,905.5	2,580.5	2,681.1	189.9	864.9	965.5
2005	1,948.6	2,559.8	2,598.2	2,714.3	611.2	649.6	765.7
2006	2,517.3	2,603.0	3,161.0	3,277.1	85.7	643.7	759.8
2007	2,541.9	2,754.7	3,339.4	3,432.0	212.8	797.5	890.1
Increase above No Action (%)	0.0	8.3	31.3	35.0			
Average annual capacity added (MW)	169.5	183.6	222.6	228.8			
Average difference (MW)					174.0	386.0	479.4

[a] See Table 2 for a list of the large systems.

[b] This analysis assumed that Western customers were given sufficient time to plan capacity additions before 1993 and that technologies such as gas turbines could be on-line early in the study period. Some capacity additions also reflect a change in capacity contracts.

The No Action Alternative results in fewer additions to capacity, followed by Alternative 2, 5, and then 4. On an average annual basis, Alternative 2 added about 8% more capacity than the No Action Alternative, Alternative 5 about 31% more, and Alternative 4 about 35% more. The capacity expansion is equivalent to an average yearly capacity addition of 170, 184, 223, and 229 MW for the No Action Alternative and Alternatives 2, 5, and 4, respectively.

Table 25 shows that for the 12 large Western customers (1) Alternative 2 has 137 MW more LTF capacity than the No Action Alternative; (2) Alternative 5 has 565 MW less than the No Action Alternative; and (3) Alternative 4 has 629 MW less than the No Action Alternative. Since SLCA LTF capacity is noncontingent, in addition to the reductions in LTF capacity, a reserve margin must be taken into account when estimating capacity additions. Minimum reserve margins for this analysis ranged from 15 to 20%. This reserve margin is taken into consideration during the search for the optimal expansion path and ensures that the final capacity added will be greater than the loss of SLCA capacity by at least 15-20%.

TABLE 25 SLCA Long-Term Firm Capacity and Energy for the 12 Large Western Customers

	Alternative			
LTF Characteristic	No Action	2	5	4
Summer CROD (MW)	1,009	1,236	534	470
Annual energy allocation (GWh)	5,047	2,823	4,687	2,823
Annual load factor (%)	51	26	100	68
Minimum schedule requirement (%)	35	10	100	52
Minimum schedule requirement (MWh per hour)	385	124	476	244
Capacity decrease from the No Action Alternative (MW)	0	-137[a]	565[a]	629[a]
Capacity decrease from the No Action Alternative (%)	0	-11[a]	51[a]	57[a]
Energy decrease from the No Action Alternative (GWh)	0	2,224	360	2,224
Energy decrease from the No Action Alternative (%)	0	44	7	44

[a] Differences displayed are for the summer. Differences in the winter are 35 MW (or about 3%) higher.

Capacity expansion differences from the No Action Alternative (Table 24) are directly related to decreases in SLCA capacity and energy under commitment-level alternatives. As stated earlier, this result follows the logic that the lesser the allocation, the greater the capacity added by the system. However, when comparing the cumulative differences among capacity expansion plans in Table 24 with the capacity differences in Table 25, for Alternative 2 more capacity is built than under the No Action Alternative. More capacity was built despite an increased LTF capacity sales of 137 MW. This result occurs because the energy available for use at peak times (i.e., discretionary energy) is insufficient to effectively use the peaking capacity on a daily basis. In other words, the capacity potential cannot always be reached during the system's daily peak demand periods because the corresponding amount of discretionary energy prohibits such a possibility. For Alternative 2, the annual load factor is 26%, and more than 38% of the 2,823 GWh of LTF energy is needed to satisfy minimum schedule requirements (Table 9). At this level of load factor and minimum schedule requirement, the usable LTF capacity varies widely among utility systems and by the month of the year. Some systems can utilize all of the LTF capacity and require less capacity additions than under the No Action Alternative. At the other extreme, one utility system cannot effectively utilize more than 40% of its LTF capacity allocation and must build more capacity than under the No Action Alternative.

Under Alternatives 4 and 5, significantly less additional capacity is constructed in the early forecast period (i.e., up to 1998) than is needed to compensate for the loss in SLCA LTF capacity purchases. Less capacity is constructed because many of the large customers currently have excess capacity and, in the short term, can "absorb" lower SLCA capacity purchases without acquiring additional capacity (i.e., building new units or purchasing capacity). However, in the long term, additional capacity in excess of the No Action Alternative must be constructed to compensate for much of the SLCA capacity loss. In more than one utility system, the full SLCA LTF capacity loss is not realized until after 2007 (i.e., the end of the study period).

Because new units are added in increments of standard sizes, capacity expansion usually exceeds the target minimum reserve margin. This level is surpassed by as much as the size of the largest candidate technology for capacity expansion. The result is a "lumpy" capacity expansion plan in which large increments of capacity are added in anticipation of future load growth. Because, on a per-megawatt basis, it is cheaper to build large units than to build small units, it is usually not cost-effective for a utility system to exactly match its capacity expansion requirements in every year. Instead, utility systems "overbuild" in a year and have excess capacity for a time until supply and demand are in equilibrium. This phenomenon results in significant year-to-year variations in capacity differences between the No Action Alternative and Alternatives 2, 4, and 5.

9.1.2 Effects on the Selection of Technology Type

Western's power marketing criteria affect loads that a utility system's other generating resources and purchasing programs must satisfy, and thus, these criteria alter the optimal capacity expansion path. Tables 26 and 27 summarize the changes in the optimal selection of technology type under the four commitment-level alternatives under the high-flexibility scenario. Table 26 summarizes variations across commitment-level alternatives in terms of capacity additions, while Table 27 shows the percent change in the mix of additions.

Table 26 shows that, in the near-term (before 1993) under the No Action Alternative, most of the capacity expansion is by simple-cycle gas turbines. Currently, many of the large Western customers have an abundance of base load capacity and little peaking resources (Table 1). Gas turbines are projected to be built to fill this void. In the long term (after 1998), it is projected that a mix of base load coal units and peaking gas turbines units will be constructed. Some combined cycle units will also be built to satisfy intermediate loads. It is projected that the smaller utility systems analyzed in detail will build diesel units fired by natural gas. These systems have system peak demands that grow by only 1 to 3 MW per year.

Under Alternative 2, it is projected that in the near term, more combined cycle and gas turbine units will be added than will be added in the No Action Alternative. In the long term, relatively less gas-turbine capacity and more combined cycle capacity will be added. Under Alternatives 4 and 5, most of the additional capacity needed to compensate for reductions in Western LTF purchases will come from technologies that will help meet peak demands.

As shown in Table 27, the highest percent of the total capacity expansion under all alternatives is for simple-cycle gas turbines. This percentage is significantly higher under Alternatives 4 and 5. As shown in Table 25, these two alternatives are characterized by relatively low LTF capacity allocations, with high load factors and very high minimum schedule requirements. Therefore, these alternatives have relatively lower amounts of discretionary energy (Table 9) to use to meet peak demands. A marked increase in the selection of combined cycle technology is observed under Alternative 2 as the technology comprises 14% of the total capacity expansion. This total is nearly three times higher than that for the other alternatives. Coal technology accounts for 45-58% of the total capacity additions, with the No Action Alternative and Alternative 2 tending to have relatively higher percentages of coal technologies.

9.1.3 Effects on the Selection of Unit Size

Although there is a close affinity between type and size of technology options, changes in selecting the size of units within a technology class are largely governed by the magnitude of changes in annual loads. The effects of the alternatives on the selection of the size of units are presented in Table 28. Within the diesel category, the large units are selected under Alternative 4 relative to the no-action alternative. Under all alternatives, the 80-MW class of gas turbines was the main selection; however, a relatively large number of small gas turbines were also selected under Alternatives 4 and 5. As with coal, selecting the

TABLE 26 Selection of Technology Type for the 12 Large Western Customers

	Cumulative Capacity Additions (MW)			
Time Period/ Technology Type	No Action	Alternative 2	Alternative 5	Alternative 4
1993-1998				
Diesel	2.2	0.0	0.0	22.0
Gas turbine	505.2	512.9	896.9	1,075.8
Combined cycle	0.0	199.7	13.7	13.7
Pulverized coal	170.0	210.0	180.0	210.0
Coal IGCC	0.0	0.0	0.0	0.0
Total	677.4	922.6	1,090.6	1,321.5
Increase from No Action (%)	0.0	36.2	61.0	95.1
1993-2007				
Diesel	5.1	0.0	0.0	25.2
Gas turbine	1,019.4	984.4	1,788.3	1,812.5
Combined cycle	27.4	240.3	41.1	54.3
Pulverized coal	690.0	730.0	710.0	740.0
Coal IGCC	800.0	800.0	800.0	800.0
Total	2,541.9	2,754.7	3,339.4	3,432.0
Increase from No Action (%)	0.0	8.4	31.4	35.0

TABLE 27 Cumulative Capacity Expansion Mix by Technology Type (1993-2007)

Technology Type	No Action (%)	Alternative 2 (%)	Alternative 5 (%)	Alternative 4 (%)
Diesel	0.2	0.0	0.0	0.7
Gas turbine	40.1	35.7	53.5	52.8
Combined cycle	1.1	8.7	1.2	1.6
Pulverized coal	27.1	26.5	21.3	21.6
Coal IGCC	31.5	29.1	24.0	23.3

TABLE 28 Effects of Commitment-Level Alternatives on Selecting the Size of Units for the 12 Large Western Customers

Unit Type and Size (MW)	Total Capacity for 1993-1998 (MW)[a]				Total Capacity for 1993-2007 (MW)[a]			
	No Action	Alt. 2	Alt. 5	Alt. 4	No Action	Alt. 2	Alt. 5	Alt. 4
Diesel								
2.4	2.2	0.0	0.0	0.0	2.2	0.0	0.0	0.0
3.2	0.0	0.0	0.0	0.0	2.9	0.0	0.0	2.9
12	0.0	0.0	0.0	22.0	0.0	0.0	0.0	22.0
Subtotal	2.2	0.0	0.0	22.0	5.1	0.0	0.0	24.9
Average	2.2	0.0	0.0	22.0	2.6	0.0	0.0	8.3
Gas turbine								
8.8	0.0	7.7	23.1	7.7	7.3	7.7	38.5	23.1
20	0.0	0.0	0.0	16.7	17.3	16.7	67.4	67.4
31	0.0	0.0	51.8	51.8	26.8	0.0	51.4	51.8
40	0.0	0.0	33.4	0.0	106.0	106.0	209.0	175.0
80	505.0	505.2	788.6	100.0	862.0	854.0	1,422.0	1,495.0
Subtotal	505.0	512.9	896.9	1,076.0	1,019.0	984.0	1,788.0	1,812.0
Average	72.1	64.1	52.8	59.8	56.6	57.9	48.3	51.8
Combined cycle								
15.9	0.0	13.7	13.7	13.7	27.4	54.3	41.1	54.3
200	0.0	186.0	0.0	0.0	0.0	186.0	0.0	0.0
Subtotal	0.0	199.7	14.0	14.0	27.4	240.3	41.1	54.3
Average	0.0	99.9	13.7	13.7	13.7	48.0	13.7	13.6
Pulverized coal								
10	20.0	60.0	30.0	60.0	90.0	130.0	110.0	140.0
150	150.0	150.0	150.0	150.0	300.0	300.0	300.0	300.0
300	0.0	0.0	0.0	0.0	300.0	300.0	300.0	300.0
Subtotal	170.0	210.0	180.0	210.0	690.0	730.0	710.0	740.0
Average[b]	150.0	150.0	150.0	150.0	200.0	200.0	200.0	200.0
Coal IGCC								
400	0.0	0.0	0.0	0.0	800.0	800.0	800.0	800.0
Total	677.0	923.0	1,091.0	1,322.0	2,542.0	2,754.0	3,339.0	3,431.0
Average[b]	93.9	107.8	81.6	66.4	98.1	105.0	75.1	73.4

[a] Capacity amounts are not always a multiple of the unit size because operational characteristics were adjusted to reflect the general location of the new power plant (Section 7.2.2).

[b] Average values do not include the 10-MW unit.

size of unit across the four alternatives did not change, except for the 10-MW class. These 10-MW "units" are not actual units. Instead, these units represent a reduction in capacity sales from an existing unit; that is, as Western's contract levels are reduced, the utility needs this capacity for serving its load and sells less energy to other utility systems. (The utility that purchases this power is outside of the SLCA/IP marketing area.)

9.1.4 Effects of Hydropower Operational Scenarios on the Large Western Customers

Depending on the commitment-level alternative, SLCA/IP hydropower operational scenarios have either minor or no effects on capacity expansion paths of the large customers. In addition to the effects of expansion paths on large customers, Western may also have to purchase capacity as a result of operational restrictions (Section 5.3). Under some conditions, operational scenarios affect capacity expansion paths because of transmission considerations. Table 29 shows that hydropower operational restrictions do not affect the new capacity built by 1998 and 2007 under Alternatives 2 and 4. However, under the No Action Alternative, 146 MW additional capacity is built by 1998 under the medium- and low-flexibility scenarios compared with the high-flexibility scenario. This difference increases to 292 MW by the year 2007.

In contrast with the No Action Alternative, less capacity is needed when operational constraints are more stringent than the high-flexibility scenario under Alternative 5. In 1998, the medium-flexibility scenario has 33 MW less capacity than the No Action Alternative, and the low-flexibility scenario has 73 MW less. By 2007, the medium-flexibility scenario has 252 MW less capacity, and the low-flexibility scenario has 219 MW less.

9.2 CAPACITY EXPANSION RESULTS FOR INVESTOR-OWNED UTILITIES

It was assumed that capacity expansion paths for investor-owned utility systems are independent of the effects of variations in Western LTF allocations and operational scenarios. Therefore, capacity additions were determined solely on the basis of the system's loads and resources. Optimal paths for investor-owned utility systems are needed to estimate the system production costs used by the spot market module that estimates non-firm transactions between investor-owned utility systems and the large Western customers.

The optimal capacity expansion path for the five investor-owned utilities is shown in Table 30. Aggregate capacity additions for all five utilities over the 15-year expansion period is about 7,604 MW. This amount is about three times that of all SLCA large customers combined under the No Action Alternative and twice as large as Alternative 4. The annual average capacity addition for the investor-owned systems is approximately 543 MW.

TABLE 29 Effects of Operational Scenarios on Total Capacity Expansion for the 12 Large Western Customers

Commitment-Level Alternative	Cumulative Capacity Additions (MW) by Time Period and Operational Scenario					
	1993-1998			1993-2007		
	High	Medium	Low	High	Medium	Low
No Action	677.4	823.4	823.4	2,541.9	2,833.9	2,833.9
2	922.6	922.6	922.6	2,754.7	2,754.7	2,754.7
5	1,090.6	1,057.6	1,017.6	3,339.4	3,087.4	3,120.4
4	1,321.5	1,321.5	1,321.5	3,432.0	3,432.0	3,432.0

TABLE 30 Total Capacity Expansions for Investor-Owned Utilities

Year	Annual Capacity Additions (MW)	Cumulative Capacity Additions (MW)
1993	0.0	0.0
1994	373.2	373.2
1995	562.0	935.2
1996	689.4	1,624.6
1997	514.4	2,139.0
1998	506.6	2,645.6
1999	517.7	3,163.3
2000	800.0	3,963.3
2001	300.0	4,263.3
2002	146.8	4,410.1
2003	600.0	5,010.1
2004	1,089.2	6,099.3
2005	645.4	6,744.7
2006	269.8	7,014.5
2007	589.2	7,603.7
Average annual capacity added (MW)	543.1	

As shown in Table 30, capacity additions consist mainly of three technology types: pulverized coal, AFBC coal and gas turbine. In 2007, pulverized coal units constitute about 48% of the total capacity addition, coal AFBC units constitute about 8%, and gas turbines constitute about 44% (Table 31). Because investor-owned utilities are large compared with most Western LTF customers, size selection tends to favor large units. Among the gas-turbine-size classes, the 80- and the 140-MW sizes were selected. The optimal expansion path also included 200- and 300-MW coal-based units.

TABLE 31 Unit Sizes for Investor-Owned Utilities

Unit Type/Size	1993-1998 Total Capacity Additions[a]		1993-2007 Total Capacity Additions[a]	
	MW	%	MW	%
Gas turbine				
80 MW	1,448	54.7	2,739.6	35.8
140 MW	498	18.8	622.0	8.1
Subtotal	1,946	73.5	3,361.6	43.9
Pulverized coal				
200 MW	0	0.0	400	5.2
300 MW	300	11.3	3,300	43.1
Subtotal	300	11.3	3,700	48.3
Coal AFBC				
200 MW	400	15.1	600	7.8
Total	2,646	100.0	7,661.6	100.0

[a] Capacity amounts are not always a multiple of the unit size because operational characteristics were adjusted to reflect the general location of new power plants (Section 7.2.2).

10 MODELING SPOT MARKET ACTIVITIES

In addition to affecting plans to expand capacity, commitment-level alternatives and dam operational scenarios also affect spot market activities. Unlike LTF commitments, spot market transactions between utility systems are short-term non-firm agreements usually made on an hourly basis. Some spot market energy transactions are arranged one or two days in advance and are referred to as "prescheduled" transactions. Other spot market transactions are arranged only a few minutes before the actual transaction. For some systems, spot market transactions make up a significant portion of the utilities' cash flow and affect the operations of their generating units.

In general, a utility system sells energy when the spot market price is higher than that of the utility system's incremental cost of production. A utility system buys energy on the spot market when the system can purchase energy at less cost than it can produce its own energy, and transmission capabilities are sufficient between the systems to make the energy transaction. However, at times, a utility system may elect to sell spot market energy at a loss because of operational constraints. For example, a utility may sell energy at a loss to keep a unit's generation above the design's minimum operation level. Line losses for transmitting energy must also be considered.

The seller transmits power to the buyer at a specified delivery point. This transaction can involve using the seller's transmission lines, or the energy can be "wheeled" or transmitted through one or more other utility transmission systems. When two utility systems are interconnected, energy is delivered to the buyer without using a third party's transmission lines (i.e., wheeling). However, if transmission lines between the interconnected buyer and seller are fully loaded, energy can be routed through a third party's transmission system. Typical wheeling charges range from 2 to 4 mill/kWh. When two utility systems are not interconnected, a third utility system that can transmit energy between these two systems can purchase power from one system and sell it to another system at a profit. This arrangement is called a "sales-for-resale" transaction.

10.1 ESTIMATING SPOT MARKET ACTIVITIES

Spot market activities depend on the commitment-level alternative and dam operational scenario because these factors influence the capabilities and the spatial distribution of generating resources. First, capacity expansion paths for Western's customers depend on the capacity and energy offered under a commitment-level alternative. The capacity expansion path prescribes the type and amount of capacity that a utility builds to serve its load and to apply to spot market sales. Second, the amount of firm SLCA/IP energy received by customers affects hourly marginal production costs and excess capacity levels. When a customer receives less firm energy, it tends to lower the resources that the utility system has available for spot market sales; that is, more resources are used to satisfy the utility's own loads. Third, hydropower operational restrictions, together with aggregate SLCA/IP hourly firm demands, affect Western's purchases and non-firm sales (Section 6.3).

For example, if Western must operate all of its hydropower plants at a constant water release rate, and its firm load varies significantly over time (e.g., the high-capacity, high-energy marketing alternative), then usually Western's loads and hydropower plant generation will not be equal. This scenario forces Western to either spill water or sell excess energy when loads are less than the generation level produced by a constant hydropower flow. On the other hand, Western has to purchase power (i.e., on the spot market or through a firm contract) when loads are greater than the hydropower plant generation.

The effects of commitment-level alternatives on spot market activities among the 17 utility systems under investigation were estimated by the Spot Market Network (SMN) module. This module is an LP formulation that minimizes net costs at the utility system level. Costs are minimized by determining non-firm energy contracts between utility systems that will minimize collective production costs for serving all loads. Energy transactions between systems benefit both the buyer and the seller of energy.

The SMN estimates spot market activities on an hourly basis. Each hour simulated represents a different module run and is independent of all other hours simulated. For this analysis, the SMN was run for all hours in a week, and weekly runs were performed for each month of the year. Therefore, spot market activities for 17 utility systems were estimated for 2,016 h/yr (i.e., 24 h/day for 7 day/week for 12 month/yr). Monthly results were estimated by applying scaling factors to aggregated weekly results. For example, spot market transactions for January 1993 were estimated by running SMN for a one-week period in the middle of the month (Table 22). Hourly SMN results such as spot market prices, purchases, sales, generation costs, and profit margins are then aggregated and multiplied by approximately 4.4286 (i.e., 31/7 — 31 days in January versus 7 days in the week run) to obtain estimates for the entire month.

Spot market network runs were performed for 1993, 1998, and 2008 under dry, normal, and wet hydropower conditions. The year 1993 is the first year of the study period, and 2008 is near the end of Western's LTF contracts. The year 1998 was also run because CRSS projects this year will have on average the highest hydropower conditions. Estimates for all other years were performed by interpolation. Although interpolations lead to some errors, these errors are usually rather small. To estimate the potential for interpolation errors, total annual generation costs under the No Action Alternative (i.e., fuel costs, variable O&M costs, and unserved energy costs) from ICARUS simulations were aggregated for large Western customers and for investor-owned utility systems. Costs were then estimated for the years between 1993, 1998, and 2008 via linear interpolation. Interpolated results were compared with actual values calculated by ICARUS. The results showed that interpolated values for the large Western customers averaged about 0.3% higher than the actual value computed by ICARUS. The average error for aggregate investor-owned systems was somewhat higher (i.e., 3.0%). When all systems were aggregated, the error was about 1%, ranging from -1.0 to 2.8% in any one year.

The SMN module was run for 36 different situations, that is, all possible combinations of the four commitment-level alternatives, three operational scenarios, and three hydropower conditions. For each of the situations, spot market activities for the 17 utility systems were estimated for 6,048 different hours (i.e., 2,016 h/yr for 3 years). Ideally, SMN could be run every hour of the year and for all years. However, the time required to make this number of runs would have been prohibitive and would probably not change the overall conclusions of the analysis.

10.2 SPOT MARKET NETWORK LINK AND NODE REPRESENTATION

The SMN estimates spot market activities by using a network of nodes and links. Nodes represent generating resources, load centers, and distribution transshipment points. Generating resources or supply nodes are comprised of piecewise linear marginal cost curves, and load centers are represented by electricity consumption or energy "sinks." Nodes are connected via links that represent transmission limitations, ownership, and losses.

10.2.1 Spot Market Network Supply Nodes Representation

In the SMN, supply nodes represent electric generating resources. For this analysis, the SMN was configured with 17 supply nodes — one per utility system. Each supply node contains a piecewise linear marginal cost curve. The curve represents the additional cost of increasing production by an additional unit (e.g., kW) of output. It also represents systemwide minimum and maximum generation capabilities. The limits (i.e., starting and ending points) and the shape of this curve depend on the unit-level characteristics of generators on-line in a utility system. Important unit characteristics include maximum operating capacity, forced outage rates, variable O&M costs, fuel costs, and heat rate curves. Units that are on-line at a specific time are obtained from results produced by the capacity expansion module and include existing, announced, and new units. Units scheduled for maintenance during a specific week are not represented in the curve.

To account for the effects of forced outages, the ICARUS module is run in the hourly mode for 26 different load levels. Production values simulated range from the system's minimum production level to its maximum on-line capacity. Production cost estimates are then used to construct the maximum cost curve. A least-squares curve fitting algorithm reduces the number of points in this 26-point curve and ensures that the curve is convex upward. For this analysis, each production cost curve is represented by five points. Slopes between the selected points represent short-run marginal costs.

Because PACE schedules unit maintenance biweekly, short-run marginal costs were generated for 26 periods per year for each of the 17 utility systems. Curves were generated for 1993, 1998, and 2010. Because commitment-level alternatives affect capacity expansion paths and unit maintenance schedules, a different set of short-run marginal cost curves was constructed for each alternative.

10.2.2 Spot Market Network Demand Nodes Representation

In the SMN, demand nodes represent energy sinks or areas of energy consumption. For this analysis, the SMN was configured with 19 utility-level demand nodes. Seventeen nodes represent energy demands for the 17 large utility systems in this investigation and the two remaining nodes represent net energy transfers to northern and southern California. Typically, energy transfers to California were obtained from EIA's electric trade database and from discussions with utility system dispatchers.

Hourly demands used by the SMN are consistent with loads used to construct load duration curves input into the ICARUS (i.e., dispatch) module. Where available, demands are adjusted to account for firm contracts. Sales contracts increase loads, while purchases decrease loads. Load adjustments take into account transmission losses, where applicable. For example, the demand for a utility system that sells power may be increased by 100 MW, while the demand for the utility system that receives the energy is reduced by only 93 MW. As described in detail in Section 7.2.5, the impact of these transactions on the transmission system is also taken into account. The SMN also accounts for contract contingencies by adjusting loads only when the seller has the ability to supply the buyer with energy. That is, because of forced outages, the seller may have reduced generating capabilities, thereby lowering or halting the sale of firm power.

Hourly demands for the large Western customers are reduced by the load reduction algorithm. The level of demand reduction in each hour depends on the commitment-level alternative and STF sales. Important commitment-level alternative parameters input into the load reduction algorithm include SLCA firm capacity and energy levels and minimum schedule requirements. The STF SLCA/IP energy sales are approximated by the method described in Section 6.2 and depends on the commitment-level alternative, operational restrictions, and hydropower condition.

Because the SMN simulates spot market activities only for one week per month, the load reduction algorithm is also run on a weekly basis for each of the large Western customers. This algorithm estimates hourly Western firm demands (Section 8.3.1.3). When the algorithm is run for less than a month, the total demand that is reduced during the simulation period is proportionally lowered. For example, if the peak reduction algorithm is run for one week in January, only 22.6% (i.e., 7/31) of the monthly energy purchase is used to reduce energy demands during the week. However, maximum and minimum demand reduction constraints are not altered.

10.2.3 Transshipment Nodes

A transshipment node is analogous to a substation without generation capabilities. The total energy flow entering a transshipment node must equal the total energy flow exiting the node. The purpose of this node is to route electricity from one or more node input links to one or more output links. For example, energy flows from one input link can branch onto several output links that have smaller carrying capacities. Conversely, several small transmission links can feed into one large output link.

10.2.4 SLCA Node and Interaction with the Hydro LP Module

Because Western's generating resources are limited by the amount of water stored in reservoirs and because of the complex set of operational restrictions analyzed in the power marketing EIS, it would be inaccurate to represent Western as a set of supply-and-demand nodes. Rather, the Hydro LP module estimates hourly hydropower plant operations and Western's purchases and non-firm sales (Section 6.3.1.2). To measure the effect of Western's purchases and sales (as determined by the Hydro LP) on other utility systems, a third node is incorporated into the SMN. In this node, hourly purchases by Western are represented as an energy sink, while non-firm sales are represented as energy supplied to the grid.

For the Hydro LP module to make "correct decisions" on hourly transactions, it must have estimates of hourly prices from the SMN. This need creates a "chicken-and-egg" problem: the SMN requires information about Western's purchase and sales activities that are estimated by the Hydro LP module; the Hydro LP module requires price data generated by the SMN. Ideally, the two modules should be combined so that the two problems can be solved simultaneously. However, the LP problem would be extremely large and exceed the limits of LP software packages currently available at ANL. Computer run times would also be significantly increased. Therefore, the SMN was run to provide the Hydro LP module with initial estimates of hourly prices.

In the initial SMN run, all purchase and sales transactions made by Western were set to zero. The Hydro LP module was then run with preliminary prices from the SMN to obtain estimates of spot market transactions. The SMN was run again with Western's hourly transactions. Western's activities in the spot market do not significantly affect prices because these activities are small compared with the combined resources of the 17 large utility systems. Therefore, it was not necessary to rerun the Hydro LP module a second time to obtain a revised estimate of Western's purchases and sales.

10.2.5 Transmission Representation

Transmission lines in the SMN are represented as links that connect two nodes. A single node can also be connected with two or more links representing multiple pathways to that node. In general, ANL used TOTs (i.e., groups of power lines serving the same area) when constructing the network. TOTs are also used by the various dispatchers in the western United States in their daily operations. However, in some cases, individual lines were also represented in the SMN. In general, lines 115 kV and above are incorporated into the SMN. Lines less than 115 kV were assumed to be part of the distribution system.

Transmission line capacity is specified in SMN as a maximum net hourly energy transaction in terms of megawatt-hours per hour. The module only limits net energy transfers; that is, an energy transaction scheduled in one direction over a line can exceed the line capacity if at the same time an energy transaction is scheduled in the opposite direction (i.e., back scheduling) that will lower the net energy transaction over the line below its capacity.

Data on transmission capabilities between utility systems were obtained via NERC transmission maps (see *Coordinated Bulk Power Supply Program 1990-2000* — WSCC [1991a]) and numerous discussions with several utility companies. Western area offices were also contacted for information regarding control area boundaries and tie lines between adjacent control areas. In many cases, information was provided by a primary utility system. This network information was then further discussed with neighboring utilities to determine completeness and accuracy. In general, transmission capabilities are expressed in terms of additional transactions that could occur, taking into consideration inadvertent power flows and other transmission considerations.

Transmission losses are represented in SMN by applying a loss factor to net energy transaction over each of the links. That is, the demand node receives only a fraction (i.e., approximately 92-96%) of the energy produced at a generating node. Values for demand input into utility demand nodes include system losses. Therefore, losses for a utility serving its own demand were set to zero (i.e., a 1.0 loss factor). For this analysis, transactions between utility systems in the same load control area were also assumed to be zero. However, transmission losses for energy transactions between utility systems located in different load control areas were generally set to about 6%.

The SMN also recognizes line rights and wheeling charges incurred when one utility system uses another system's transmission lines. Wheeling charges in SMN vary between 2 and 4 mill/kWh depending on utility line rights. An individual transmission line that has several utility systems with line rights was represented in SMN as several links. The sum of these links equals the total capacity of the transmission line. Capacities of each individual link in SMN are based on the portion of the line that a utility system has rights to use. If a utility system wants to transmit more energy over a line than it has rights to use, energy can be wheeled over another system link. However, wheeling charges will be incurred.

Link capacities were adjusted for transmission line usage that is reserved for serving LTF contractual commitments. For example, line usage for serving Western's demand was subtracted from total link capacities in order to represent decreased line availability for spot market activities. As described previously, values at demand nodes are adjusted for firm contracts. Line adjustments were made on the basis of time of day (on-peak, off-peak and shoulder hours), day of the week (week day or weekend), season (winter and summer) and year.

In addition to the features of the Western node, the price of energy that exits the node through output links is increased by 3 mill/kWh. This price increase represents a sales-for-resale transaction margin that Western must earn before a transaction is made. The 3 mill/kWh value is based on information found in monthly operating guidelines used by dispatchers at the Montrose office. The Western node also has a limit on the amount of energy in one hour that can be transmitted from one set of links to a second set of links. That is, the aggregate amount of energy that flows from utility systems east of Western to utility systems west and southwest of Western cannot exceed 380 MWh/h. This constraint in SMN represents the transmission limits on the Glen Canyon-Kayenta-Shiprock line.

10.3 SIMPLE HYPOTHETICAL NETWORK

In a simple hypothetical network consisting of two utility systems (i.e., utilities A and B) with infinite transmission capabilities and zero line losses, spot market transactions are made in SMN such that marginal production costs for both utilities are approximately equal. When spot market transactions do not occur, utility system A must generate all of the energy to satisfy utility A's load, and utility B must generate all of the energy to serve utility B's load. However, both systems may benefit from an energy transaction if the marginal production cost (i.e., the cost to produce one more kilowatt-hour of electricity over a specific production level) for utility A is lower than utility B's marginal production cost. That is, total costs for serving the collective demand for both systems would be reduced if utility A sells power to utility B. The amount of power that utility A sells to utility B depends on the marginal production cost curves of both systems. In general, the more power that utility A sells to utility B, the higher the marginal cost of production for utility A. For example, utility A can produce an additional 100 MW above its own load by generating more power at one of its inexpensive coal power plants. However, utility A may have to fire up a gas turbine to sell 110 MW of power. On the other hand, the marginal production cost for utility B tends to decrease as it purchases more energy. Utility B will decrease production at its most expensive units (i.e., gas turbines) first, while keeping lower cost units on-line. In this example, costs for serving the collective loads of both systems are minimized when marginal production costs are equal. Sales by utility A greater than this equilibrium level would lead to higher overall costs because utility B can produce less expensive energy. Conversely, a lower sales level by utility A would also lead to a higher overall cost because utility A can produce the power less expensively than utility B.

10.4 SPOT MARKET NETWORK FORMULATION FOR THE POWER MARKETING EIS

The network that adequately reflects spot market activities between the 17 utility systems and Western under investigation is more complex than the simple two-system network discussed in Section 10.3. Several factors in addition to production costs must be taken into consideration:

- Physical limits on transmission lines,
- Line-specific loss factors,
- Multiple transmission routes between utility systems,
- Line rights and wheeling charges for the line usage,

- Generating resources and transmission line usage earmarked for LTF power commitment,
- Sales-for-resale transactions,
- Minimum "profit" margins,
- Unit and line outages, and
- Minimum system generation levels.

With the exception of line outages, the SMN considers each of these factors.

Figure 29 shows a simplified version of the network used for this analysis. Rectangles represent load control areas, and ovals represent utility systems. Although there are exceptions, utility systems within a load control area are assumed to have unlimited transfer capability when direct interconnections are identified. Additional details are included in SMN to capture specific network interactions, but those are not reflected in Figure 29 in order to preserve the confidentiality of utility-specific data provided to ANL.

The objective of the SMN model is to minimize the cost of satisfying loads. As shown in the objective function below, costs include electricity production costs, wheeling costs, and transaction costs (or minimum profit margin):

$$\text{minimize } \Sigma_u \Sigma_s \Sigma_k \, C_k XA_{ksu} + \Sigma_i \Sigma_j \, t_{ij} \, XW_{ij} + \Sigma_u \Sigma_i \, m_{ui} X_{ui} \,, \tag{10.1}$$

where

C_k = production cost for supply curve segment k (mill/kWh);

k = supply cost curve segment, k = A, B, C, ...;

u = utility code name for u = A, B, C, ...;

m_{ui} = transaction cost on link u, i (mill/kWh), for u = A, B, C, ... and i = 1, I;

s = supply node for s = S_1, S_I;

t_{ij} = wheeling cost on link i, j (mill/kWh), for i = 1, I, and j = 1, J;

XA_{ksu} = generation for cost curve segment k (MWh) that falls between V_{k-1} and V_k, for supply node s = S_1, S_I;

V_k = generation at break point of supply segment k (MWh), for k = A, B, C, ...;

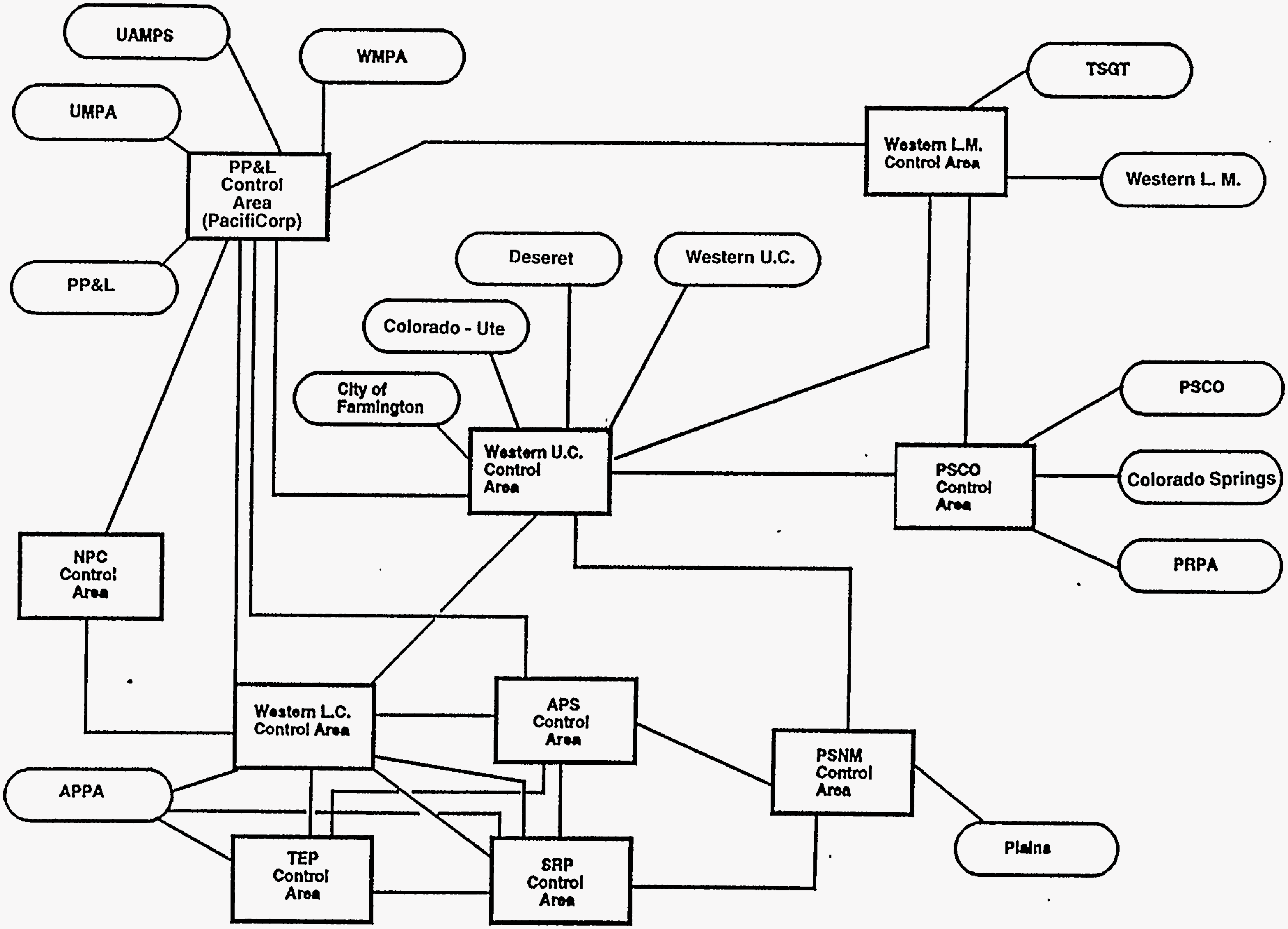

FIGURE 29 Simplified Depiction of the Spot Market Network

X_{ui} = power flow on link u, i (MWh), for u = A, B, C, ... and i = 1, I; and

XW_{ij} = power flow on wheeling link i, j (MWh), for i = 1, I, and j = 1, J.

The objective function is subject to several classes of constraints. One class is a limit on electricity generation at each supply node. Electric generation XA is divided into k supply segments — the sum of which equals the maximum generation level. Each generation segment has a corresponding cost C_k that represents the short-run marginal cost curve. This curve starts at min_{su}, which represents a utility system's minimum output level in any one given hour:

$$\Sigma_k XA_{ksu} - X_{su} = min_{su} \text{ for all s and u} \tag{10.2}$$

and

$$XA_{ksu} \leq V_k - V_{k-1} \text{ for all k and s,} \tag{10.3}$$

where

min_{su} = minimum power flow from supply node s to a utility node u (MWh), for s = S_1, S_I and u = A, B, C, ...; and

X_{su} = power flow from supply node s to the utility node u (MWh), for s = S_1, S_I, and u = A, B, C, ...

Electricity generation can serve a utility system's own load, or it can be sold to the grid. If two utility systems are directly connected, wheeling charges are set to zero:

$$X_{ui} - \Sigma_j (1 + l_{ij}) X_{ij} = 0 \text{ for all u, i,} \tag{10.4}$$

where

l_{ij} = line loss factor on link i, j (fraction), for i = 1, I, and j = 1, J; and

X_{ij} = power flow on link i, j (MWh), for i = 1, I and j = 1, J.

Another set of constraints is a node balance constraint. For energy source node type, the node represents a demand center, and the net flow at node d_i is negative. For the power marketing EIS, demands were adjusted for LTF purchases and sales. Sales were added to a utility system's demand, and purchases were subtracted. Energy flows on some links i, j also resulted in losses (i.e., transmission line losses):

$$X_{ui} + X_{ul} - X_{su} = 0 \text{ for all u, i, and l;} \tag{10.5}$$

$$-X_{ul} - X_{il} = -d_i \text{ for all u, i, and l;} \tag{10.6}$$

and

$$X_{il} - \Sigma_j X_{ji} + \Sigma_j (1 + l_{ij}) XW_{ij} - \Sigma_j XW_{ji} = 0 \text{ for all i, and l;} \tag{10.7}$$

where

X_{ul} = power flow from a utility u to the demand load center l for u = A, B, C, ... and $l = l_1, l_I$;

X_{il} = power flow from the grid node i to the demand load center l for i = 1, I and $l = l_1, l_I$; and

d_i = electricity demand for an hour (MWh), for i = 1, I.

For the nonenergy source node type, node i is a transshipment node. The total energy flow entering node i must equal the total energy flow exiting node i. One or more links enter a transshipment node, and one or more exit it. The net flow at node d_i is zero. Energy flows on some links i, j also result in losses (i.e., transmission line losses):

$$\Sigma_j (1 + l_{ij}) X_{ij} - \Sigma_j X_{ji} + \Sigma_j (1 + l_{ij}) XW_{ji} - \Sigma_j XW_{ji} = 0 \text{ for all i.} \tag{10.8}$$

For a surplus/deficit node, the node d_i can represent either the surplus or deficit demand center. This node does not supply energy. If the net flow from node d_i is negative, it represents an energy sink (or deficit). If the net flow from node d_i is positive, it represents an energy surplus. Energy flows on some links i, j also result in losses (i.e., transmission line losses):

$$\Sigma_j (1 + l_{ij}) X_{ij} - \Sigma_j X_{ji} + \Sigma_j (1 + l_{ij}) XW_{ji} - \Sigma_j XW_{ji} \tag{10.9}$$

$$= (+/-)\, d_i \text{ for all i and l.}$$

Electricity flows on a transmission line are represented by flows on each link i, j that can have up to four components per utility that has line rights (two normal links with one in each direction and two wheeling links with one in each direction). The net flow on the line is constrained by a power flow limit, as shown in the following equations:

$$XW_{ij} - XW_{ji} + X_{ij} - X_{ji} \leq b_{ij} \text{ for all i, j,} \tag{10.10}$$

and

$$-XW_{ij} + XW_{ji} - X_{ij} + X_{ji} \leq b_{ij} \text{ for all i, j,} \tag{10.11}$$

where b_{ij} is the power flow limit on link i, j, (MWh), for i = 1, I, and j = 1, J.

Electricity in an amount up to the amount that can be transported by the utility's internal transmission system can be taken from the grid.

10.5 NET SPOT MARKET TRANSACTIONS

Table 32 shows projected net spot market transactions for large Western customers as a function of commitment-level alternative, hydropower condition, operational flexibility, and projection year. In general, net spot market sales increase between 1993 and 1998. During this time, excess base load generating capacity is expected to decline because of moderate load growth with minimal capacity expansion. While SLCA customers are still projected to have some excess in 1998, other systems are expected to have much smaller or no base load surpluses. These systems will find it attractive to increase spot market transactions with SLCA customers to minimize the use of more expensive generating units. As shown in Figure 19, a testimony to higher demand for spot market energy is the projected price increase over time. However, between 1998 and 2007, net spot market transactions for Western customer utility systems begin to decrease. Internal load growth for the large Western customers during this period decreases the excess capacity for these utility systems. Investor-owned utility systems are also projected to build base load coal-fired capacity (Table 32 is only for all SLCA LTF customers). Although some of the Western customers are net purchasers of power, most customers are net sellers of energy. Some of the customer's sales are also to Western, which, in turn, resells it to customers as LTF energy.

Another trend that is evident in Table 32 is that the more firm energy (long term plus short term) that customers receive, the greater the net spot market sales. For example, net spot market sales tend to be the highest under the No Action Alternative and the lowest under Alternative 4. Because significant amounts of the SLCA energy is sold on the STF market under Alternative 2 (Table 17), net spot market sales under this alternative are the highest under wet conditions and lowest under dry conditions. However, under commitment-level Alternatives 4 and 5, net sales are lower as hydropower conditions improve. Under Alternative 4, STF sales are limited by LTF capacity sales (i.e., limited by a 100% sales load factor) and are zero under Alternative 5. Therefore, most of the excess SLCA energy is sold on the spot market, thereby reducing the demand for spot market energy

TABLE 32 Net Spot Market Sales for the 12 Large Western Customers as a Function of Commitment-Level Alternative, Operational Scenario, and Hydropower Condition

Commitment-Level Alternative/ Hydropower Condition	Weighted Average Net Spot Market Sales and Purchases by Hydropower Operational Scenario (GWh/yr)								
	High Flexibility			Medium Flexibility			Low Flexibility		
	1993	1998	2007	1993	1998	2007	1993	1998	2007
No Action									
Dry	3,516	5,581	4,953	3,463	5,557	4,747	3,569	5,609	4,723
Normal	3,152	5,126	4,442	3,130	5,101	4,130	3,272	5,030	4,094
Wet	3,064	5,705	4,468	3,119	5,764	4,888	3,222	5,757	4,796
Weighted average	3,329	5,423	4,624	3,313	5,391	4,553	3,388	5,431	4,531
Alternative 2									
Dry	2,006	3,962	3,162	2,021	3,987	3,005	1,995	3,945	2,960
Normal	2,154	4,263	3,292	2,165	4,230	3,500	2,161	4,228	3,291
Wet	2,954	5,614	4,209	2,684	5,646	4,616	2,711	5,668	4,444
Weighted average	2,154	4,349	3,429	2,176	4,355	3,363	2,202	4,336	3,303
Alternative 4									
Dry	2,086	3,575	3,564	2,159	3,611	3,470	2,121	3,570	3,378
Normal	2,977	3,598	3,509	2,030	3,533	3,303	2,124	3,527	3,350
Wet	1,521	1,991	2,280	1,656	1,972	1,889	1,704	1,966	2,074
Weighted average	1,955	3,364	3,273	2,034	3,339	3,234	2,065	3,294	3,150
Alternative 5									
Dry	3,155	5,343	5,435	3,172	5,434	5,261	3,306	5,448	5,141
Wet	2,798	4,888	4,890	2,877	4,982	4,405	3,006	4,915	4,513
Normal	2,252	3,193	3,394	3,242	3,256	2,978	2,378	3,239	3,155
Weighted average	2,890	4,831	4,776	2,945	4,901	4,716	3,018	4,890	4,606

from the large customer utility systems. Note also that operational scenarios have relatively minor effects on net purchases because, for a given commitment-level alternative, customers receive almost identical amounts of Western energy under identical terms regardless of Western's SLCA/IP resources.

10.6 SPOT MARKET PRICES

Spot market prices are projected to vary by time of day, season, projection year, and geographic location. For example, in the northeastern SLCA marketing region, spot market prices tend to be lower (2 to 5 mills, depending on the situation) than prices in the southwestern marketing area. These price differences are mainly the result of variations in production costs for various generating stations and transmission considerations such as limitations, losses and costs. Spot market prices during the spring and fall tend to be low, and prices are high during the summer. However, the SMN does indicate that some periods during the off-peak months have high prices. Higher prices occur when large inexpensive base load units are taken off-line for scheduled maintenance. In 1993, off-peak prices in the northeast are on the order of 14.5 to 16.1 mill/kWh, and on-peak prices reach 32.1 mill/kWh during the summer. In the southeast, off-peak prices are about 17 to 18 mill/kWh and increase to 38 mill/kWh or more during on-peak periods. The SMN shows that Western often takes advantage of these regional price differentials and its extensive transmission network by buying relatively inexpensive power in the northeast and selling it to more expensive markets in the southwest.

11 CAPITAL AND VARIABLE COSTS

As discussed in previous sections, commitment-level alternatives affect capacity expansion plans of Western's customers and the manner in which customer supply-side resources are dispatched. Restricting hydropower plant operations alters the way in which SLCA/IP hydropower plants are operated. Both commitment-level alternatives and hydropower plant operations affect the amount of energy that Western LTF customers sell to other utility systems and Western's purchases of energy and non-firm energy sales. This section discusses the cost of altering SLCA commitment levels and restricting SLCA/IP hydropower plant operational flexibility. Costs are provided separately for large Western customers, investor-owned utility systems, and for Western's SLCA office. Utility financial analysts analyzed the impacts on small SLCA customers (Bodmer et al. 1995).

11.1 WESTERN LONG-TERM FIRM CUSTOMERS

When a customer has a reduction in Western LTF capacity, the capacity lost must eventually be replaced to meet load. This usually means constructing additional capacity, purchasing replacement capacity from another utility system, or implementing more aggressive DSM programs. As discussed in Section 9, it is projected that additional units above the No Action Alternative will be constructed by Western customers to replace reductions in LTF capacity and energy allocations. These reductions are not expected to affect DSM programs (Cavallo et al. 1995). Both capacity expansion paths and reductions in Western LTF energy will also affect the dispatch of customer unit generators and regional spot market activities.

It should be noted that capital investments and O&M costs do not include expenditures that may be required for additional transmission lines or upgrades. These costs are highly dependant on the exact location of newly constructed generating units. Some of these units may be located at existing power plants, whereas others may be built on a new power plant site. Siting of new generating units is a very involved process and must be performed on a case-by-case basis. If transmission expenditures were included, total costs may be higher than those reported in this document. Commitment-level alternatives with relatively low LTF capacity allocations (e.g., Alternative 4) may have larger cost additions than those of commitment-level alternatives with high LTF capacity allocations.

11.1.1 Capital Costs

Capital investments for the construction of new electric generating units were determined for each commitment-level alternative and hydropower operational scenario. Table 33 shows investment streams as a function of time and commitment-level alternative for the high-flexibility scenario. Although it may take several years to construct a new unit, all construction costs presented in the table are reported in the year in which the new unit

TABLE 33 Comparison of Capital Investment Streams by Commitment-Level Alternative for the 12 Large Western Customers for the High-Flexibility Scenario[a]

Year	No Action Alternative Annual Invest. ($\$10^6$)	No Action Alternative Cumulative Investments ($\$10^6$)	Alternative 2 Annual Invest. ($\$10^6$)	Alternative 2 Cumulative Investments ($\$10^6$)	Alternative 5 Annual Invest. ($\$10^6$)	Alternative 5 Cumulative Investments ($\$10^6$)	Alternative 4 Annual Invest. ($\$10^6$)	Alternative 4 Cumulative Investments ($\$10^6$)
1993	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1994	74.60	74.60	193.39	193.39	282.55	282.55	331.47	331.47
1995	42.58	117.19	37.20	230.59	56.85	339.40	90.22	421.69
1996	74.40	191.59	179.00	409.58	361.76	701.17	362.47	784.16
1997	362.47	554.06	325.27	734.86	92.42	793.58	87.41	871.57
1998	0.00	554.06	16.98	751.83	0.00	793.58	22.48	894.05
1999	486.54	1,040.60	486.54	1,238.38	516.24	1,309.82	486.54	1,380.59
2000	0.00	1,040.60	0.00	1,238.38	0.00	1,309.82	7.23	1,387.82
2001	96.26	1,136.86	72.07	1,310.44	135.10	1,444.92	101.15	1,488.97
2002	574.09	1,710.95	574.09	1,884.53	572.45	2,017.37	535.25	2,024.22
2003	37.21	1,748.16	37.21	1,921.74	47.90	2,065.27	72.09	2,096.31
2004	6.09	1,754.25	0.00	1,921.74	375.62	2,440.89	392.60	2,488.90
2005	325.27	2,079.52	882.38	2,804.12	7.23	2,448.12	16.92	2,505.83
2006	629.34	2,708.86	16.92	2,821.05	616.19	3,064.31	616.19	3,122.02
2007	20.21	2,729.07	76.66	2,897.70	89.68	3,153.98	83.37	3,205.39

	No Action Alternative	Alternative 2	Alternative 5	Alternative 4
Summary				
Annual average invest.	181.99	193.23	210.25	213.67
NPV with salvage	559.87	677.84	750.21	787.46
NPV without salvage	1,821.88	1,997.23	2,179.97	2,233.92
Average costs ($/kW)				
Total investment	1,073.60	1,051.87	944.50	934.01
NPV with salvage	220.31	246.11	224.70	229.41
NPV without salvage	716.70	725.05	652.79	650.86
Fixed annual payment ($/kW)				
Total investment	65.62	64.44	57.70	57.06
NPV with salvage	20.66	23.12	21.20	21.52
NPV without salvage	67.23	68.19	61.45	61.23
Cost above No Action ($\$10^6$)				
Total investment	0.00	168.60	424.88	476.37
NPV with salvage	0.00	117.97	190.33	227.59
NPV without salvage	0.00	175.35	358.08	412.04

[a] All costs are in constant 1994 dollars.

is projected to come on-line. Costs have been adjusted to reflect investment profiles over the construction period, interest rates, and allowance for funds during construction. In general, capital expenditures for new construction under Alternatives 2, 4, and 5 tend to be higher and occur sooner than those for the No Action Alternative. Patterns in investments do not usually follow the total megawatts of capacity additions because a large disparity in cost exists among different technology expansion options.

Table 33 also compares the various alternatives in terms of total cumulative capital investments, net present values (NPVs) of these investments, and average annual investments. The No Action Alternative is the least expensive among the alternatives with total cumulative investments of approximately $2,729 million over the 15-year contract period. The NPV of investments for this alternative is about $560 million, when a salvage value is subtracted from total costs, and about $1,822 million when the salvage value is not considered. All of the units built under each of the capacity expansion plans will operate for many years after the end of the 15-year contract period (i.e., most units are expected to operate at least 30 years or longer). The value of these resources at the end of the study period (i.e., the year 2007) is taken into account by a salvage value. Alternative 4 has the lowest amount of Western LTF capacity and energy purchases and results in the highest cumulative total capital expenditures over the 15-year contract period, with $3,205 million or about 17% higher than the No Action Alternative. The NPVs with and without salvage value for Alternative 4 are 41% and 23% higher than those for the No Action Alternative, respectively. Total cumulative investments for Alternatives 2 and 5 are also greater than those for the No Action Alternative by about 6 and 16%, respectively. The NPV of investments for these two alternatives with salvage value, on the other hand, is 10 and 20% more than those for the No Action Alternative.

Increases in average annual investments above the No Action Alternative for Alternatives 2, 5, and 4 are $11.2 million, $28.3 million, and $31.7 million, respectively. Capital expenditures and differences between alternatives may be somewhat overstated because under all commitment-level alternatives, economies of scale that would arise from the joint ownership of larger power plants were not considered in this analysis. The isolated system assumption also does not allow for the possibility of new or extended firm capacity purchase agreements between utility systems, which could defer the construction of new units.

An examination of capacity expansion requirements provided in Table 24 and total investment costs in Table 33 shows that in the year 2007 capital investment costs in terms of dollars per kilowatt also vary among commitment-level alternatives. The average capacity investment cost under the No Action Alternative is about $1,074/kW. Costs under Alternative 2 are approximately the same as the No Action Alternative at $1,052/kW, while costs for Alternatives 5 and 4 are $944 and $933/kW, respectively. Assuming average unit lifetimes of 35 years (gas turbines may be somewhat shorter and coal-fired units longer) and a 5% real discount rate, levelized capital investments for the No Action Alternative and Alternatives 2, 5, and 4 are $65.6, $64.4, $57.7, and $57.1/kW-yr, respectively. Average cost differences among alternatives reflect changes in the capacity expansion mix. As shown in Table 27, under Alternatives 5 and 4, more inexpensive gas turbines are built than under the

No Action Alternative and Alternative 2. The size of gas turbines built under Alternatives 5 and 4 also tends to be larger, leading to more economies of scale. Under Alternatives 5 and 4, more capacity is needed, since the large customers have little or no discretionary energy for serving peak loads.

Based on a 5% real discount rate, the NPV of expenditures without considering a salvage value is about $1,821.9 million for the No Action Alternative. Under Alternative 2, the NPV is about $176 million more than the No Action Alternative, and Alternatives 5 and 4 are $359 million and $412 million more expensive. On a dollars-per-kilowatt basis, NPV expenditures for the No Action Alternative and for Alternatives 2, 5, and 4 are $717, $725, $653, and $651/kW, respectively. This cost equates to fixed annual payments over the 15-year contract period of $67.2/kW-yr for the No Action Alternative. Fixed annual payments under Alternative 2 are approximately the same as that of the No Action Alternative at $68.2/kW-yr, while costs for Alternatives 5 and 4 are $61.4 and $61.2/kW, respectively. These fixed payments are approximately equal to the average levelized cost of capital.

When both the time value of money and a salvage value are incorporated into the NPV calculation, expenditures under the No Action Alternative are about $560 million. Cost increases by $169 million, $425 million, and $476 million under Alternatives 2, 5, and 4, respectively. In terms of fixed annual payments, expenditures are $20.7/kW-yr under the No Action Alternative. Fixed annual payments for Alternatives 2, 5, and 4 are $23.1, $21.2, and $21.5 million, respectively.

Differences between scenarios would be greater if the analysis extended beyond the 15-year LTF contract. To project capacity expansion paths during the contract period, PACE capacity expansion runs were made for a 20-year simulation. This 5-year extension alleviates boundary errors (i.e., end effect problems) during the study period. On the basis of a 20-year contract, increases in NPV of expenditures above the No Action Alternative are about 33% higher than when a 15-year contract is used. When including a salvage value, NPVs are about $157 million, $258 million, and $306 million above the No Action Alternative for commitment-level Alternatives 2, 5, and 4, respectively. Costs are higher because more than one large customer is projected to have excess capacity in the year 2007. Therefore, all of the losses in Western LTF capacity are not replaced by building additional capacity.

To estimate the levelized cost of reductions in Western LTF capacity over the 15-year contract, changes in capacity commitments were compared with changes in the NPV of capital investments, including salvage values. Western LTF capacity for the large customers is approximately 582 MW lower under Alternative 5 compared with the No Action Alternative (Table 25). Under Alternative 4, LTF capacity commitments are 647 MW lower. In terms of NPV including the salvage value, capital expenditures for replacing Western LTF capacity are approximately $328/kW under Alternative 5 and $352/kW under Alternative 4. These costs equate to incremental annual fixed payments above the No Action Alternative of $28.7 and $33.1/kW-yr for Alternatives 5 and 4, respectively, and are about 45 to 50% higher than the average fixed annual payment for capacity expansion ($20.64 to $23.1/kW-yr). The increment is higher than the average because when Western LTF capacity is reduced, additional capacity must be built to replace the reduction in LTF capacity and to cover spinning reserves. That is, about 15 to 20% more capacity must be built than the reduction in Western LTF capacity. Reductions in Western LTF capacity also require that capacity expansion begins sooner than under the No Action Alternative. Incremental cost calculations were not performed for Alternative 2 because the low level of LTF energy offered to customers under this alternative results in a devalued LTF capacity; that is, insufficient levels of energy are offered for most customers to adequately use all of the LTF capacity.

Because of a lack of data for Deseret, the level of uncertainty is greater for cost estimates made for this system. Therefore, incremental annual fixed payments above the No Action Alternative were also computed without Deseret. Incremental costs increased by about 13% — to $34.7 and $37.4/kW-yr for Alternatives 5 and 4, respectively.

Although capacity additions are affected primarily by changes in power marketing criteria, at least one utility system is also affected by operational scenario. Table 34 shows NPV expenditures as a function of commitment-level alternative and operational scenario. Changes between commitment-level alternatives tend to be larger than changes between operational scenarios. In general, a customer bases its demands for capacity and energy on Western's firm contracts without regard for SLCA/IP hydropower plant capabilities. Changes in capital expenditures occur because of transmission considerations. Although under Alternative 5, fewer capacity additions are required under the medium-flexibility scenarios than under the other two operational scenarios (Table 29), capital expenditures are higher because units built under the medium-flexibility scenario have higher capital costs on a dollar-per-kilowatt basis.

Capital investments under the high-flexibility scenario for each technology type are summarized in Tables 35 and 36. The total investment costs for pulverized coal and IGCC units do not change across commitment-level alternatives; however, NPVs are slightly higher for pulverized coal units under Alternatives 4 and 5. The reason is that pulverized coal units come on-line sooner under these two scenarios. The capital expenditure for simple-cycle gas turbines is almost twice as high under Alternatives 4 and 5 as compared to the no-action alternative. Because most of the existing capacity for large Western customers is base load coal (Table 1), losses in Western LTF discretionary (i.e., peaking) capacity are replaced with peaking gas units. Alternative 2 shows significantly higher capital expenditures for additional combined cycle capacity. Under this alternative, a utility system has significantly higher discretionary capacity than that under the No Action Alternative (Table 9) but does not have enough Western LTF energy to take full advantage of the capacity. Although peak demands are served through Western LTF energy purchases, intermediate loads are not always served by these purchases. Therefore, additional combined cycle units are constructed to fill this void. Total investment costs for gas turbines are lower under Alternative 2. However, because of the on-line dates of these units, the NPV numbers are higher than those under the No Action Alternative.

TABLE 34 Net Present Value Expenditures for Capacity Expansion by Commitment-Level Alternative and Operational Scenario for the 12 Large Western Customers[a]

	Hydropower Operational Scenario								
	High Flexibility			Medium Flexibility			Low Flexibility		
Commitment-Level Alternative	NPV[b] ($10^6)	Change ($10^6)	Change (%)	NPV[b] ($10^6)	Change ($10^6)	Change (%)	NPV[b] ($10^6)	Change ($10^6)	Change (%)
No Action	559.9	0.0	0.0	607.4	47.5	8.5	607.4	47.5	8.5
2	677.8	118.0	21.1	677.8	118.0	21.1	677.8	118.0	21.1
5	750.2	190.3	34.0	768.7	208.9	37.3	721.9	162.1	29.0
4	787.5	227.6	40.7	787.5	227.6	40.7	790.4	230.5	41.2
	NPV[c] ($10^6)	Change ($10^6)	Change (%)	NPV[c] ($10^6)	Change ($10^6)	Change (%)	NPV[c] ($10^6)	Change ($10^6)	Change (%)
No Action	1,821.9	0.0	0.0	1,929.9	108.0	5.9	2,037.9	216.0	11.9
2	1,997.2	175.3	9.6	1,997.2	175.3	9.6	1,997.2	175.3	9.6
5	2,180.0	358.1	19.7	2,185.5	363.6	20.0	2,104.6	282.7	15.5
4	2,233.9	412.0	22.6	2,233.9	412.0	22.6	2,236.2	414.3	22.7

[a] All costs are in constant 1994 dollars.

[b] Net present value with salvage value.

[c] Net present value without salvage value.

TABLE 36 Percentage of Capital Investments by Technology Type and Commitment-Level Alternative for the 12 Large Western Customers for the High-Flexibility Scenario[a]

	No Action Alternative			Alternative 2			Alternative 5			Alternative 4		
Technology Type	Total (%)	NPV[b] (%)	NPV[c] (%)	Total (%)	NPV[b] (%)	NPV[c] (%)	Total (%)	NPV[b] (%)	NPV[c] (%)	Total (%)	NPV[b] (%)	NPV[c] (%)
Pulverized coal	38.94	48.96	41.74	36.67	40.45	38.08	33.69	39.80	35.80	33.15	37.92	34.93
Coal IGCC	39.23	19.29	34.52	36.94	18.39	32.20	33.94	14.4	28.85	33.40	13.72	28.15
Combined cycle	1.24	0.70	1.10	8.52	14.21	9.84	1.62	1.76	1.63	2.12	1.58	1.94
Gas turbine	20.17	30.4	22.18	17.86	26.95	19.89	30.75	44.04	33.73	30.31	44.8	33.71
Diesel	0.42	0.64	0.46	0.00	0.00	0.00	0.00	0.00	0.00	1.03	1.99	1.27

[a] All costs are in constant 1994 dollars.

[b] Net present value with salvage value.

[c] Net present value without salvage value.

TABLE 35 Capital Investments by Technology Type and Commitment-Level Alternative for the 12 Large Western Customers for the High-Flexibility Scenario[a]

Technology Type	No Action Alternative Total Invest. (10^6)	No Action Alternative NPV[b] (10^6)	No Action Alternative NPV[c] (10^6)	Alternative 2 Total Invest. (10^6)	Alternative 2 NPV[b] (10^6)	Alternative 2 NPV[c] (10^6)
Pulverized coal	1,062.7	274.2	760.5	1,062.7	274.2	760.5
Coal IGCC[d]	1,070.5	108.0	628.9	1,070.5	124.7	643.0
Combined cycle	33.9	4.0	19.9	246.9	96.3	196.4
Gas turbine	550.5	170.2	404.1	517.7	182.6	397.3
Diesel	11.5	3.5	8.5	0.0	0.0	0.0
Total	2,729.0	559.9	1,821.9	2,900.9	681.1	2,000.4

Technology Type	Alternative 5 Total Invest. (10^6)	Alternative 5 NPV[b] (10^6)	Alternative 5 NPV[c] (10^6)	Alternative 4 Total Invest. (10^6)	Alternative 4 NPV[b] (10^6)	Alternative 4 NPV[c] (10^6)
Pulverized coal	1,062.7	298.7	780.4	1,062.7	298.7	780.4
Coal IGCC	1,070.5	108.0	628.9	1,070.5	108.0	628.9
Combined cycle	51.0	13.2	35.4	67.9	12.4	43.4
Gas turbine	969.9	330.4	735.3	971.5	352.8	753.1
Diesel	0.0	0.0	0.0	32.9	15.6	28.4
Total	3,160.4	2,186.4	2,186.4	3,210.8	792.8	2,239.3

[a] All costs are in constant 1994 dollars.

[b] Net present value with salvage value.

[c] Net present value without salvage value.

[d] IGCC = Integrated Gasification Combined Cycle.

As shown in Table 36, coal technologies account for the highest portion of total investment costs under all scenarios. However, in terms of NPV with salvage value credits, gas turbines account for up to 44% of total expenditures under Alternatives 4 and 5.

11.1.2 Fixed Costs

Because a combination of the commitment-level alternative and the operational scenario is projected to affect the capacity expansion paths of large Western customers, fixed O&M costs are also affected. Table 37 shows fixed O&M costs as a function of time and

TABLE 37 Fixed O&M Costs and Short-Term Firm Capacity Costs for the 12 Large Western Customers by Commitment-Level Alternative for the High-Flexibility Scenario[a]

Year	No Action Alternative		Alternative 2		Alternative 5		Alternative 4	
	Annual ($\$10^6$)	Cumulative ($\$10^6$)	Annual ($\$10^6$)	Cumulative ($\$10^6$)	Annual ($\$10^6$)	Cumulative ($\$10^6$)	Annual ($\$10^6$)	Cumulative ($\$10^6$)
1993	218.72	218.72	218.46	218.46	220.89	220.89	225.13	225.13
1994	219.51	438.23	222.49	472.04	221.87	442.76	225.39	450.52
1995	219.77	658.00	222.73	710.47	222.47	665.23	226.10	676.62
1996	219.91	877.92	223.26	949.47	227.45	892.68	229.73	906.35
1997	227.53	1,105.45	230.82	1,196.56	228.25	1,120.93	231.17	1,137.52
1998	227.70	1,333.15	231.14	1,348.90	229.07	1,350.00	231.40	1,368.92
1999	238.04	1,571.18	240.96	1,589.86	242.56	1,592.56	244.96	1,613.89
2000	238.33	1,809.51	241.67	1,831.53	239.66	1,832.23	241.94	1,855.83
2001	238.72	2,048.23	241.94	2,073.47	240.18	2,072.40	242.30	2,098.13
2002	254.73	2,302.96	257.99	2,331.46	256.74	2,329.14	258.13	2,356.26
2003	256.29	2,559.24	259.52	2,590.98	257.65	2,586.79	259.74	2,615.99
2004	256.34	2,815.59	259.52	2,850.51	264.00	2,850.78	266.23	2,882.22
2005	263.42	3,079.00	281.82	3,132.33	264.83	3,115.62	267.86	3,150.09
2006	277.83	3,356.83	280.91	3,413.24	279.09	3,394.71	282.12	3,432.21
2007	283.86	3,640.70	287.16	3,700.40	285.97	3,680.68	288.42	3,720.63
Annual average ($\$10^6$/yr)	242.71		246.70		245.38		248.05	
NPV ($\$10^6$/yr)	2,537.38		2,576.14		2,566.18		2,595.41	
NPV cost above No Action	0.00		38.75		28.80		58.02	
NPV above No Action (%)	0.00		1.53		1.13		2.29	

[a] Short-term firm capacity charges exclude any costs paid to Western. All costs are in constant 1994 dollars.

commitment-level alternative for the high-flexibility scenario. For modeling and cost accounting purposes, monthly capacity charges associated with non-Western purchases are also calculated. Average annual fixed O&M costs under the No Action Alternative are about $242.7 million/yr, while costs for Alternatives 2, 5, and 4 are higher at $246.8 million/yr, $245.4 million/yr, and $248.0 million/yr, respectively. Net present value costs above the No Action Alternative range from approximately $29 million for Alternative 5 to $58 million for Alternative 4. These cost differences tend to be significantly less than capital cost differences (Table 33) in terms of both absolute differences and percent differences. Alternative 2 also has higher fixed O&M costs than Alternative 5. For some utility systems, reductions in Western LTF energy (i.e., Alternative 2) are more costly than losses in LTF capacity (i.e., Alternative 5).

An examination of capacity expansion requirements (Table 24) and total O&M costs (Table 37) shows that incremental fixed O&M costs vary among commitment-level alternatives. To estimate the cost of reductions in SLCA capacity allocations during the 15-year contract period, changes in Western LTF capacity commitments to the large customers are compared with changes in the NPV of fixed O&M costs. In terms of the NPV over the 15-year contract, reductions in Western LTF capacity increase fixed O&M costs by approximately $49/kW under Alternative 5 and $90/kW under Alternative 4. These costs equate to incremental annual fixed payments above the No Action Alternative of $4.7 and $8.5/kW-yr for Alternatives 5 and 4, respectively. Because of a lack of data for Deseret, the level of uncertainty is higher regarding cost estimates made for this system. Therefore, incremental annual fixed payments above the No Action Alternative were computed without Deseret. For Alternatives 5 and 4, incremental costs increased by about 13% to $5.2 and $9.5/kW-yr, respectively.

Differences among commitment-level alternatives would be greater if the LTF contract period was 20 years. On the basis of a 20-year contract, increases in the NPV of expenditures above the No Action Alternative are about $50 million, $36 million, and $69 million, for commitment-level Alternatives 2, 5, and 4, respectively.

Table 38 shows cost summaries as a function of both commitment-level alternative and operational scenario. Cost changes across commitment-level alternatives are relatively small (i.e., less than a 2.5% change). For a given commitment-level alternative, cost changes by less than 0.6% across operational scenarios. Total costs under Alternative 2 are identical under all operational scenarios, and under Alternative 4, costs vary by approximately $0.1 million. Alternative 5 has the highest level of variability across operational scenarios. In terms of the NPV, the medium-flexibility case is more than $10.3 million and $11.1 million more expensive than the high-flexibility and low-flexibility scenarios, respectively. Although under Alternative 5, fewer capacity additions are required under the medium-flexibility scenarios than under the other two operational scenarios (Table 29), O&M costs are higher because units built under the medium-flexibility scenario have higher fixed O&M costs.

TABLE 38 Net Present Value Expenditures for Fixed O&M Costs and Short-Term Firm Capacity Charges by Commitment-Level Alternative and Operational Scenario for the 12 Large Western Customers[a]

	Hydropower Operational Scenario								
	High Flexibility			Medium Flexibility			Low Flexibility		
Marketing Alternative	Total Invest. ($\$10^6$)	Change ($\$10^6$)	Change (%)	Total Invest. ($\$10^6$)	Change ($\$10^6$)	Change (%)	Total Invest. ($\$10^6$)	Change ($\$10^6$)	Change (%)
No Action	3,640.7	0.0	0.0	3,642.6	1.9	0.1	3,642.6	1.9	0.1
2	3,700.3	59.6	1.6	3,700.3	59.6	1.6	3,700.3	59.6	1.6
5	3,680.7	40.0	1.1	3,699.1	58.4	1.6	3,679.4	38.8	1.1
4	3,720.6	80.0	2.2	3,720.6	80.0	2.2	3,720.7	80.1	2.2
	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)
No Action	2,537.4	0.0	0.0	2,538.6	1.2	0.1	2,538.6	1.2	0.1
2	2,576.2	38.8	1.5	2,576.2	38.8	1.5	2,576.2	38.8	1.5
5	2,566.2	28.8	1.1	2,576.5	39.1	1.5	2,565.3	27.9	1.1
4	2,595.4	58.0	2.3	2,595.4	58.0	2.3	2,595.4	58.0	2.3

[a] Short-term firm capacity charges exclude any costs paid to Western. All costs are in constant 1994 dollars.

11.1.3 Generation Costs

Because Western LTF contracts serve a significant portion of the loads of several Western customers, reductions in LTF contracts will require changes in the dispatch of customers' electric generating resources. Western LTF energy commitments to large customers are approximately 2,224 MWh/yr lower under Alternatives 2 and 4 than they are under the No Action Alternative (Table 25). Under Alternative 5, LTF energy commitments are 360 MWh/yr lower. Table 39 shows generation costs as a function of time and commitment-level alternative under the high-flexibility scenario. Generation costs include fuel, plant variable O&M costs, and unserved energy costs. Costs shown in the table were estimated by the ICARUS dispatch module and are based on the assumption that each utility system operates in isolation and generates electricity to serve loads that are not served through LTF purchase contracts. Each system also generates electricity to honor its LTF sales contracts. Because systems are modeled in isolation, it is possible that loads will not be served. Unserved energy costs were set to 64 mill/kWh. In general, unserved energy costs account for less than 0.5% of the costs shown in the table.

The NPV costs above the No Action Alternative range from approximately $582 million for Alternative 4 to $126 million for Alternative 5. These cost differences tend to be significantly more than differences in capital costs or fixed O&M costs in terms of both absolute differences and percent differences. Differences between scenarios would be approximately 25 to 30% greater if the LTF contract period was extended to 20 years. On the basis of 20 years, increases in NPV of expenditures are about $653 million, $166 million, and $749 million, for Alternatives 2, 5, and 4, respectively.

Cumulative variable costs above the No Action Alternative are approximately $735 million, $183 million, and $840 million for Alternatives 2, 5, and 4, respectively. Therefore, reductions in Western LTF energy below the No Action Alternative cost approximately 22.1 mill/kWh for Alternative 2. Replacement energy costs are slightly higher at 25.2 mill/kWh for Alternative 4 and increase significantly to 33.9 mill/kWh under Alternative 5. Differences in replacement energy costs are partially attributed to the amount of discretionary LTF energy sold to customers; that is, energy replacement costs increase as discretionary energy is reduced (Table 10). Note the dramatic increase in replacement costs — from 25.2 to 33.9 mill/kWh — between Alternatives 4 and 5, although significantly more LTF energy is sold under Alternative 5. This cost increase is significantly higher than the increase between Alternatives 2 and 4 — from 22.1 to 25.2 mill/kWh. This suggests that at some point below the 794.6-GWh discretionary energy level, replacement costs increase rapidly. Differences in replacement energy costs can also be attributed to changes in capacity expansion paths. In general, the capacity expansion paths that build units with relatively high operating costs tend to increase the cost of replacing Western LTF energy. As shown in Tables 27 and 28, under Alternatives 4 and 5, more gas turbines with high operating costs are constructed.

TABLE 39 Generating Costs for the 12 Large Western Customers by Commitment-Level Alternative for the High-Flexibility Scenario, Assuming Isolated Systems[a]

	No Action Alternative		Alternative 2		Alternative 5		Alternative 4	
Year	Annual (10^6)	Cumulative (10^6)	Annual (10^6)	Cumulative (10^6)	Annual (10^6)	Cumulative (10^6)	Annual (10^6)	Cumulative (10^6)
1993	647.92	647.92	705.45	705.45	656.45	656.45	690.89	690.89
1994	669.96	1,317.88	715.28	1,420.72	681.28	1,337.73	717.74	1,408.63
1995	686.85	2,004.74	734.10	2,154.82	700.20	2,037.93	738.70	2,147.33
1996	708.23	2,712.97	755.48	2,910.30	712.48	2,750.41	752.70	2,900.03
1997	734.75	3,447.72	784.25	3,694.55	746.71	3,497.12	788.10	3,688.13
1998	770.42	4,218.13	818.19	4,512.75	784.73	4,281.85	827.72	4,515.85
1999	780.85	4,998.99	829.06	5,341.81	794.85	5,076.70	837.62	5,353.47
2000	828.50	5,827.49	880.04	6,221.84	840.89	5,917.58	885.28	6,238.76
2001	885.60	6,713.09	940.67	7,162.51	899.92	6,817.50	947.31	7,186.06
2002	862.52	7,575.62	913.51	8,076.02	876.73	7,694.23	923.04	8,109.10
2003	905.57	8,481.19	961.69	9,037.72	919.23	8,613.46	966.62	9,075.72
2004	945.57	9,426.76	1,002.67	10,040.39	944.04	9,557.50	992.08	10,067.80
2005	990.70	10,417.46	985.40	11,025.79	1,007.05	10,564.55	1,056.05	11,123.84
2006	975.45	11,392.91	1,039.39	12,065.18	992.11	11,556.66	1,039.71	12,163.56
2007	1,017.00	12,409.91	1,080.63	13,145.80	1,036.34	12,593.00	1,086.41	13,249.96
Average (10^6/yr)	827.33		876.39		839.53		883.33	
NPV (10^6/yr)	8,536.47		9,059.52		8,662.55		9,118.40	
NPV above No Action (10^6)	0.0		523.06		126.08		581.93	
NPV above No Action (%)	1.00		6.13		1.48		6.82	
Replacement energy cost (mill/kWh)	NA		22.05		33.93		25.16	

[a] All costs are in constant 1994 dollars.

Replacement energy costs are significantly higher than average production costs for Western's large customers in 1993. Assuming isolated systems, average production costs in 1993 are estimated to be approximately 17.1 mill/kWh under the No Action Alternative. This average cost estimate is higher than actual production costs to serve load because utility systems purchase power when prices are lower than production costs. Production costs are also expected to increase because higher demand levels in the future will require more expensive units to operate more frequently and for longer times. (Likewise, fuel costs are expected to increase in the future.) By 2007, average production costs are expected to be approximately 21.8 mill/kWh. Other factors such as the distribution of LTF energy sales among customers, discretionary energy levels, and capacity expansion paths will also affect the relative difference between average production costs and incremental replacement costs.

Table 40 shows cost summaries as a function of both commitment-level alternative and operational scenario. Cost changes across operational scenario are significant and, in terms of NPV, vary by more than $53.5 million. For a given commitment-level alternative, changes in generation costs between operational scenarios tend to be significantly larger than changes in fixed O&M (Table 38). Also, generation costs are lower under Alternative 5 with a medium-flexibility scenario than under Alternative 5 with the other operational scenarios. These lower costs result from a capacity expansion path that has higher capital and fixed expenditures (Tables 34 and 38) and lower operating costs.

11.1.4 Large Customer Costs for Western Capacity and Energy

Western has an obligation to repay SLCA/IP construction costs related to power, interest of this investment, and the cost with interest of replacements; to recoup all O&M expenses and construction costs of participating irrigation projects; and to recover all capacity and energy purchasing costs. Power costs must be repaid regardless of Western's LTF obligations or supply resources. Western used its power repayment model to estimate energy and capacity charges under commitment-level alternatives and operational scenarios. Results of this analysis (Table 41) reveal large differences among the various combinations. Energy charge rates vary by more than a factor of 2, and capacity charge rates vary by more than a factor of 9.

Some of the utility systems under investigation may decline Western LTF contract offers when rates are relatively high. Other systems may still enter into LTF contracts to secure a reliable source of capacity but may not use all of the LTF energy allocations. Energy charges under the low-flexibility scenario are approaching estimates of energy replacement costs under Alternatives 2 and 4 (Section 11.1.3) and are higher than average generation costs in 1993. Western capacity charges are also higher than the combined capacity and fixed O&M replacement costs under several combinations of commitment-level alternative and hydropower operational scenario. As discussed in Sections 11.1.1 and 11.1.2, combined capacity and fixed O&M replacement costs are approximately $2.1 to $3.7/kW-month. Because the difference among Western large customers is relatively large, some utility

TABLE 40 Net Present Value Expenditures for Generating Costs by Commitment-Level Alternative and Operational Scenario for the 12 Large Western Customers, Assuming Isolated Systems[a]

	Hydropower Operational Scenario								
	High Flexibility			Medium Flexibility			Low Flexibility		
Marketing Alternative	Total Invest. ($\$10^6$)	Change ($\$10^6$)	Change (%)	Total Invest. ($\$10^6$)	Change ($\$10^6$)	Change (%)	Total Invest. ($\$10^6$)	Change ($\$10^6$)	Change (%)
No Action	12,410.1	0.0	0.0	12,436.6	26.5	0.2	12,465.1	55.0	0.4
2	13,145.7	735.6	5.9	13,136.2	726.1	5.9	13,217.5	807.4	6.5
5	12,592.8	182.7	1.5	12,507.0	96.9	0.8	12,560.7	150.6	1.2
4	13,250.0	839.9	6.8	13,248.5	838.4	6.8	13,326.0	915.9	7.4
	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)
No Action	8,536.5	0.0	0.0	8,554.0	17.6	0.2	8,573.8	37.4	0.4
2	9,059.5	523.0	6.1	9,053.6	517.2	6.1	9,108.8	572.3	6.7
5	8,662.6	126.1	1.5	8,612.4	75.9	0.9	8,640.6	104.2	1.2
4	9,118.4	581.9	6.8	9,117.3	580.9	6.8	9,170.3	633.8	7.4

[a] All costs are in constant 1994 dollars.

TABLE 41 Western Long-Term Firm Energy and Capacity Charges by Commitment-Level Alternative and Operational Scenario[a]

	Hydropower Operational Scenario					
	High Flexibility		Medium Flexibility		Low Flexibility	
Commitment-Level Alternative	Energy Charge ($/MWh)	Capacity Charge ($/MW-month)	Energy Charge ($/MWh)	Capacity Charge ($/MW-month)	Energy Charge ($/MWh)	Capacity Charge ($/MW-month)
No Action	10.91	3.981	12.04	4.396	20.25	7.393
2	7.64	1.451	12.79	2.428	20.22	3.838
5	11.63	8.487	14.59	10.652	18.40	13.434
4	7.69	3.815	9.37	4.650	14.70	7.297

[a] All costs are in constant 1994 dollars.

systems are significantly higher than the average replacement value, while others are significantly lower. Energy replacement estimates are also somewhat high because of the assumption of isolated systems.

It was beyond the scope of this analysis to determine which customers would continue to enter into Western contracts under various rate structures. In addition, any capacity and energy not received by a customer would have to be sold elsewhere. Because the distribution of existing Western LTF contracts is not strictly based on a cost minimization objective, an LTF contract to a new customer or higher allocations to existing customers may distort results. For example, if a large customer with low costs declined a Western LTF contract and it was sold to another utility system with very high short- and long-run marginal costs, a low-capacity, low-energy alternative could result in lower overall costs than the No Action Alternative.

Table 42 shows expenses, in terms of the NPV, for large LTF customers. The table shows that for any given commitment-level alternative and operational scenario, capacity expenditures approximately equal energy expenditures. Also, expenditures increase as hydropower plant operational flexibility decreases; that is, although customers receive an identical product under a given commitment-level alternative, they pay more when Western's hydropower plant operational flexibility is reduced. Relative to the No Action Alternative with high operational flexibility, the money paid by large customers increases by as much as 85% under the No Action Alternative with low operational flexibility and decreases by as much as 60% under Alternatives 2 and 4 with high operational flexibility. Although the value of the Western LTF contract to the customer is significantly reduced, under Alternative 5 large customers pay slightly more than under the No Action Alternative.

TABLE 42 Summary of Expenditures by the 12 Large Customers for Western Long-Term Firm Energy and Capacity by Commitment-Level Alternative and Operational Scenario[a]

Commitment-Level Alternative	Hydropower Operational Scenario								
	High Flexibility			Medium Flexibility			Low Flexibility		
	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)	NPV ($\$10^6$)	Change ($\$10^6$)	Change (%)
Western Energy Costs									
No Action	585.8	0.0	0.0	646.7	60.9	-10.4	1,087.5	501.7	85.7
2	229.5	-356.3	-60.8	384.1	-201.7	-34.4	607.2	21.4	3.7
5	579.1	-6.6	-1.1	726.9	141.1	24.1	916.8	331.0	56.5
4	230.8	-355.0	-60.6	281.2	-304.6	-52.0	441.4	-144.4	-24.7
Western Capacity Costs									
No Action	567.5	0.0	0.0	626.6	59.1	10.4	1,053.8	486.3	85.7
2	229.8	-337.6	-59.5	384.6	-182.8	-32.2	575.8	8.3	1.5
5	579.6	12.1	2.1	727.3	159.8	28.2	917.3	349.8	61.7
4	230.7	-336.8	-59.4	279.4	-288.1	-50.8	438.5	-129.0	-22.7

[a] All costs are in constant 1994 dollars.

11.1.5 Isolated Utility Systems Cost Summary

Total costs as a function of commitment-level alternative and operational scenario are summarized in Table 43. Except for Western LTF purchase costs, all other cost components are projected to be higher than those of the No Action Alternative with a high operational flexibility. However, savings for Western LTF purchases can be significant and exceed $693 million. Because of these large savings, Alternative 2 with high operational flexibility has lower total costs than those of the No Action Alternative with high operational flexibility. In general, Alternative 5 has large increases in total costs, ranging from about $350 million under the high-flexibility scenario to approximately $975 million under the low-flexibility scenario. However, because of large increases in Western LTF purchase costs, the No Action Alternative under the low-flexibility scenario has the highest overall cost increase ($1,074 million). Under all commitment-level alternatives, total costs increase as operational flexibility decreases. Total cost patterns are significantly influenced by Western LTF purchase costs, which exhibit large changes across both commitment-level alternative and operational scenario.

Combined costs for capital, fixed O&M, and generation are the highest for Alternative 4, when Western LTF purchases of both capacity and energy are low. Although the amount of Western LTF energy is the same for both Alternatives 2 and 4, generation costs for Alternative 2 are $59 million lower. Alternative 2 has significantly higher levels of both discretionary energy and capacity (Tables 4 and 9), which allows large customers to reduce generation costs by purchasing most of the LTF energy during on-peak periods.

In terms of percentage, total costs are projected to increase by a maximum of 8.4%. This increase is based on only a portion of utility costs; that is, costs for transmission and distribution, billing, administration, dispatching, and other expenditures are not included. Likewise, revenues from LTF sales to other systems are not included. Incorporating these costs and revenues could significantly affect the percent changes in costs and does not reflect percent changes in rates that large customers would charge retail customers. A detailed analysis of customer rate changes that includes the previously mentioned cost components is documented in Bodmer et al. (1995).

11.1.6 Connected Systems

The 12 large Western customers do not operate in isolation, and significant amounts of energy are traded on the spot market. The effects of commitment-level alternative and operational scenario on spot market activities were discussed in Section 10. In addition, during wet hydropower conditions, Western sells STF energy to its firm customers. Table 44 shows NPV costs and revenues as a function of commitment-level alternative and operational scenario. Generation costs shown in the table are based on SMN simulations. Where applicable, costs have been weighted by hydropower probability for wet, normal, and dry conditions. Probabilities were estimated by using the methodology described in Section 6.1.

TABLE 43 Summary of Net Present Value of Costs for the 12 Large Western Customers, Assuming Isolated Systems[a]

	Hydropower Operational Scenario								
	High Flexibility			Medium Flexibility			Low Flexibility		
Commitment-Level Alternative/Cost Component	Net Present Value ($\$10^6$)	Increase ($\$10^6$)	Increase (%)	Net Present Value ($\$10^6$)	Increase ($\$10^6$)	Increase (%)	Net Present Value ($\$10^6$)	Increase ($\$10^6$)	Increase (%)
No Action									
Capital costs	559.9	0.0	0.0	607.4	47.5	8.5	607.4	47.5	8.5
Fixed O&M costs	2,537.4	0.0	0.0	2,538.6	1.2	0.1	2,538.6	1.2	0.1
Generation costs	8,536.5	0.0	0.0	8,554.0	17.6	0.2	8,573.8	37.4	0.4
Western LTF purchases	1,153.2	0.0	0.0	1,273.3	120.0	10.4	2,141.3	988.1	85.7
Total costs	12,787.0	0.0	0.0	12,973.3	186.3	1.5	13,861.2	1,074.1	8.4
Alternative 2									
Capital costs	677.8	118.0	21.1	677.8	118.0	21.1	677.8	118.0	21.1
Fixed O&M costs	2,576.2	38.8	1.5	2,576.2	38.8	1.5	2,576.2	38.8	1.5
Generation Costs	9,059.5	523.0	6.1	9,053.6	517.2	6.1	9,108.8	572.3	6.7
Western LTF purchases	459.4	-693.9	-60.2	768.7	-384.5	-33.3	1,215.1	61.9	5.4
Total costs	12,772.9	-14.1	-0.1	13,076.4	289.4	2.3	13,577.9	790.9	6.2
Alternative 5									
Capital costs	750.2	190.3	34.0	768.7	208.9	37.3	721.9	162.1	29.0
Fixed O&M costs	2,566.2	28.8	1.1	2,576.5	39.1	1.5	2,565.3	27.9	1.1
Generation costs	8,662.6	126.1	1.5	8,612.4	75.9	0.9	8,640.6	104.2	1.2
Western LTF purchases	1,158.7	5.5	0.5	1,454.2	300.9	26.1	1,834.1	680.8	59.0
Total costs	13,137.7	350.7	2.7	13,411.8	624.7	4.9	13,762.0	975.0	7.6
Alternative 4									
Capital costs	787.5	227.6	40.7	787.5	227.6	40.7	790.4	230.5	41.2
Fixed O&M costs	2,595.4	58.0	2.3	2,595.4	58.0	2.3	2,595.4	58.0	2.3
Generation costs	9,118.4	581.9	6.8	9,117.3	580.9	6.8	9,170.3	633.8	7.4
Western LTF purchases	461.5	-691.8	-60.0	560.6	-592.6	-51.4	879.8	-273.4	-23.7
Total costs	12,962.8	175.8	1.4	13,060.8	273.8	2.1	13,436.0	648.9	5.1

[a] All costs are in constant 1994 dollars.

TABLE 44 Summary of Net Present Value of Costs and Revenues for the 12 Large Western Customers, Assuming Connected Systems[a]

	Hydropower Operational Scenario					
	High Flexibility		Medium Flexibility		Low Flexibility	
Commitment-Level Alternative/Cost Component	NPV ($\$10^6$)	Increase ($\$10^6$)	NPV ($\$10^6$)	Increase ($\$10^6$)	NPV ($\$10^6$)	Increase ($\$10^6$)
No Action						
Capital costs	559.9	0.0	607.4	47.5	607.4	47.5
Fixed O&M costs	2,537.4	0.0	2,538.6	1.2	2,538.6	1.2
Generation costs	8,860.3	0.0	8,875.3	15.0	8,905.3	45.0
Western LTF purchases	1,153.2	0.0	1,273.3	120.0	2,141.3	988.1
Western STF purchases	35.3	0.0	37.8	2.5	72.5	37.1
Spot market purchases	793.2	0.0	767.5	–25.7	755.8	–37.5
Spot market sales	1,875.0	0.0	1,880.1	5.1	1,910.1	35.1
Total net costs	12,064.4	0.0	12,219.8	155.3	13,110.7	1,046.3
Alternative 2						
Capital costs	677.8	118.0	677.8	118.0	677.8	118.0
Fixed O&M costs	2,576.2	38.8	2,576.2	38.8	2,576.2	38.8
Generation costs	8,843.2	–17.1	8,867.8	7.5	8,892.4	32.1
Western LTF purchases	459.4	–693.9	768.7	–384.5	1,215.1	61.9
Western STF purchases	84.0	48.7	142.7	107.4	224.5	189.2
Spot market purchases	851.0	57.8	820.0	26.8	824.3	31.0
Spot market sales	1,665.7	–209.3	1,678.2	–196.8	1,707.8	–167.2
Total net costs	11,825.9	–238.5	12,175.0	110.6	12,702.6	638.1
Alternative 5						
Capital costs	750.2	190.3	768.7	208.9	721.9	162.1
Fixed O&M costs	2,566.2	28.8	2,576.5	39.1	2,565.3	27.9
Generation costs	8,859.2	–1.1	8,892.4	32.1	8,910.6	50.3
Western LTF purchases	1,158.7	5.5	1,454.0	300.7	1,834.1	680.8
Western STF purchases	0.0	–35.3	0.0	–35.3	0.0	–35.3
Spot market purchases	919.6	126.3	865.0	–71.7	855.3	62.1
Spot market sales	1,842.0	–33.0	1,829.6	–45.4	1,842.3	–32.7
Total net costs	12,411.9	347.5	12,727.0	662.5	13,045.0	980.6
Alternative 4						
Capital costs	787.5	227.6	787.5	227.6	790.4	230.5
Fixed O&M costs	2,595.4	58.0	2,595.4	58.0	2,595.4	58.0
Generation costs	8,857.1	–3.2	8,878.5	18.2	8,899.9	39.6
Western LTF purchases	461.5	–691.8	560.6	–592.6	879.8	–273.4
Western STF purchases	41.7	6.4	52.2	16.9	75.5	40.1
Spot market purchases	1,068.4	275.1	1,036.2	243.0	1,028.8	235.5
Spot market sales	1,648.9	–226.1	1,645.9	–229.1	1,661.0	–214.0
Total net costs	12,162.7	98.3	12,264.6	200.2	12,608.8	544.3

[a] Spot market transactions are the sum of the 12 individual large customers, *not* the net among the large customers. All costs are in constant 1994 dollars.

Several cost components do not change from the isolated system case summarized in Table 43. These cost components include capital, fixed O&M, and Western LTF purchases. It is assumed that long-term capacity expansion plans are not significantly influenced by speculations about future spot market activities.

Although the connected system analysis is significantly more detailed than the isolated system analysis in several modeling aspects, total net cost trends and magnitudes shown in Table 44 are similar to the isolated systems analysis shown in Table 43. However, several subtle differences can be observed for individual cost components. For example, generation cost in the isolated systems analysis vary significantly across commitment-level alternatives and operational scenarios. However, in the connected systems analysis, generating costs show much less variation (i.e., about $70 million vs. about $642 million). This fact is due to both STF energy purchases from Western and adjustments to spot market activities. When Western LTF allocations decrease, Western STF purchases increase; spot market sales tend to decrease, and spot market purchases tend to increase. Some of this increase in spot market purchases is attributed to higher non-firm energy purchases from Western. When Western LTF energy sales decrease, sales shift to STF energy and spot market sales.

Another reason for the relatively small variations in generation costs is that many of the large Western customers have generators with relatively low variable O&M costs. When these units are available, excess capacity above loads can usually be sold on the spot market at a profit. Therefore, large low cost generators are not expected to significantly change operations, but under low Western LTF energy alternatives, more generation will be used to serve a utility's own load, and less will be available for spot market sales.

As compared with the isolated systems analysis, cost differences above the No Action Alternative with a high-flexibility scenario are generally lower. An exception to this general rule is under Alternative 5. Under the high-flexibility scenario, cost increases are about the same, but under the medium- and low-flexibility scenarios, costs are higher. Under this commitment-level alternative, large customers have no discretionary energy, which minimizes the energy that customers can sell at times of peak demand when prices are high and significantly increases spot market sales off-peak when prices are low. Under the medium- and low-flexibility scenarios, a customer's ability to purchase energy on the spot market from Western during times of peak demand is also substantially reduced.

11.2 INVESTOR-OWNED UTILITY SYSTEMS

Many investor-owned utilities in the Western SLCA commitment-level area interact with Western and Western's LTF customers. Western buys and sells to investor-owned utilities on the spot market and has the potential to sell to investor-owned systems on the STF market. Several large Western customers also have long-term agreements and engage in spot market transactions with investor-owned utilities. Therefore, changes that either affect Western or its LTF customers can affect these investor-owned systems.

11.2.1 Capital and Fixed O&M Costs

Table 45 presents consolidated investment streams and fixed O&M costs as well as the combined NPVs for the five investor-owned systems. Total capital investments are about $11,174 million, or about four times the total investments of the large Western customers. This amount translates to an average annual expenditure of about $745 million. From 1995 to 2007, capacity investments will increase at an average annual rate of about 26%. The total NPV for the combined system with salvage value is approximately $3,923 million, or about seven times that of the large Western customers.

An examination of capacity expansion requirements (Table 29) and total investment costs (Table 45) shows that average annual capital investments are approximately $1,467/kW. Assuming unit lifetimes of 35 years and a 5% real discount rate, levelized capital expenditures are $90/kW-yr. These costs are substantially higher than average costs for large Western customers. When the time value of money is incorporated into the cost calculations, average NPV expenditures for capacity are substantially lower. Taking into account the timing of capacity additions and assuming a 5% real discount rate, capital expenditures are $1,004kW. Cost calculation results are further reduced to $516/kW when credit is given for unit salvage values. This amount equates to fixed annual payments of $48/kW-yr over the 15-year study. Fixed annual payments are significantly higher (i.e., more than twice) than those of large Western customers (i.e., about $21/kW-yr) because, relative to the large Western customers, a higher portion of capital investments is made early in the study period (i.e., before 1998).

Fixed O&M costs are also higher for investor-owned utility systems. Aggregate fixed O&M costs over the 15-year contract are about $7,456 million — more than twice the total O&M costs of the large Western customers. Average annual fixed O&M expenditures are about $497 million, and the total NPV for the combined systems is approximately $5,176 million — about twice as much as the 12 large Western customers.

This analysis assumes that capacity expansion paths for investor-owned utility systems would not be altered by either Western LTF contracts or SLCA/IP hydropower plant operational restrictions. Investor-owned utility systems do not receive Western LTF capacity and energy and rarely receive Western STF capacity and energy. In addition, it is assumed that LTF contracts between Western's large customers and investor-owned utility systems would not be altered as a result of changes in SLCA LTF commitment level. As with the large Western customers, anticipated changes in spot market activities as a result of changes in SLCA LTF commitment level and operational restrictions are assumed to have little effect on capacity expansion.

11.2.2 Connected Systems Cost Summary

Total costs for investor-owned utility systems are shown in Table 46. Because under the isolated system analysis, all costs are identical across both commitment-level alternatives and operational scenarios, the table reflects costs estimated for the connected system

TABLE 45 Capital Investment and Fixed O&M Streams for the Five Investor-Owned Utilities[a]

Year	Annual Capital Investments ($\$10^6$)	Cumulative Capital Investments ($\$10^6$)	Annual Fixed O&M Costs ($\$10^6$)	Cumulative Fixed O&M Costs ($\$10^6$)
1993	0.0	0.00	433.9	433.9
1994	240.1	240.10	436.2	870.1
1995	365.0	605.10	437.6	1,307.7
1996	1,187.8	1,792.97	444.5	1,752.2
1997	721.0	2,513.96	452.9	2,205.1
1998	332.3	2,846.27	454.9	2,660.0
1999	772.0	3,618.29	467.2	3,127.1
2000	1,633.5	5,251.77	502.2	3,629.3
2001	629.1	5,880.90	515.4	4,144.8
2002	95.1	5,975.97	515.6	4,660.3
2003	1,207.8	7,183.82	532.6	5,192.9
2004	1,896.9	9,080.69	557.2	5,750.1
2005	1,149.7	10,230.39	567.8	6,317.9
2006	175.0	10,405.37	565.8	6,883.6
2007	768.6	11,174.03	572.7	7,456.4

Capital Cost Summary	
Average annual investment	745.0
Total investment	11,174.0
NPV with salvage value	5,176.3
NPV without salvage value	7,635.2
Fixed O&M Cost Summary	
Annual average	497.1
Total cost	7,456.4
NPV	5,176.3

[a] All costs are in constant 1994 dollars.

analysis. Capital and fixed O&M costs are identical for all cases, but generation costs and spot market activities vary as a function of commitment-level alternative and of operational scenario. Total net costs are also affected and tend to increase as operational flexibility decreases and Western firm capacity and energy sales to large customers decrease.

The two main driving forces that result in higher costs are (1) the amount of energy that Western customers have to sell to investor-owned utility systems and (2) the amount of energy that Western has for sale on the spot market at times of peak demand. When Western sells less energy to its large LTF customers, these utilities sell less energy on the spot market to investor-owned utility systems (Table 44). However, the less firm energy that

TABLE 46 Net Present Value of Costs and Revenues for Investor-Owned Utility Systems[a]

	Hydropower Operational Scenario					
	High Flexibility		Medium Flexibility		Low Flexibility	
Commitment-Level Alternative/Cost Component	NPV ($\$10^6$)	Increase ($\$10^6$)	NPV ($\$10^6$)	Increase ($\$10^6$)	NPV ($\$10^6$)	Increase ($\$10^6$)
No Action						
Capital costs	3,923.6	0.0	3,923.6	0.0	3,923.6	0.0
Fixed O&M costs	5,176.3	0.0	5,176.3	0.0	5,176.3	0.0
Generation costs	17,165.5	0.0	17,168.7	51.4	17,266.1	100.6
Spot market purchases	3,227.6	0.0	3,171.9	-55.7	3,152.6	-74.9
Spot market sales	2,445.3	0.0	2,434.5	-10.8	2,451.4	6.1
Total net costs	27,047.6	0.0	27,054.1	6.5	27,067.2	19.6
Alternative 2						
Fixed O&M costs	5,176.3	0.0	5,176.3	0.0	5,176.3	0.0
Generation costs	17,024.2	-141.3	17,072.3	-93.1	17,119.4	-46.0
Spot market purchases	3,240.4	12.8	3,163.3	-64.2	3,151.6	-76.0
Spot market sales	2,314.1	-131.2	2,272.8	-172.6	2,293.9	-151.5
Total net costs	27,050.4	2.8	27,062.8	15.2	27,077.0	29.4
Alternative 5						
Capital costs	3,912.9	0.0	3,923.6	0.0	3,923.6	0.0
Fixed O&M costs	5,176.3	0.0	5,176.3	0.0	5,176.3	0.0
Generation costs	17,111.9	-53.5	17,122.6	-42.8	17,166.5	1.1
Spot market purchases	3,304.6	77.1	3,247.9	20.3	3,240.4	12.8
Spot market sales	2,454.5	9.2	2,378.2	-67.1	2,411.2	-34.1
Total net costs	27,061.9	14.3	27,092.2	44.6	27,095.6	48.1
Alternative 4						
Capital costs	3,923.6	0.0	3,923.6	0.0	3,923.6	0.0
Fixed O&M costs	5,176.3	0.0	5,176.3	0.0	5,176.3	0.0
Generation costs	17,039.1	-126.3	17,062.7	-102.8	17,100.2	-65.3
Spot market purchases	3,341.0	113.5	3,228.6	1.1	3,211.5	-16.1
Spot market sales	2,400.1	-45.3	2,285.2	-160.1	2,294.7	-150.6
Total net costs	27,080.0	32.4	27,106.0	58.4	27,116.8	69.3

[a] All costs are in constant 1994 dollars.

Western sells, the more that it has available for sale on the spot market (Table 47). For example, under Alternative 2, investor-owned utilities have lower spot market sales because Western has significant sales increases under this alternative. Although large Western customers have less energy to sell under Alternatives 2 and 4, investor-owned utility systems have a slight increase in spot market purchases under the high-flexibility scenario. Investor-owned spot market purchases shifted away from the large customers toward purchases from Western. As Western's operational flexibility decreases, spot market purchase costs for investor-owned utility systems decrease because Western's ability to sell energy at times of peak demand (i.e., high prices) has diminished.

TABLE 47 Western Energy Transactions by Commitment-Level Alternative and Operational Scenario[a]

Commitment-Level Alternative/Cost Component	Hydropower Operational Scenario: High Flexibility — Average Annual Energy (GWh)	High Flexibility — Average Annual Revenue ($$10^6$)	High Flexibility — Average Price ($/MWh)	Medium Flexibility — Average Annual Energy (GWh)	Medium Flexibility — Average Annual Revenue ($$10^6$)	Medium Flexibility — Average Price ($/MWh)	Low Flexibility — Average Annual Energy (GWh)	Low Flexibility — Average Annual Revenue ($$10^6$)	Low Flexibility — Average Price ($/MWh)
No Action									
LTF sales	5,701.7	62.20	10.9	5,701.7	68.66	12.0	5,701.7	115.49	20.2
STF sales	357.3	3.90	10.9	347.5	4.19	12.0	396.8	8.04	20.2
Project use	285.1	3.12	10.9	285.1	3.44	12.0	285.1	5.77	20.2
Spot sales	1,010.0	30.72	30.4	394.0	9.85	25.0	605.0	13.62	22.5
Purchases[b]	1,436.0	32.79	22.8	842.0	22.57	26.8	1,084.0	32.47	30.0
Alternative 2									
LTF sales	3,300.0	25.22	7.6	3,300.0	42.22	12.8	3,300.0	66.74	20.2
STF sales	1,226.1	9.37	7.6	1,246.7	15.95	12.8	1,239.3	25.06	20.2
Project use	285.1	2.18	7.6	285.1	3.65	12.8	285.1	5.77	20.2
Spot sales	1,506.0	45.68	30.3	1,373.0	33.38	24.3	1,758.0	40.56	23.1
Purchase	313.0	7.88	25.2	194.0	6.31	32.5	559.0	17.68	31.7
Alternative 5									
LTF sales	5,475.0	63.65	11.7	5,475.0	79.88	14.6	5,475.0	100.76	18.4
STF sales	0.0	0.00	0.0	0.0	0.00	0.0	0.0	0.00	0.0
Project use	285.1	3.32	11.7	285.1	4.16	14.6	285.1	5.25	18.4
Spot sales	1,929.0	60.93	31.6	1,030.0	28.80	27.9	796.0	19.14	24.1
Purchases	1,753.0	38.72	22.1	854.0	19.22	22.5	620.0	16.16	26.1
Alternative 4									
LTF sales	3,300.0	25.36	7.7	3,300.0	30.92	9.4	3,300.0	48.50	14.7
STF sales	593.1	4.56	7.7	612.3	5.74	9.4	559.6	8.22	14.7
Project use	285.1	2.19	7.7	285.1	2.67	9.4	285.1	4.19	14.7
Spot sales	2,662.0	82.91	31.2	1,918.0	54.69	28.5	1,924.0	48.99	25.5
Purchases	804.0	18.50	23.0	52.0	1.19	22.8	24.0	0.82	34.4

[a] All costs are in constant 1994 dollars.

[b] Includes both firm and non-firm spot market purchases.

Compared with the large Western customers, cost increases above the No Action Alternative with high operational flexibility are small. The maximum cost increase for the investor-owned systems is about $70 million — an increase of about 0.25%. This cost increase, however, may be offset by potential increased investor-owned utility sales to small SCLA customers. Investor-owned systems are alternative suppliers of energy and capacity for many of SLCA small customers.

11.3 WESTERN'S SLCA OFFICE

Western's energy transactions as a function of commitment-level alternative and operational scenario are shown in Table 47. Energy transactions are average values from 1993 to 2007 and are weighted by hydropower probability for wet, normal, and dry conditions. The table also provides average energy revenues and average annual energy prices or charge rates. Table 47 shows that for a commitment-level alternative, average spot market sale prices decrease as operational flexibility decreases. This occurs because as operational flexibility is reduced, Western increasingly sells on the spot market during shoulder and off-peak periods (Sections 6.2-6.6). Also, spot market sales prices are higher under Alternatives 4 and 5, where LTF capacity commitments are relatively low. Low LTF capacity commitments allow Western to sell more energy on the spot market during on-peak hours. Table 47 also shows that energy purchase prices increase as flexibility is reduced. When operational restrictions and physical constraints do not allow Western to meet its firm obligations, Western is required to make purchases to fulfill its firm commitments. Under any given operational scenario, the more stringent the operational restrictions, the more often Western is required to make these purchases during shoulder and on-peak periods. Average spot market sales prices are higher than average purchases prices under all high-flexibility scenarios and for Alternatives 4 and 5 (i.e., low LTF commitments) with medium flexibility. Under other alternatives and operational scenarios, Western must buy at relatively higher prices and sell at a lower price.

Table 48 shows the NPV of Western's revenues and costs by commitment-level alternative and operational scenario. It was assumed that funds collected for project use are based on LTF energy rates and that Western would purchase capacity at $193/kW-yr. This capacity charge rate is consistent with assumptions made under studies conducted for the Glen Canyon EIS. Western's net revenue (i.e., sales-purchases) varies significantly across commitment-level alternative and operational scenario, ranging from a minimum of $100 million to a maximum of $2,004 million. An LTF capacity charge rate of $193/kWh is a reasonable estimate based on current LTF contracts (Section 11.4); however, because of its extensive transmission capabilities, Western may be able to enter into an LTF contract at significantly lower costs. Western may also be able to avoid purchasing LTF capacity for several years by purchasing an STF energy contract with zero capacity charges. Western is currently considering several firm energy contracts.

Table 48 shows that spot market sales revenues are less than purchase costs under the No Action Alternative with high flexibility for two reasons. First, during wet periods,

TABLE 48 Net Present Value of Western's Revenues and Costs for All Customers by Commitment-Level Alternative and Operational Scenario, Assuming Long-Term Firm Capacity Purchases at $193/kW-yr[a]

	Hydropower Operational Scenario								
	High Flexibility			Medium Flexibility			Low Flexibility		
Commitment-Level Alternative/Cost Component	Capacity Charges ($\$10^6$)	Energy Sales ($\$10^6$)	Total Revenue ($\$10^6$)	Capacity Charges ($\$10^6$)	Energy Sales ($\$10^6$)	Total Revenue ($\$10^6$)	Capacity Charges ($\$10^6$)	Energy Sales ($\$10^6$)	Total Revenue ($\$10^6$)
No Action									
LTF and project use	688.8	692.1	1,380.8	760.5	764.0	1,524.5	1,284.8	1,228.2	2,513.1
STF sales	0.0	40.4	40.4	0.0	43.4	43.4	0.0	83.2	83.2
Spot sales[b]	NA[c]	309.1	309.1	NA	101.3	101.3	NA	142.8	142.8
Purchases[b]	0.0	334.3	334.3	698.7	229.3	928.0	1,586.4	331.9	1,918.2
Total	688.8	707.2	1,395.9	61.8	679.3	741.1	-301.6	1,122.4	820.9
Alternative 2									
LTF and project use	282.3	289.7	572.0	472.5	484.8	957.3	747.0	766.3	1,513.4
STF sales	0.0	99.9	99.9	0.0	169.5	169.5	0.0	266.4	266.4
Spot sales[b]	NA	466.7	466.7	NA	347.7	347.7	NA	424.2	424.2
Purchase[b]	241.2	76.8	317.9	1,053.1	62.9	1,116.0	1,924.2	180.1	2,104.3
Total	41.1	779.5	820.6	-580.5	939.0	358.5	-1,177.2	1,277.0	99.8
Alternative 5									
LTF and project use	758.2	709.5	1,467.8	951.6	890.4	1,842.0	1,200.2	1,123.1	2,323.3
STF sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Spot sales[b]	NA	610.5	610.5	NA	303.9	303.9	NA	209.9	209.9
Purchases[b]	0.0	395.4	395.4	0.0	197.4	197.4	365.0	164.5	529.6
Total	758.2	924.6	1,682.8	951.6	997.0	1,948.5	835.2	1,168.5	2,003.7
Alternative 4									
LTF and project use	306.1	291.3	597.3	370.9	355.0	725.9	582.0	557.0	1,139.0
STF sales	0.0	49.1	49.1	0.0	61.7	61.7	0.0	89.0	89.0
Spot sales[b]	NA	844.7	844.7	NA	563.4	563.4	NA	507.5	507.5
Purchases[b]	0.0	184.6	184.6	0.0	11.6	11.6	96.8	7.9	104.7
Total	306.1	1,000.6	1,306.7	370.9	968.5	1,339.4	485.3	1,145.5	1,630.8

[a] All costs are in constant 1994 dollars.

[b] Purchase and sales do not include monies collected and expended for sales for resale transactions.

[c] NA denotes not applicable.

Western sells energy on the STF market, thus making less energy available for spot market sales. Second, the energy available from SLCA/IP hydropower plants on average exceeds LTF commitments under the No Action Alternative. This deficit is higher for near-term years (i.e., the next five years) because of current low reservoir conditions. Costs incurred in the first years of the study have a greater influence on the net present value calculation than those incurred in later years.

11.4 COST SUMMARY BY SYSTEM TYPE

The NPV of costs for large Western customers and investor-owned utility systems is shown in Table 49, which also contains net revenues for the Western's SLCA office. Western's revenues from firm sales include only those funds collected from large customers. Western's LTF capacity purchase costs have also been proportionately adjusted to reflect the capacity needed to serve large customers. Large customers account for approximately 86% of LTF capacity sales. Table 49 reflects an LTF purchase cost of $193/kW-yr.

Relative to the No Action Alternative under the high-flexibility scenario, total net costs for all alternatives and operational scenarios are higher. Changes in total net costs are primarily the result of (1) increases in capital expenditures by Western customers to acquire additional capacity to lower SLCA LTF capacity and energy allocations, (2) increased fixed O&M expenditures for Western customers due to changes in capacity expansion paths, (3) reductions in the value of SLCA/IP hydropower plant energy to regional energy markets due to decreases in hydropower plant operational flexibility, and (4) costs for the replacement of SLCA/IP hydropower plant capacity due to operational constraints.

In general, costs are higher for both investor-owned systems and large customers; however, large Western customers have lower costs under Alternative 2 with high flexibility. Costs for investor-owned systems are slightly higher under all commitment-level alternatives and operational scenarios. For a given operational scenario, costs for large customers, investor-owned utilities, and total net costs increase as operational flexibility decreases.

The NPV of total generation costs relative to the high-flexibility scenario increases by approximately $43 million to $70 million when medium-flexibility restrictions are imposed on SLCA/IP hydropower plants. Generation costs increase by an additional $64 million to $75 million when operations are further reduced under the low-flexibility scenario. Generation cost increases as a function of hydropower operational stringency are larger when Western LTF capacity commitments are high (i.e., under the No Action Alternative and Alternative 2). Whereas increases in generation costs account for up to $145 million of the total net costs, the remaining increases (i.e., up to $1,649 million) are mainly attributed to increases in capital expenditures for the construction of additional capacity and for Western's purchase of LTF capacity.

Alternative 2 has the highest total net costs under each of the operational scenarios. The No Action Alternative and Alternative 2 have relatively large increases in total net costs

TABLE 49 Summary of Net Present Value of Costs and Revenues by Utility Type, Assuming Western Capacity Purchases at $193/kW-yr[a]

Commitment-Level Alternative/ Utility Type	Hydropower Operational Scenario: High Flexibility: Net Present Value ($\$10^6$)	High Flexibility: Increase ($\$10^6$)	High Flexibility: Increase (%)	Medium Flexibility: Net Present Value ($\$10^6$)	Medium Flexibility: Increase ($\$10^6$)	Medium Flexibility: Increase (%)	Low Flexibility: Net Present Value ($\$10^6$)	Low Flexibility: Increase ($\$10^6$)	Low Flexibility: Increase (%)
No Action									
Large customers costs	12,064.4	0.0	0.0	12,219.8	155.3	1.3	13,110.7	1,046.3	8.7
Investor-owned costs	27,047.6	0.0	0.0	27,054.1	6.5	0.0	27,067.2	19.6	0.1
Western net revenue	1,163.3	0.0	0.0	573.5	-589.8	-50.7	641.3	-522.0	-44.9
Total net costs	37,948.7	0.0	0.0	37,629.9	751.7	2.0	39,536.6	1,587.9	4.2
Alternative 2									
Large customers costs	11,825.9	-238.5	-2.0	12,175.0	110.6	0.9	12,702.6	638.1	5.3
Investor-owned costs	27,050.4	2.8	0.0	27,062.8	15.2	0.1	27,077.0	29.4	0.1
Western net revenue	726.9	-436.4	-37.5	294.8	-868.5	-74.7	36.7	-1,126.6	-96.8
Total net costs	38,149.4	200.7	0.5	38,943.0	994.3	2.6	39,742.8	1,794.2	4.7
Alternative 5									
Large customers costs	12,411.9	347.5	2.9	12,727.0	662.5	5.5	13,045.0	980.6	8.1
Investor-owned costs	27,061.9	14.3	0.1	27,092.2	44.6	0.2	27,095.6	48.1	0.2
Western net revenue	1,373.8	210.5	18.1	1,560.7	397.4	34.2	1,567.0	403.7	34.7
Total net costs	38,100.1	151.4	0.4	38,258.5	304.8	0.8	38,573.6	625.0	1.7
Alternative 4									
Large customers costs	12,162.7	98.3	0.8	12,264.6	200.2	1.7	12,608.8	544.3	4.5
Investor-owned costs	27,080.0	32.4	0.1	27,106.0	58.4	0.2	27,116.8	69.3	0.3
Western net revenue	1,163.4	0.1	0.0	1,164.8	1.5	0.1	1,371.1	207.8	17.9
Total net costs	38,079.3	130.6	0.3	38,205.8	257.1	0.7	38,354.5	405.8	1.1

[a] All costs are in constant 1994 dollars.

as operational flexibility decreases. These cost increases are largely attributed to the cost of Western LTF capacity purchases. As shown in Table 16, under the No Action Alternative, Western is required to purchase LTF capacity under both the medium- and low-flexibility scenarios. Western LTF capacity purchases are required under all operational scenarios for Alternative 2. Total net costs as a function of operational flexibility increase significantly less under Alternatives 4 and 5 because relatively small Western LTF purchases for these two scenarios are only required under the low-flexibility scenario.

Because Western LTF purchases account for much of the increase in total costs, a sensitivity analysis was performed on this assumption. Although this LTF capacity cost appears to be a reasonable assumption based on current LTF contracts, it most likely does not reflect the economic value or (i.e., marginal cost of capacity additions) to the 17 utility systems under investigation. That is, at an LTF capacity cost of $193/kW-yr, the seller of the capacity may make a profit. This profit should be subtracted from the total cost computation to estimate the net economic costs to the combined utility systems. Results of the sensitivity analysis are provided in Table 50.

Although a detailed analysis was not conducted to specifically compute profits for LTF capacity sale, increased capital and fixed O&M costs for large Western customers provide an estimate of the marginal cost of capacity expansion during the 15-year contract period. As detailed in Sections 11.1.1 and 11.1.2, the combined increase in expenditures for capital and fixed O&M costs to replace reductions in Western LTF contracts (i.e., a noncontingent contract) is approximately $35 to $43/kW-yr. This incremental cost is increased to as high as $47/kW-yr if Deseret is excluded from the incremental cost analysis. Relatively low incremental costs are attributed to a current regional capacity excess, most of which is base-load cost units. Also, capacity additions above the No Action Alternative are expected to be predominately gas technologies with relatively low capital and O&M costs. Another contributing factor is the short contract period. As discussed in Section 9, not all of the LTF capacity reductions are replaced with capacity additions at the end of 15 years. Incremental capacity costs would be about 30% higher if the contract period were extended from 15 to 20 years.

Although incremental costs are significantly less than the $193/kW-yr LTF purchase cost, incremental capital cost estimates are probably too high from a long-run marginal cost perspective (i.e., economic analysis). As mentioned previously, incremental cost calculations may be overestimated because joint-ownership of units was not considered. Also, incremental costs are overestimated because LTF capacity reductions among customers were based on historical capacity allocation splits and not on the basis of incremental cost. That is, to minimize costs, LTF capacity purchases would be made from utility systems with the lowest long-run marginal costs. Current costs are based on a proportional decrease in capacity among large customers.

Incremental capacity replacement costs for large customers under Alternatives 4 and 5 were based on capacity reductions of 647 and 582 MW, respectively. However, at the

TABLE 50 Total Net Present Value for Different Assumed Values for the Economic Cost of Western Capacity Purchases[a]

Commitment-Level Alternative/ Assumed Cost for Purchasing Capacity ($/kW-yr)	Hydropower Operational Scenario: High Flexibility		Medium Flexibility		Low Flexibility	
	Total NPV ($$10^6$)	Increase ($$10^6$)	Total NPV ($$10^6$)	Increase ($$10^6$)	Total NPV ($$10^6$)	Increase ($$10^6$)
No Action						
21	37,948.7	0.0	38,158.7	210.0	38,306.7	358.0
43	37,948.7	0.0	38,226.5	277.8	38,460.4	511.7
64	37,948.7	0.0	38,294.1	345.5	38,614.1	665.4
107	37,948.7	0.0	38,429.6	480.9	38,921.6	972.9
150	36,878.2	0.0	38,565.0	616.3	39,229.1	1,280.4
193	36,878.2	0.0	38,700.4	751.7	39,536.6	1,587.9
Alternative 2						
21	37,965.9	17.2	38,141.8	193.1	40,977.5	330.1
43	37,988.8	40.1	38,242.0	293.3	41,173.5	513.2
64	38,011.8	63.2	38,342.1	393.4	41,369.3	696.1
107	38,057.7	109.0	38,542.4	593.7	41,761.1	1,062.2
150	38,103.6	154.9	38,742.7	794.0	42,152.9	1,428.2
193	38,100.1	200.7	38,943.0	994.3	42,544.7	1,794.2
Alternative 5						
21	38,100.1	151.4	38,258.5	309.8	40,995.8	347.2
43	38,100.1	151.4	38,258.5	309.8	41,032.8	381.8
64	38,100.1	151.4	38,258.5	309.8	41,070.1	416.6
107	38,100.1	151.4	38,258.5	309.8	41,144.5	486.1
150	38,100.1	151.4	38,258.5	309.8	41,218.7	555.5
193	38,100.1	151.4	38,258.5	309.8	41,293.0	625.0
Alternative 4						
21	38,079.3	130.6	38,205.8	257.1	40,978.8	331.4
43	38,079.3	130.6	38,205.8	257.1	40,988.8	340.7
64	38,079.3	130.6	38,205.8	257.1	40,998.8	350.1
107	38,079.3	130.6	38,205.8	257.1	41,018.8	368.7
150	38,079.3	130.6	38,205.8	257.1	41,038.6	387.2
193	38,079.3	130.6	38,205.8	257.1	41,058.5	405.8

[a]All costs are in constant 1994 dollars.

90% exceedance level, losses in SLCA/IP hydropower plant capacity can exceed 950 MW under the low-flexibility scenario (Table 13). Therefore, marginal LTF capacity costs for these scenarios have a larger degree of uncertainty and are most likely higher than the medium- and high-flexibility scenarios. Instead of entering into an LTF capacity contract, a second option would be to build additional capacity. For example, Western could construct a new gas turbine or have it constructed by an independent power producer. Assuming a real discount rate of 5% and a lifetime of 35 years, gas turbines would cost approximately $32 to $43/kW-yr. Although gas turbines are expensive to operate, they would be used only when Western cannot purchase energy at a reasonable price on the spot market or when spot market agreements are abruptly "cut off" and a new spot market purchase agreement cannot be made in time to serve firm load. Because of its extensive transmission network, Western is connected to many utility systems and therefore can purchase on the spot market at a reasonable market price. That is, Western is not restricted to purchase from only one utility system that may set the spot market price at a level that is slightly less than the cost of operating a gas turbine.

As shown in Table 50, total costs are sensitive to the assumed price of LTF capacity purchases under the low-flexibility scenario where significant LTF capacity purchases are required. Total costs also change significantly as a function of capacity purchase cost under both the No Action Alternative and Alternative 2 with medium flexibility. At an LTF capacity purchase price of $43/kW-yr, the NPV estimates of total cost increases are less than $535 million.

Although many uncertainties are associated with any complex analysis that involves numerous utility systems with complex interactions, Table 50 shows that certain combinations of commitment-level alternative and operational scenario are more costly than others. For example, both Alternatives 4 and 5 under the high-flexibility scenario result in substantial total cost increases above the No Action Alternative with high flexibility. Although generation costs for Alternatives 4 and 5 are projected to decrease slightly, overall costs increase because of capital expenditures and increased fixed O&M costs for additional capacity expansion.

From an economic standpoint, the additional capacity that must be built to compensate for reductions in Western LTF capacity is somewhat inefficient because additional capacity is being built without lost capacity at SLCA/IP hydropower plants. That is, some of the SLCA/IP hydropower plant capacity is not accounted for in any of the utility systems' capacity expansion plans. Generation costs under both Alternatives 4 and 5 decrease slightly because Western can sell more energy during on-peak hours to the spot market instead of selling the energy to its customers under a firm contract. Slight decreases in generation costs are projected to occur because marginal prices drive the purchase and sale of SLCA/IP hydropower plant generation during on-peak hours. From an economic standpoint, this process is more efficient than energy sales under LTF contractual arrangements that are, in part, based on an allocation process that is not strictly driven by a cost minimization objective.

At the other end of the spectrum, under both the No Action Alternative and Alternative 2 with low flexibility, Western is selling LTF capacity that cannot be solely supported by SLCA/IP hydropower plants. Capacity must be purchased on an LTF basis. If capacity can be economically purchased at an inexpensive rate (i.e., $43/kWh), costs will be approximately equal to that of the other commitment-level alternatives under the low-flexibility scenario. That is, when LTF capacity purchase costs are approximately equal to capacity replacement costs of its firm customers, overall economic cost increases are similar.

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APPENDIX A:

GENERAL UTILITY DESCRIPTION OF THE 12 LARGE WESTERN CUSTOMERS

TABLE A.1 Arizona Power Pooling Association

Ownership/type	State
General location/state	Arizona
Headquarters	Benson, Arizona
Power pool/member organization	Arizona Power Pooling Association CREDA
Number and list of members	Arizona Electric Power Cooperative, Inc. City of Mesa Electrical District No. 2 San Carlos Irrigation Project
Population served	Not available
Historical load[a,b]	1991 system peak season: summer 1991 system peak (MW): 647.6 1991 energy sales (GWh): 3,667.8
Existing capacity mix[a]	Hydro (MW): 10 (1.9%) Coal (MW): 350 (66.0%) Gas (MW): 170 (32.1%) Total (MW): 530 (100%)
SLCA allocation	Capacity (MW): 45 (6.9% of 1991 system peak load) Energy (GWh): 113.1 (3.1% of 1991 energy sales)
Other interconnections	Not available
Unique characteristics	The third smallest Salt Lake City Area customer in terms of energy allocation among the 12 utilities. It is the fifth largest utility in terms of peak load. It has a purely thermal system and is predominantly coal based.
Other remarks	No jointly owned units
Transmission system	Not available
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Bulk generation, transmission, and distribution of electric power

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

[b] Sum of individual member system peak and energy sales.

TABLE A.2 Colorado-Ute Electric Association, Inc.

Ownership/type	Rural electric cooperative
General location/state	Colorado
Headquarters	Montrose, Colorado
Power pool/member organization	Inland Power Pool
Number and list of members	Serves 14 wholesale distribution cooperatives
Population served	Has 240,000 retail customers. It services an area of 50,000 mi^2, more than half of the area of the state of Colorado.
Historical load[a]	1990 system peak season: winter 1990 system peak (MW): 773.0 1990 energy sales (GWh): 6,745.7
Existing capacity mix	Coal (MW): 1,143.0 (98.9%) Hydro (MW): 12.5 (1.1%) Total (MW): 1,155.5 (100 %)
SLCA allocation	Capacity (MW): 33 (4.3% of 1990 system peak load) Energy (GWh): 158.7 (2.4% of 1990 energy sales)
Other purchases	Purchases from numerous utilities, including: Tri-State Generation and Transmission Public Service Company of Colorado Colorado Springs El Paso Electric Plains Generation and Transmission Deseret Generation and Transmission Also has long-term firm purchase contract with Western's Loveland Area Office.
Other sales[b]	Firm power sales contract with Public Service Company of Colorado
Other interconnections	Not available
Unique characteristics	Its service territories and resources are split among Tri-State, Public Service Company of Colorado, and PacifiCorp. It is predominantly coal based and is the fourth smallest Salt Lake City Area customer among the 12 utilities in terms of energy allocation. In terms of size, it is the second largest utility next to the Salt River Project. It is the second largest system in Colorado.
Other remarks	Has jointly owned coal-fired units: Craig 1 and 2, Hayden 2.
Transmission system	69, 115, 138, 230, 345 kV; 1,805 circuit miles
Year founded/organized	1941
Mission statement	Nonprofit cooperative. Financial returns are such that these are sufficient only to recover operating cost, debt service, and maintenance. It is a non-stock, nonprofit organization. Its mission is to provide quality electric service to its 14 retail distribution cooperatives. (See "Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934," Col-Ute report for fiscal year ended December 31, 1990, p. 1.)
General nature of business	Bulk generation and transmission; conducts purchase and resale activities; retail distribution done by its 14 retail distribution cooperatives; sells surplus power and energy to other regional power suppliers

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

[b] Source: *Public Service and Electric Demand and Supply Plan*, System Planning Division, Public Service Company of Colorado, Dec. 1990.

TABLE A.3 Colorado Springs Utilities

Ownership/type	Municipal
General location/state	Colorado
Headquarters	Colorado Springs, Colorado
Power pool/member organization	CREDA
Number and list of members	No member organization but serves customers in the Colorado Springs area
Population served	Colorado Springs: 286,000 Manitou Springs: 4,535 Security/Wisefield: 26,820 Green Mountain: 663 Total: 318,000
Historical load[a]	1991 system peak season: winter 1991 system peak (MW): 532.0 1991 energy sales (GWh): 3,007.7
Existing capacity mix[a]	Hydro (MW): 6.0 (1.0%) Coal (MW): 505.0 (84.8%) Gas (MW): 84.2 (14.1%) Total (MW): 595.2 (100%)
SLCA allocation	Capacity (MW): 70 (13.2% of 1991 system peak load) Energy (GWh): 165.8 (5.5% of 1991 energy sales)
Other purchases	Western's Loveland Area Office
Major interconnections	Western, Upper Colorado Public Service of Colorado
Unique characteristics	In terms of system load, it is the fourth largest utility among the 12 included in the study and is a medium-size SLCA customer relative to the 12 other utilities (fifth smallest allocation).
Other remarks	No jointly owned units
Transmission system	13, 35, 115, 230 kV
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Nonprofit, generation, transmission, and distribution

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

TABLE A.4 Deseret Generation and Transmission Co-operative

Ownership/type	Rural electric cooperative
General location/state	Utah
Headquarters	Sandy, Utah
Power pool/member organization	Inland Power Pool
Number and list of members	Serves six electric cooperatives: Bridger Valley Dixie-Escalante Garkane Power Flowell Electric Moon Lake Mt. Wheeler
Population served	Not available
Historical load[a,b]	1991 system peak season: summer 1991 system peak (MW): 244.7 1991 energy sales (GWh): 1,507.5
Existing capacity mix[a]	Coal (MW): 518.0 (100%)
SLCA allocation	Capacity (MW): 120.2 (49.1% of 1991 system peak load) Energy (GWh): 543.1 (36.0% of 1991 energy sales)
Other purchases [a]	Numerous utilities, including: Col-Ute Utah Associated Municipal Power System Utah Municipal Power Agency Utah Power and Light Pacific Power and Light Los Angeles Department of Water and Power
Major interconnections	Western, Upper Colorado Public Service of Colorado
Unique characteristics	It is the fourth smallest of the 12 SLCA utilities included in the study, but the fifth largest SLCA customer among the 12 utilities.
Other remarks	Capacity expansion not performed in the study, but long-term forecast developed for spot market simulation. It shares ownership of two coal plants: Bonanza, 409 MW (representing 96.25% share), and Hunter Unit 2, 97.9 MW (representing 25.11% share).
Transmission system	115,345 kV; 290 circuit miles
Year founded/organized	1977
Mission statement	It gives marked emphasis to environmental protection and substantiated it through massive investments in pollution and monitoring equipment. (See "Deseret Generation & Transmission Cooperative 1990 Annual Report," pp. 1-7.)
General nature of business	Bulk generation and transmission

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

[b] Sum of members system peak and energy sales.

TABLE A.6 Plains Electric Generation and Transmission Cooperative, Inc.

Ownership/type	Rural electric cooperative
General location/state	New Mexico
Headquarters	Albuquerque, New Mexico
Power pool/member organization	CREDA and Inland Power Pool
Number and list of members	Serves 13 wholesale electric cooperatives: Central New Mexico, Columbus, Continental Divide, Jemez Mountains, Kit Carson, Mora-San Miguel, Navopache, Northern Rio Arriba, Otero County, Sierra, Socorro, Southwestern, Springer
Population served	Not available
Historical load[a]	1991 system peak season: summer 1991 system peak (MW): 298.8 1991 energy sales (GWh): 2,144.5
Existing capacity mix[a]	Coal (MW): 250.0 (84.3%) Gas (MW): 46.5 (15.7%) Total (MW): 296.5 (100%)
SLCA allocation	Capacity (MW): 140 (46.9% of 1991 system peak load) Energy (GWh): 673.3 (31.4% of 1991 energy sales)
Other purchases[a]	Public Service Company of New Mexico
Major interconnections	No additional data
Unique characteristics	It is a medium-size utility in terms of system load, but it has the second largest SLCA allocation among the 12 utility customers. It is a purely coal-based system.
Other remarks	No jointly owned facilities
Transmission system	69, 115, 230 kV; 1,274 circuit miles
Year founded	Not available
Mission statement	To improve business through reliable, safe power supply and minimize cost of energy to its members. (See *Plains Electric Generation and Transmission Cooperative, Inc., 1990 Annual Report*, pp. 2-3.)
General nature of business	Generation and transmission; retail distribution to end users done by customer coops; involved in firm and interruptible wheeling services

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

TABLE A.5 Farmington/Aztec Electric Utilities

Ownership/type	Municipal utility system
General location/state	New Mexico
Headquarters	Farmington, New Mexico
Power pool/member organization	CREDA and Inland Power Pool (Farmington only)
Number and list of members	No members, but service covers three areas: Farmington Bloomfield Aztec
Population served[a]	Farmington 36,500 Bloomfield 6,000 Aztec 6,300 Total 48,800
Historical load[a,b]	1990 system peak season: summer 1990 system peak (MW): 88.7 1990 energy sales (GWh): 476.4
Existing capacity mix[a]	Hydro (MW): 30.0 (28.7%) Coal (MW): 42.2 (40.4%) Gas (MW): 32.2 (30.8%) Total (MW): 104.4 (100%)
SLCA allocation	Capacity (MW): 18 (20.3% of 1990 system peak load) Energy (GWh): 87.1 (18.3% of 1990 energy sales)
Other purchases[a]	Public Service Company of New Mexico
Unique characteristics	Aztec and Farmington modeled as one combined utility. It is the second smallest of the 12 SLCA utility customers included in the study next to Western. It is also the second smallest SLCA customer among the 12. It is a predominantly a gas-based system.
Other remarks	Has 8.8% ownership share of San Juan Unit 4 (42 MW out of 498 MW). The utility is one of the account groups (service groups) within the city of Farmington focusing mainly on electric service to the city, including generation, administration, engineering, and distribution of power and energy.
Transmission system	5, 13, 69, 115 kV; 145.2 circuit miles for 69 and 115 kV
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Generation, transmission, and distribution of electricity within the cities of Farmington and Aztec

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

[b] Sum of individual utility system peaks and energy sales.

TABLE A.7 Platte River Power Authority

Ownership/type	Federal (owned by cities of Estes Park, Fort Collins, Longmont, and Loveland)
General location/state	Colorado
Headquarters	Fort Collins, Colorado
Power pool/member organization	CREDA and Inland Power Pool
Municipalities served	Supplies power to the following municipal electric systems at wholesale (for subsequent retail to end users): Estes Park Fort Collins Longmont Loveland
Population served	Not available
Historical load[a]	1991 system peak season: summer 1991 system peak (MW): 282.8 1991 energy sales (GWh): 1,709.1
Existing capacity mix[a]	Coal (MW): 409 (100%) Total (MW): 409 (100%)
SLCA allocation	Capacity (MW): 126 (44.6% of 1991 system peak load) Energy (GWh): 641.8 (37.6% of 1991 energy sales)
Other purchases	Also has long-term firm contract with Western's Loveland Area Office.
Other sales[b]	Firm power sales to Public Service Company of Colorado
Major interconnections	No additional data
Unique characteristics	It is fourth largest SLCA customer among the 12 utilities. In terms of total system load, it is a medium-sized utility relative to the 12. It is a purely coal-based system.
Other remarks	Has joint ownership of Craig 1 and 2.
Transmission system	115, 230 kV; 187 circuit miles
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Bulk generation and transmission

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

[b] Sources: *Public Service and Electric Demand and Supply Plan*, System Planning Division, Public Service Company of Colorado, Dec. 1990. See also, *Financial Stability for Growth in the '90's*, Platte River Power Authority 1990 Annual Report.

TABLE A.8 Salt River Project Agricultural Improvement and Power District

Ownership/type	Federal, state, and district system (chartered by the state of Arizona to provide water and power)
General location/state	Arizona
Headquarters	Phoenix, Arizona
Power pool/member organization	CREDA and Inland Power Pool
Number and list of members	Supplies power to the following: Phoenix and other surrounding communities Indian reservations Chandler (parts only) Glendale Mesa Scottsdale Temple and others
Population served	18 towns: 1,200,000; covering 2,900 mi^2
Historical load[a]	1991 system peak season: summer 1991 system peak (MW): 3,373 1991 energy sales (GWh): 17,427.3
Existing capacity mix[a]	Hydro (PS) (MW): 238.2 (5.5%) Coal (MW): 2,069.1 (47.4%) Nuclear (MW): 666.4 (15.3%) Gas (MW): 1,392.3 (31.9%) Total (MW): 4,366.0 (100%)
SLCA allocation	Capacity (MW): 149 (4.4% of 1991 system peak load) Energy (GWh): 480.9 (2.8% of 1991 energy sales)
Other purchases[b]	Also has long-term firm contracts with Park-Davis and Hoover Dam made via Western's Phoenix Area Office.
Other sales[b]	Has long-term firm sales contract with: Mesa, Arizona Vernon, California San Carlos Irrigation District Cyprus Copper Mine Arizona Public Service Company
Unique characteristics	It is sixth largest SLCA customer among the 12 utilities. In terms of total load, it is the largest of the 12 utilities. It is a predominantly coal-based system and the only system with a pumped hydro facility. It is the nations's third largest public power utility.
Other remarks	Has joint ownership of Coronado (Apache) 1, the combined organization of which the power is a part of the oldest and most successful reclamation development in the United States.
Transmission system	69, 115, 230, 500 kV; 1,797 circuit miles (transmission) 5, 13, 25 kV; 3,147 circuit miles (distribution)
Year founded/organized	1903

TABLE A.8 (Cont.)

Mission statement[a]	To be the low-cost supplier among its competitors of high-value energy and water services.
General nature of business	Generation, transmission, and distribution, as well as buying and selling ventures

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

[b] Source: *Annual Report 1989-90,* Salt River Project.

TABLE A.9 Tri-State Generation and Transmission Association, Inc.

Ownership/type	Rural electric cooperative
General location/state	Colorado
Headquarters	Denver, Colorado
Power pool/member organization	CREDA and Inland Power Pool
Number and list of members	Supplies power to 24 wholesale distribution cooperatives throughout Colorado, Wyoming, and Nebraska. Its members are its owners.
Population served	Supplies power to 24 cooperatives serving 148,000 people in an area of 100,000 mi^2.
Historical load[a]	1991 system peak season: summer 1991 system peak (MW): 1,675 1991 energy sales (GWh): 6,669.2
Existing capacity mix[a]	Coal (MW): 602.8 (85.8%) Oil (MW): 100.0 (14.2%) Total (MW): 702.8 (100%)
SLCA allocation	Capacity (MW): 252 (15.0% of 1991 system peak load) Energy (GWh): 1,099.1 (16.5% of 1991 energy sales)
Other purchases[b]	Also has long-term firm contracts with Western's Loveland Area Office.
Other sales[c]	Firm power sales to Public Service Company of Colorado.
Major interconnections	Not available
Unique characteristics	The largest SLCA customer among the 12. In terms of total system load, however, it is the third largest among the 12. It is a predominantly coal-based system.
Other remarks	Has joint ownership of Laramie and Craig stations. Since the start of the Western study, it has acquired additional capacity and cooperative members as a result of the Col-Ute breakup.
Transmission system	115, 230, 345 kV; 2,000 circuit miles
Year founded/organized	1952 by rural electric cooperatives and public power district in Colorado, Nebraska, and Wyoming
Mission statement[a]	To provide member owners with a reliable, cost-based supply of electricity while maintaining a sound financial position through effective utilization of human, capital, and physical resources in accordance with cooperative principles.
General nature of business	Generation and transmission; retail distribution to end users is left to the cooperatives

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

[b] Source: *The New Tri-State — A New Horizon,* Tri-State Generation and Transmission Association, Inc., Annual Report, 1991.

[c] Source: *Public Service and Electric Demand and Supply Plan,* System Planning Division, Public Service Company of Colorado, Dec. 1990.

TABLE A.10 Utah Associated Municipal Power Systems

Ownership/type	State; a separate political subdivision of the state of Utah composed of Utah municipalities, one special service district, Heber Light and Power Company
General location/state	Utah
Headquarters	Sandy, Utah
Number and list of members	Has 29 members consisting of utilities owned by member cities and municipalities. It has 30 municipalities, 1 interlocal joint action community, 1 special service district and 4 contract purchasers.[b]
Population served	More than 240,000
Historical load[a]	1991 system peak season: not available 1991 system peak (MW): 312 1991 energy sales (GWh): 755.0
Existing capacity mix[a,b]	Hydro (MW): 25.5 (10.6%) Coal (MW): 146.9 (61.2%) Oil/Gas (MW): 67.8 (28.3%) Total (MW): 240.2 (100%)
SLCA allocation	Capacity (MW): 174 (55.7% of 1991 system peak load) Energy (GWh): 664.3 (88.0% of 1991 energy sales)
Other purchases[a]	Also long-term firm contracts with Idaho Power Company
Major interconnections	Not available
Unique characteristics	It is the fourth largest SLCA customer among the 12 utilities. It is predominantly a coal-based system. It has the largest number (28 units in all) of hydro units, albeit low-capacity ones.
Other remarks	Has joint ownership of Intermountain Power Plant (14.04% of 1,600 MW).
Transmission system	Not available
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Bulk generation and transmission

[a] Source: Hunter Project Refunding Reserve Bonds, 1992 Series.

[b] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

TABLE A.11 Utah Municipal Power Agency

Ownership/type	State (a separate legal entity and political subdivision of the state of Utah)
General location/state	Utah
Headquarters	Spanish Fork, Utah
Power pool/member organization	CREDA, Inland Power Pool
Number and list of members	Has six governmental entities as members: Manti City Corporation Salem City Corporation Provo City Corporation Nephi City Corporation Spanish Fork City Corporation Town of Levan
Population served	102,000
Historical load	1991 system peak season: summer 1991 system peak (MW): 124.5 1991 energy sales (GWh): 660.6
Existing capacity mix	Hydro (MW): 3.9 (4.4%) Coal (MW): 56.0 (63.7%) Gas (MW): 18.0 (20.5%) Other (MW): 10.0 (11.4%) Total (MW): 87.9 (100%)
SLCA allocation	Capacity (MW): 76 (60.3% of 1991 system peak load) Energy (GWh): 388.2 (50.3% of 1991 energy sales)
Other purchases	Also has long-term firm purchase contract with Utah Power and Light.
Major interconnections	No additional data
Unique characteristics	Small utility system among the 12 SLCA customers. It is predominantly a coal-based system.
Other remarks	Has joint ownership of Hunter 1 and Bonanza Coal power stations.
Transmission system	138- and 345-kV system; 377 circuit miles
Year founded/organized	September 17, 1980, pursuant to the Utah Interlocal Cooperation Act
Mission statement	Planning, financing, development, acquisition, construction, improvement, betterment, operation or maintenance of projects for the generation, transmission, and distribution of electric energy for the benefit of its members. (See "Utah Municipal Power Agency 1991 Annual Report.")
General nature of business	Bulk generation, transmission, and distribution

Source: *Utah Municipal Power Agency Annual Report 1991.*

TABLE A.12 Wyoming Municipal Power Agency

Ownership/type	State
General location/state	Utah
Headquarters	Lusk City, Utah
Power pool/member organization	CREDA, Inland Power Pool
Number and list of members	Has eight member cities and an irrigation district: Cody Fort Laramie Guernsey Lingle Lusk Powell Pine Bluffs Wheatland
Population served	Not available
Historical load[a]	1991 system peak season: winter 1991 system peak (MW): 30.8 1991 energy sales (GWh): 169.5
Existing capacity mix[a]	Coal (MW): 22.6 (100%)
SLCA allocation	Capacity (MW): 7.0 (22.7% of 1991 system peak load) Energy (GWh): 25.2 (14.9% of 1991 energy sales)
Other purchases	Also has long-term firm purchase contract with Western's Loveland Area Office.
Other sales[b]	Has a four-year peaking sales contract with the neighboring town of Gillette.
Major interconnections	No additional data
Unique characteristics	The smallest of the 12 SLCA utility customers covered in the study. It is a 100% coal-based system.
Other remarks	Has joint ownership of Laramie River stations 1, 2, and 3.
Transmission system	69 kV; 7.67 circuit miles
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Bulk generation, transmission to member cities for sale to municipalities. Independent utilities within the city distribute power to end users.

[a] Source: *Electrical World Directory of Electric Utilities: 1993* (1992).

[b] Source: Personal communication with Burt Pond (primary ANL contact for Wyoming Municipal Power Agency).

APPENDIX B:

EXISTING GENERATION SOURCES AND FACILITIES OF THE 12 LARGE WESTERN CUSTOMERS

TABLE B.1 Existing Generation Sources of the 12 Large Western Customers

Unit	Capacity (MW)	Primary Fuel	Plant-Level Fuel Cost (¢/10^6Btu)
Arizona Power Pooling Association			
Coolidge Plant	10	Hydro	0
Subtotal	10	(1.9%)	
Apache ST2	175	Sub. coal	127.8[a]
Apache ST3	175	Sub. coal	127.8[a]
Subtotal	350	(66.0%)	
Apache CT2	20	Gas	165.0[a]
Apache CT3	69	Gas	165.0[a]
Apache ST1, CT1	81	Gas	165.0[a]
Subtotal	170	(32.1%)	
Total	530	(100%)	
Colorado-Ute Electric Association, Inc.			
Ames	4	Hydro	0.0
Tacoma 1, 2	2 × 2.25	Hydro	0.0
Tacoma 3	3.5	Hydro	0.0
Ouray	0.5		
Subtotal	12.5	(1.1%)	
Hayden 1	190	Bit. coal	92.0[a]
Hayden 2[b]	137.7	Bit. coal	92.0[a]
Craig 1[b], 2[b]	2 × 129.46	Bit. coal	72.1[a]
Craig 3	446.4	Bit. coal	72.1[a]
NUCLA 1-4	110	Bit. coal	125.5[c]
Subtotal	1,143.02	(98.9%)	
Total	1,155.52	(100%)	

TABLE B.1 (Cont.)

Unit	Capacity (MW)	Primary Fuel	Plant-Level Fuel Cost (¢/10^6Btu)
Colorado Springs Utilities			
Manitou 1, 2	5	Hydro	0
Ruxton	1	Hydro	0
Subtotal	6	(1.0%)	
M. Drake 5	55	Coal	164.3[a]
M. Drake 6	85	Coal	164.3[a]
M. Drake 7	142	Coal	164.3[a]
Ray D. Nixon 1	223	Coal	141.7[a]
Subtotal	505	(84.8%)	
G. Birdsall 1	18.5	Gas	522.0[c]
G. Birdsall 2	18.5	Gas	522.0[c]
G. Birdsall 3	24.2	Gas	522.0[c]
M. Drake 1	5.5	Gas	338.7[a]
M. Drake 3	5.5	Gas	338.7[a]
M. Drake 4	12.0	Gas	338.7[a]
Subtotal	84.2	(14.1%)	
Total	595.2	(100%)	
Farmington / Aztec Electric Utilities			
Navajo 1, 2	2 × 15	Hydro	0
Subtotal	30.0	(28.7%)	
San Juan 4[b]	42.2	Coal	173.4[a]
Subtotal	42.2	(40.4%)	
Animas 1	3.7	Gas	229.06[d]
Animas 2	3.5	Gas	229.06[d]
Animas 3	8.5	Gas	229.06[d]
Animas 4	16.5	Gas	229.06[d]
Subtotal	32.2	(30.8%)	
Total	104.4	(100%)	

TABLE B.1 (Cont.)

Unit	Capacity (MW)	Primary Fuel	Plant-Level Fuel Cost (¢/10^6Btu)
Deseret Generation and Transmission Co-operative			
Bonanza 1	420	Bit. coal	201.4[a]
Hunter 2[b]	98	Bit. coal	94.4[a]
Total	518		
Plains Electric Generation and Transmission Cooperative, Inc.			
Escalante	250	Sub. coal	137.6[a]
Subtotal	250	(84.3%)	
Algodones 1, 2	15 × 2	Gas	NA
Algodones	16.5	Gas	NA
Subtotal	46.5	(15.7%)	
Total	296.5		
Platte River Power Authority			
Rawhide	255	Coal	86.4
Craig 1[b], 2	2 × 77	Coal	72.1[a]
Total	409	(100%)	

TABLE B.1 (Cont.)

Unit	Capacity (MW)	Primary Fuel	Plant-Level Fuel Cost (¢/10^6Btu)
Salt River Project			
South Consolidated	1.4	Hydro	0
Roosevelt 1	36	Hydro	0
Horse Mesa 1-3	3 × 9.9	Hydro	0
Horse Mesa 4	99.88	Pump stor.	0
Mormon Flat 1	9.2	Hydro	0
Mormon Flat 2	48.65	Pump stor.	0
St. Mountain	10.4	Hydro	0
Crosscut	3	Hydro	0
Subtotal	238.23	(5.5%)	
Four Corners 4,[b] 5[b]	2 × 81.81	Coal	106.7[a]
Coronado 1, 2	821.88	Bit. coal	200.9[a]
Craig 1,[b] 2[b]	259.4	Coal	72.1[a]
Hayden 2[b]	137.7	Coal	92.0[a]
Mohave 1, 2	2 × 81.81	Coal	118.9[a]
Navajo 1,[b] 2,[b] 3[b]	3 × 174.29	Bit. coal	104.8[a]
		1	
Subtotal	2,069.09	(47.4%)	
Palo Verde 1-3[b]	666.37	Nuclear	NA[e]
Subtotal	666.37	(15.3%)	
	7		
Agua Fria 1, 2	2 × 113.64	Gas steam NG	282.4[a]
Agua Fria 3	163.2	Gas steam NG	282.4[a]
Agua Fria 4	80.55	Gas turbine NG	282.4[a]
Agua Fria 5, 6	2 × 71.2	Gas turbine NG	282.4[a]
Kyrene 1	34.5	Gas steam NG	231.7[c]
Kyrene 2	73.5	Gas steam NG	231.7[c]
Kyrene 3, 4	2 × 60.3	Gas turbine NG	231.7[c]
Kyrene 5, 6	2 × 53.13	Gas turbine NG	231.7[c]
San Tan 1-4	4 × 103.5	Comb. cycle NG	279.3[a]
Crosscut 1-4	4 × 7.5	Gas steam NG	NA
Subtotal	1,392.29	(31.9%)	
Total	4,365.98	(100%)	

TABLE B.1 (Cont.)

Unit	Capacity (MW)	Primary Fuel	Plant-Level Fuel Cost (¢/10^6Btu)
Tri-State Generation and Transmission Association, Inc.			
Laramie River 1,[b] 2,[b] 3[b]	3 × 132.6	Sub. coal	52.6[a]
Craig 1,[b] 2[b]	2 × 102.5	Bit. coal	72.1[a]
Subtotal	602.8	(85.8%)	
Burlington 1, 2	2 × 50	FO2	455.1[a]
Subtotal	100.0	(14.2%)	
Total	702.8	(100%)	
Utah Associated Municipal Power Systems[f]			
Combined Hydro	25.5	Hydro	0.0
Subtotal	25.5	(10.6%)	
San Juan 4[b]	40.0	Coal	173.4[a]
IPP 1,[b] 2[b]	2 × 25.0	Coal	149.3[a]
Hunter 2[b]	56.9	Coal	94.3[a]
Subtotal	146.9	(61.2%)	
Logan 2, 3	2 × 0.8	Oil	NA
Logan 4	1.3	Oil	NA
Logan 5A, 5B	2 × 1.0	Oil	NA
Logan 6	2.3	Oil	NA
St. George 1, 2	2 × 7.0	Oil	NA
Ephraim 1	2 × 0.3	Oil	NA
Ephraim 2	0.3	Oil	NA
Heber 6	1.6	Oil	NA
Subtotal	23.7	(9.9%)	

TABLE B.1 (Cont.)

Unit	Capacity (MW)	Primary Fuel	Plant-Level Fuel Cost (¢/10^6Btu)
Utah Associated Municipal Power Systems (Cont.)			
Bountiful 2, 3	2 × 1.3	Gas	NA
Bountiful 4, 5	2 × 1.0	Gas	NA
Bountiful 6	2.5	Gas	NA
Bountiful 8	8.0	Gas	NA
Murray 1, 2	2 × 1.0	Gas	NA
Murray 3	2.0	Gas	NA
Murray 4	2.6	Gas	NA
Spring City 1, 2	2 × 7.0	Gas	NA
Heber 1-5	5 × 0.6	Gas	NA
Payson 1, 2	2 × 2.7	Gas	NA
Subtotal	44.1	(18.4%)	
Total	240.2	(100.0%)	
Utah Municipal Power Agency			
Pigeon Creek	0.21	Hydro	0
Cobble Rock	0.11	Hydro	0
Manti Upper/Lower	2.7	Hydro	0
Nephi Upper	0.2	Hydro	0
Nephi Lower	0.7	Hydro	0
Subtotal	3.9	(4.4%)	
Bonnette Geothermal	10	Geo. steam	0.0
Subtotal	10	(11.4%)	
Hunter 1 coal[a]	25.00	Bit. coal	94.4[a]
Bonanza coal[a]	31.00	Bit. coal	201.4[a]
Subtotal	56.00	(63.7%)	
Provo 5 Diesel	2.5	Gas	NA
Provo 6 Diesel	2.5	Gas	NA
Provo 7 Diesel	2.5	Gas	NA
Provo 8 Diesel	2.5	Gas	NA
Provo Steam	8.0	Gas	NA
Subtotal	18.0	(20.5%)	
Total	87.9	(100%)	

TABLE B.1 (Cont.)

Unit	Capacity (MW)	Primary Fuel	Plant-Level Fuel Cost (¢/10^6Btu)
Wyoming Municipal Power Agency			
Laramie River 2[b]	11.3	Sub. coal	52.6[a]
Laramie River 3[b]	11.3	Sub. coal	52.6[a]
Total	22.6	(100%)	

[a] Average price in 1992; data from EIA FERC-423.

[b] Utility's ownership share.

[c] Average price in 1990; data from EIA FERC-423.

[d] Average price over all years in constant 1990 dollars; data from EIA FERC-423.

[e] Not available.

[f] Source: Hunter Project Refunding Reserve Bonds, 1992 Series.

APPENDIX C:

GENERAL UTILITY DESCRIPTION OF INVESTOR-OWNED UTILITIES

TABLE C.1 Arizona Public Service Company

Ownership/type	Investor-owned
General location/state	Arizona
Headquarters	Phoenix, Arizona
Power pool/member organization	Inland Power Pool
Number and list of members	Serves 11 of Arizona's 15 counties
Population served	Serves 1,695,000 or about 45% of the state's population
Historical load	1991 system peak season: summer 1991 system peak (MW): 3,532.0 1991 energy sales (GWh): 19,986.5
Existing capacity mix	Coal (MW): 2,037 (45.4%) Nuclear (MW): 1,109 (24.7%) Gas (MW): 1,330.8 (29.7%) Hydro (MW): 5.6 (0.1%) Total (MW): 4,482.4 (100 %)
SLCA allocation	Not a Western customer
Other purchases[a]	Has purchase contract with: PacifiCorp Salt River Project
Other sales	Not available
Other interconnections	Has about 29 major interconnection or interchange points with numerous utilities; tie voltages range from 69 to 500 kV.
Unique characteristics	It is the third largest of the five investor-owned utilities included in the study. It is a predominantly coal-based system.
Other remarks	Has numerous units jointly owned with other utilities.
Transmission system	OH: 13, 69, 115, 230, 345, 500 kV; 4,940 circuit miles UG: 13, 69, 230 kV; 18.7 circuit miles Distribution: 13 kV
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Generation, transmission, and distribution

[a] Source: Arizona Public Service Company 1990 Long Range Forecast of Loads and Resources, 1991.

TABLE C.2 Nevada Power Company

Ownership/type	Investor-owned
General location/state	Nevada
Headquarters	Las Vegas, Nevada
Number and list of members	Service territory includes most of Clark County in southern Nevada and portions of Nye County that includes the Nevada Test site. Towns served include Las Vegas, North Las Vegas, Laughlin, and Henderson, Nevada.
Population served	738,000
Historical load	1991 system peak season: summer 1991 system peak (MW): 2,373 1991 energy sales (GWh): 9,552.0
Existing capacity mix	Coal (MW): 1,082 (62.3%) Gas (MW): 654 (37.7%) Total (MW): 1,736 (100%)
SLCA allocation	Not a Western customer
Other purchases[a]	Has purchase contract with: PacifiCorp Tucson Electric Power Company Hoover Dam
Other sales	Not available
Other interconnections	Has about four major interconnection or interchange points with Western, LADWP, SCE, and SRP. All interconnections are 500 kV, except for Western.
Unique characteristics	It is the fourth largest of the five investor-owned utilities included in the study. It is predominantly a coal-based system.
Other remarks	Has numerous units jointly owned with other utilities.
Transmission system	OH: 69, 115, 230, 345, 500 kV; 1,449 circuit miles Distribution (UG): 13, 25 kV; 2,611 circuit miles Distribution (OH): 5, 13, 25, 35 kV; 3,027 circuit miles
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Generation, transmission, and distribution

[a] Source: *1991 Resource Plan and Action Plan, Vol. II,* Nevada Power Company.

TABLE C.3 PacifiCorp East Division (Utah/Wyoming Division)

Ownership/type	Investor-owned
General location/state	Utah
Headquarters	Salt Lake City, Utah
Power pool/member organization	One of two divisions of PacifiCorp Electric Operations Group (PEOG); the other division is the Pacific Power Division, based in Portland, Oregon. POEG was formed via the merger of the Utah Power and Light Company and the Pacific Power and Light Company.
Number and list of members	PEOG serves customers in seven states, including Utah, California, Montana, Oregon, Washington, Wyoming, and Idaho
Population served	1,160,000
Historical load	1991 system peak season: winter 1991 system peak (MW): 7,339.0 1991 energy sales (GWh): 40,783.8
Existing capacity mix	Hydro (MW): 169.2 (2.8%) Coal (MW): 5,554.1 (93.4%) Gas (MW): 198.6 (3.3%) Geothermal (MW): 23.5 (0.4%) Total (MW): 5,945.4 (100%) Hydro and gas capacities are net dependable capacities.
SLCA allocation	Not a Western customer
Other interconnections	Has numerous major interconnection or interchange points with at least 12 other utilities.
Unique characteristics	It is the largest of the five investor-owned utilities included in the study. It is a predominantly coal-based system.
Other remarks	Has numerous units jointly owned with other utilities.
Transmission system	OH: 69, 115, 230, 345, 500 kV; (UG): 69 kV; Distribution (OH): 5, 13, 25, 35 kV
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Generation, transmission, and distribution

TABLE C.4 Public Service Company of Colorado

Ownership/type	Investor-owned
General location/state	Colorado
Headquarters	Denver, Colorado
Power pool/member organization	Inland Power Pool
Number and list of members	Not available
Population served	Service territory includes about 54 towns and cities in the Colorado area; total population served is 850,000.
Historical load	1991 system peak (MW): 3,627.2 1991 energy sales (GWh): 19,831.4
Existing capacity mix	Hydro (MW): 340.2 (11.4%) Coal (MW): 2,374.3 (79.2%) Gas/Oil (MW): 282.0 (9.4%) Total (MW): 2,996.5 (100 %)
SLCA allocation	Not a Western customer
Other purchases[a]	Has power purchase contracts with Tri-State G&T, Colorado-Ute, Platte River Power Authority, and Basin Electric Power Cooperative.
Other interconnections	Has major interconnections with Western in 69-, 115-, and 230-kV tie voltages.[b]
Unique characteristics	It is the second largest of the five investor-owned utilities included in the study. It is a predominantly coal-based system. Since the start of the Western study, it has acquired additional capacity as result of the Colorado-Ute breakup. To remain as consistent as possible with the Glen Canyon Power resource study, the new additions were not included.
Other remarks	Has numerous units jointly owned with other utilities.
Transmission system	OH: 69, 115, 230, 345, 500 kV; 3,000 circuit miles; distribution (OH and UG): 5, 13, 25, kV; 18,000 miles.
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Electricity generation, transmission, and distribution; also purchase and sale (purchase for resale)

[a] Source: *Public and Electric Demand and Supply Plan*, System Planning Division, Public Service Company of Colorado, Dec. 1990.

[b] Source: *Electrical World Directory of Electric Utilities: 1993,* 101st Ed., McGraw-Hill, Inc., New York, N.Y., 1992.

TABLE C.5 Tucson Electric Power Company

Ownership/type	Investor-owned
General location/state	Arizona
Headquarters	Tucson, Arizona
Power pool/member organization	Inland Power Pool
Number and list of members	Not available
Population served	Service territory encompasses 1,155 mi^2 in Pima and Cochise in southern Arizona. Total population served is 700,000.
Historical load	1991 system peak season: winter 1991 system peak (MW): 1,320.0 1991 energy sales (GWh): 7,126.6
Existing capacity mix	Coal (MW): 1,204.3 (67.3%) Gas/Oil (MW): 585.7 (32.7%) Total (MW): 1,790.0 (100%)
SLCA allocation	Not a Western customer
Other purchases[a]	Has purchase contracts with Century Power Corporation to lease the 360-MW Springville coal-fired power plant.
Other sales	Not available
Other interconnections	Has numerous major interconnection or interchange points with at least 19 other utilities.
Unique characteristics	It is the smallest of the five investor-owned utilities included in the study. It is a predominantly coal-based system.
Other remarks	Has numerous units jointly owned with other utilities.
Transmission system	OH: 69, 115, 230, 345, 500 kV; 2,700 circuit miles; distribution (OH and UG): 5, 13, 25, 35 kV
Year founded/organized	Not available
Mission statement	Not available
General nature of business	Generation, transmission, and distribution; purchase and sale (purchase for resale)

[a] Source: *1991 Annual Report to Shareholders* and *1991 Form 10-K Report*, Tucson Electric Power Company.

APPENDIX D:

CAPACITY EXPANSION CANDIDATES

TABLE D.1 Capacity Expansion Candidates

Technology[a]	Fuel	Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Cost[b] ($/kW)	Fixed O&M[b] ($/kW-yr)	Variable O&M[b] (mill/kWh)	Forced Outage (%)	Annual Maint. (days/yr)
Gas turbine (8.8 MW, NG)[b]	NG	8.8	12,200	749	2.5	19.6	3.5	15
Gas turbine (20 MW, NG)	NG	20	10,860	599	1.6	14.3	3.5	15
Gas turbine (31 MW, NG)	NG	31	10,800	535	1.3	12.1	3.5	15
Gas turbine (40 MW, NG)	NG	40	12,650	503	1.1	11.1	3.5	15
Gas turbine (80 MW, NG)	NG	80	11,630	428	0.7	8.5	3.5	15
Gas turbine (140 MW, NG)	NG	140	12,520	412	0.7	8.1	3.5	15
Gas turbine (290 MW, NG)	NG	290	12,520	412	0.7	7.7	3.5	15
Combined turbine (80 MW, FO2)	Oil	80	11,800	546	0.9	8.6	3.5	15
Combined turbine (140 MW, FO2)	Oil	140	11,110	525	0.7	8.3	3.5	15
Combined turbine (280 MW, FO2)	Oil	280	11,100	482	0.7	8.0	3.5	15
Combined cycle (15.9 MW, NG)	NG	15.9	9,070	973	10.1	2.5	5.5	15
Combined cycle (50 MW, NG)	NG	50	8,590	1,167	6.1	2.5	5.5	15
Combined cycle (100 MW, NG)	NG	100	8,510	1,124	4.5	2.5	5.5	15
Combined cycle (200 MW, NG)	NG	200	8,380	814	2.6	2.5	5.5	15
Combined cycle (400 MW, NG)	NG	400	8,180	589	1.5	2.5	5.5	15
Combined cycle (420 MW, FO2)	Oil	420	7,780	567	2.9	2.2	5.5	15
AFBC (BB, 200 MW, bit.)	Coal	200	9,960	1,798	38.1	8.3	10.2	34
AFBC (CB, 200 MW, bit.)	Coal	200	10,060	1,670	36.9	8.8	10.2	34
AFBC (BB, 400 MW, bit.)	Coal	400	9,880	1,724	30.2	3.7	17.4	56
AFBC (BB, 200 MW, sub.)	Coal	200	10,220	1,745	37.3	4.8	10.2	34
AFBC (CB, 200 MW, sub.)	Coal	200	10,380	1,670	37.0	4.7	10.2	34
AFBC (BB, 200 MW, lig.)	Coal	200	10,330	1,766	37.7	6.4	10.2	34
AFBC (CB, 200 MW, lig.)	Coal	200	10,620	1,734	37.9	6.3	10.2	34
PFBC (CC, 340 MW, bit.)	Coal	340	8,980	1,574	44.1	7.2	18.9	34
PFBC (CC, 400 MW, bit.)	Coal	400	10,370	1,724	33.3	7.6	16.8	56
PFBC (CC, 640 MW, bit.)	Coal	640	8,510	1,552	44.4	4.6	18.9	34
PFBC (BB_TURBO, 250 MW, bit.)	Coal	250	9,700	1,638	32.8	6.9	15.7	34
PFBC (CB_TURBO, 250 MW, bit.)	Coal	250	10,280	1,520	33.7	7.2	15.3	34
STIG (5.6 MW, NG)	NG	5.6	10,490	1,809	19.4	3.0	3.9	15
STIG (50 MW, NG)	NG	50	9,200	942	5.5	3.0	3.9	15

TABLE D.1 (Cont.)

Technology[a]	Fuel	Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Cost[b] ($/kW)	Fixed O&M[b] ($/kW-yr)	Variable O&M[b] (mill/kWh)	Forced Outage (%)	Annual Maint. (days/yr)
STIG (100 MW, NG)	NG	100	9,170	781	3.6	3.0	3.9	15
STIG (200 MW, NG)	NG	200	9,140	717	2.4	3.0	3.9	15
STIG (350 MW, NG)	NG	350	9,110	664	1.7	3.0	3.9	15
Diesel (F-M, 1.6 MW, NG)	NG	1.6	9,140	2,430	16.9	4.5	3.4	14
Diesel (F-M, 2.4 MW, NG)	NG	2.4	9,140	2,034	16.9	4.5	3.4	14
Diesel (F-M, 3.2 MW, NG)	NG	3.2	9,140	1,746	16.9	4.5	3.4	14
Diesel (CAT, 3.6 MW, NG)	NG	3.6	8,200	1,595	17.8	22.8	3	14
Diesel (WAR, 4.0 MW, NG)	NG	4	8,270	1,531	17.8	22.7	3	14
Diesel (3 MW, FO2)	Oil	3	10,200	1,295	14.0	23.6	3	14
Diesel (12 MW, RESID)	Oil	12	9,000	996	10.6	8.8	3	14
Steam-elec. (100 MW, NG)	NG	100	11,000	846	14.3	6.1	8.5	38
Steam-elec. (200 MW, NG)	NG	200	10,700	749	12.8	4.1	8.5	38
Steam-elec. (400 MW, NG)	NG	400	10,500	653	11.5	2.7	8.5	38
Steam-elec. (800 MW, NG)	NG	800	10,200	578	10.2	1.8	8.5	38
Fuel cell (PAFC, 10 MW, NG)	NG	10	8,300	1,627	9.0	5.6	4.1	17
Fuel cell (PAFC, 16 MW, NG)	NG	16	8,300	1,392	9.0	5.6	4.1	17
Fuel cell (PAFC, 25 MW, NG)	NG	25	8,300	1,306	9.0	5.6	4	17
Fuel cell (PAFC, 100 MW, NG)	NG	100	8,300	1,188	9.0	5.6	4	17
Fuel cell (MCFC, 2 MW, NG)	NG	2	6,450	1,338	6.2	10.0	7.4	7
IGCC (BGL, 500 MW, bit.)	Coal	500	8,920	1,360	32.1	5.1	14.4	14
IGCC (BGL, 180 MW, bit.)	Coal	180	8,990	1,980	75.5	-0.1	14.4	14
IGCC (Dow, 800 MW, bit.)	Coal	800	8,690	1,327	35.9	0.5	10.6	17
IGCC (Dow, 400 MW, sub.)	Coal	400	8,670	1,210	39.6	0.8	10.6	16
IGCC (Dow, 400 MW, lig.)	Coal	400	9,630	1,317	42.7	1.0	10.6	16
IGCC (Shell, 390 MW, bit.)	Coal	390	9,010	1,831	24.5	3.9	13.9	16
IGCC (Shell, 500 MW, lig.)	Coal	500	10,430	1,788	39.0	5.7	14	16
IGCC (Texaco, 100 MW, bit.)	Coal	100	9,400	2,666	98.8	10.0	15.5	21
IGCC (Texaco, 360 MW, bit.)	Coal	360	9,000	1,756	47.1	4.8	15.5	21
PC-fired (wet, 200 MW, bit.)	Coal	200	9,450	1,606	35.6	6.9	19.5	42
PC-fired (wet, 300 MW, bit.)	Coal	300	9,450	1,542	32.5	6.5	19.5	42

TABLE D.1 (Cont.)

Technology[a]	Fuel	Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Cost[b] ($/kW)	Fixed O&M[b] ($/kW-yr)	Variable O&M[b] (mill/kWh)	Forced Outage (%)	Annual Maint. (days/yr)
PC-fired (wet, 500 MW, bit.)	Coal	500	9,450	1,445	28.5	6.4	19.5	42
PC-fired (wet, 1000 MW, bit.)	Coal	1,000	9,450	1,338	23.9	6.0	19.5	42
PC-fired (wet, 2000 MW, bit.)	Coal	2,000	9,450	1,210	20.4	5.6	19.5	42
PC-fired (wet, 200 MW, sub)	Coal	200	10,080	1,980	41.3	5.8	19.5	42
PC-fired (wet, 1000 MW, sub)	Coal	1,000	10,030	1,381	23.1	4.1	19.5	42
PC-fired (wet, 200 MW, lig.)	Coal	200	10,270	1,884	42.9	6.9	19.5	42
PC-fired (wet, 1000 MW, lig.)	Coal	1,000	10,110	1,413	24.5	4.8	19.5	42
PC-fired (SCRT, 200 MW, bit.)	Coal	200	9,840	1,809	42.7	7.6	19.5	42
PC-fired (SCRT, 400 MW, bit.)	Coal	400	9,720	1,402	40.0	6.9	14	35
PC-fired (SCRT, 500 MW, bit.)	Coal	500	9,650	1,295	24.1	5.9	19.5	42
PC-fired (spray, 200 MW, sub.)	Coal	200	10,070	1,488	30.8	4.4	15.2	35
PC-fired (spray, 300 MW, sub.)	Coal	300	10,070	1,467	28.9	4.2	15.2	35
PC-fired (spray, 500 MW, sub.)	Coal	500	10,070	1,435	25.7	3.9	15.2	35
PC-fired (spray, 750 MW, sub.)	Coal	750	10,070	1,381	23.2	3.5	15.2	35
PC-fired (spray, 300 MW, lig.)	Coal	300	10,230	1,488	29.5	5.5	15.2	42
PC-fired (spray, 300 MW, bit.)	Coal	300	9,570	1,349	27.9	3.9	15.2	24
PC-fired (advanced, 300 MW, bit.)	Coal	300	8,820	1,606	32.9	6.4	14.6	42
PC-fired (advanced, 200 MW, sub.)	Coal	200	8,820	1,552	30.7	4.3	15.2	35
PC-fired (advanced, 300 MW, sub.)	Coal	300	9,150	1,542	28.6	4.1	15.2	35
Conventional hydro (5 MW)	Water	5	0	2,987	30.1	4.4	2.4	8
Conventional hydro (10 MW)	Water	10	0	2,698	14.0	3.4	2.4	8
Conventional hydro (100 MW)	Water	100	0	1,927	1.1	1.6	2.4	8
Pumped hydro (500 MW)	Water	500	0	1,006	18.5	5.2	5.0	19
Pumped hydro (1,000 MW)	Water	1,000	0	926	4.5	4.5	5.0	19
Pumped hydro (2,000 MW)	Water	2,000	0	856	1.1	3.9	5.0	19
Steam-elec. (8 MW)	Wood	8	17,500	4,089	134.9	20.7	8.0	24
Steam-elec. (12 MW)	Wood	12	19,080	3,115	105.2	-10.7	8	24
Steam-elec. (24 MW)	Wood	24	16,250	2,377	68.5	-3.5	8	24
Steam-elec. (50 MW)	Wood	50	12,000	1,659	23.0	1.6	8.0	24
Geothermal, binary (54 MW)	Water	54	0	2,034	67.0	5.5	6.0	29
Solar-thermal (80 MW)	NG	80	3,300	3,212	51.2	1.0	4.0	14

TABLE D.1 (Cont.)

Technology[a]	Fuel	Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Cost[b] ($/kW)	Fixed O&M[b] ($/kW-yr)	Variable O&M[b] (mill/kWh)	Forced Outage (%)	Annual Maint. (days/yr)
Solar-photovoltaic (99 MW)	None	99	0	8,029	7.4	3.5	3.0	14
Wind turbine (300 × 0.25 MW)	None	75	0	1,499	11.8	16.1	5.0	0
CAES, Salt Dome (25 MW)	NG	25	4,040	674	1.4	1.1	8.5	8
CAES, Salt Dome (110 MW)	NG	110	4,040	466	1.4	1.1	8.5	8
Battery, lead (20 MW, 3 hours)	None	20	0	1,081	0.6	10.0	2.5	7
MSW, mass burn (40 MW)	MSW[b]	40	16,450	5,031	137.0	21.0	10	21
MSW, RDF (24 MW)	MSW	24	15,000	4,924	254.8	28.6	10	21

[a] AFBC = atmospheric fluidized-bed combustion, bit. = bituminous, CAES = compressed air energy storage, FO2 = fuel oil 2, lig. = lignite, MSW = municipal solid waste, NG = natural gas, PC-fired = pulverized-coal-fired, PFBC = pressurized fluidized-bed combustion, RDF = refuse-derived waste, RESID = residual fuel oil, STIG = steam injection gas turbine, sub. = subbituminous.

[b] Costs in 1994 dollars.

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