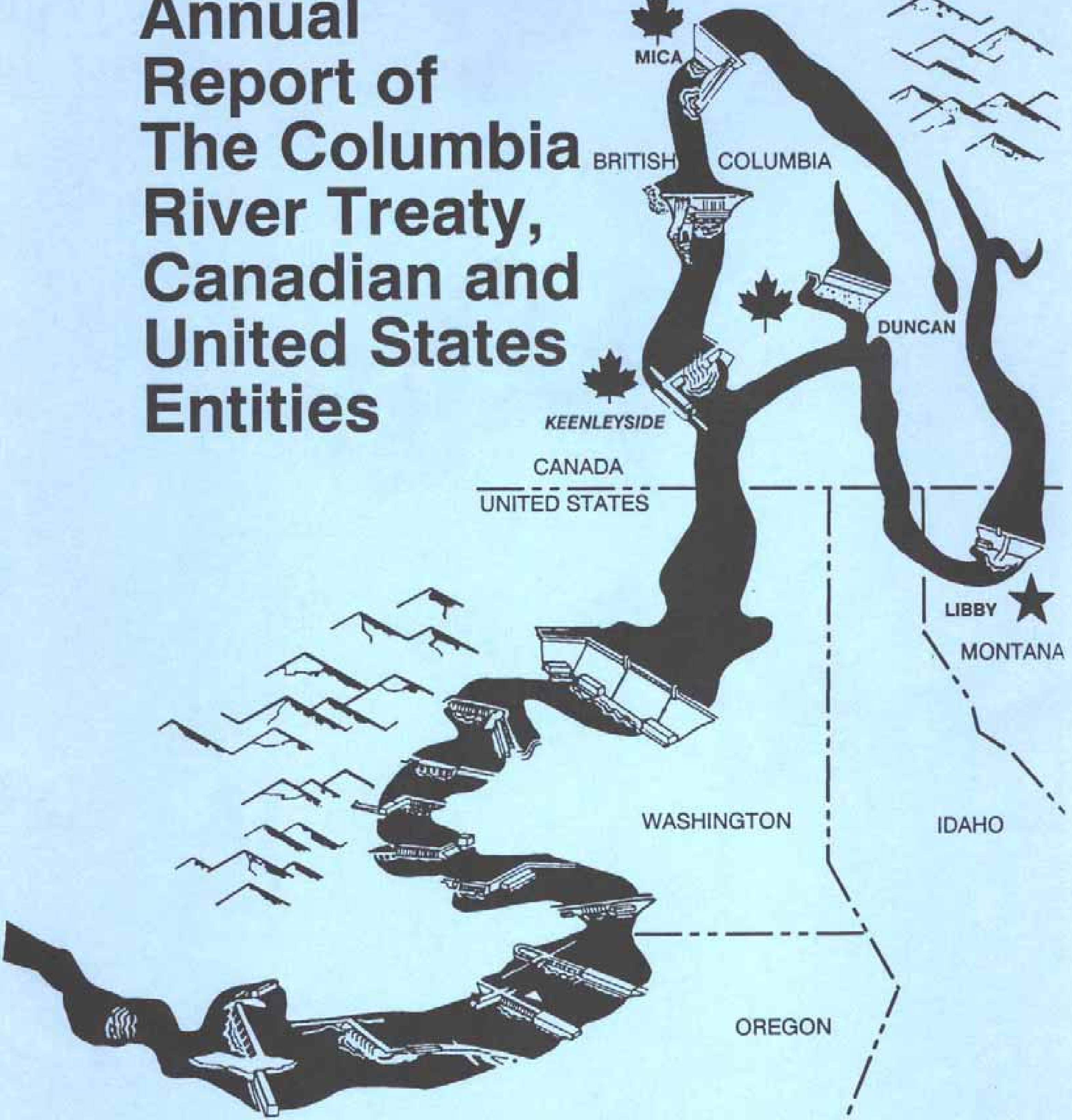
Annual Report of The Columbia River Treaty, Canadian and United States Entities



1 October 1991 through
30 September 1992

November 1992

ANNUAL REPORT OF
THE COLUMBIA RIVER TREATY
CANADIAN AND UNITED STATES ENTITIES

FOR THE PERIOD

1 OCTOBER 1991 - 30 SEPTEMBER 1992

Executive Summary

Entity Agreements

Agreements approved by the Entities during the period of this report include:

- Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1991 through 31 July 1992, dated November 1991.
- Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans for Canadian Storage, dated December 1991.
- The Assured Operating Plan, and Determination of Downstream Power Benefits for Operating Year 1996-97, dated February 1992.
- Entity Agreements on Aspects of the Canadian Entitlement Return for April 1, 1988 through March 31, 2003, executed 28 July 1992.

System Operation

The coordinated system filled to 99.6 percent of storage capacity by 31 July 1991. As a result, first year firm energy load carrying capability (FELCC) was adopted for the 1991-92 operating year. From September through December the system proportionally drafted to meet FELCC.

The 1 January water supply forecast for the Columbia River at The Dalles was 92.6 MAF, or 87 percent of average. This forecast indicated that secondary energy would be available. However, the Federal System was operated conservatively to ensure that about 3 MAF above the energy content curve (ECC) would be provided for the 1992 juvenile fish flow augmentation. Energy was purchased to keep the reservoirs (Grand Coulee and Arrow) above ECC. The spring remained dry and forecasted runoff continued to drop. The actual observed runoff was 70.4 MAF, or 66 percent of average and the eighth lowest since 1929.

The peak daily average flow observed at The Dalles was 232,300 cfs. The lower Columbia River was regulated in May and June to meet requests for fish flows delivering the Water Budget and Flow Augmentation volumes. The observed coordinated system storage content reached 76.1 percent of capacity on 31 July 1992. However, the energy content reached in the Actual Energy Regulation (AER) for Firm Energy Load Carrying Capability (FELCC) adoption was only 67.7 percent of full, and this value was used to determine Firm Energy Load Carrying Capability (FELCC) adoption for the 1992-93 operating year. Because the AER reached only 67.7 percent full, third year FELCC was adopted for the 1992-93 operating year. From 1 August 1991 through 31 March 1992 generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange Agreement, was approximately 318 average megawatts at rates up to 932 megawatts. From 1 April through 31 July 1992 the delivery was 305 average megawatts, at rates up to 844 megawatts. All CSPE power was used to meet Pacific Northwest loads.

Treaty Project Operation

The Treaty projects were operated throughout the year in accordance with the 1991-92 Detailed Operating Plan and the Flood Control Operating Plan.

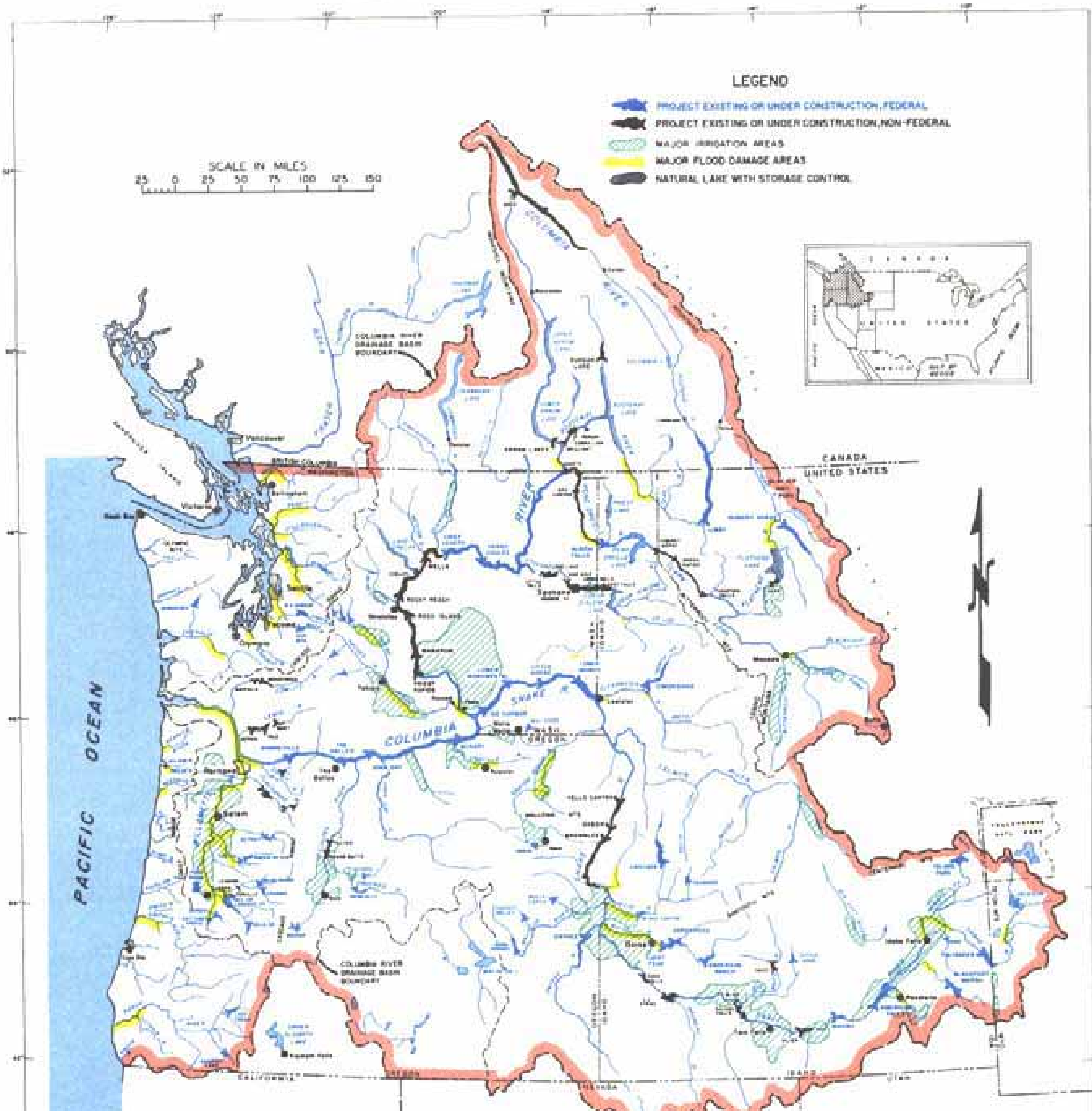
Mica treaty storage reached full content on 3 August 1991 when the reservoir elevation was 2473.16 feet. By 1 October the reservoir level had dropped to 2467.7 feet. The reservoir reached its lowest level, 2389.7 feet on 23 April 1992. Mica's maximum treaty storage content of 99.6% full (6.97 MAF) was reached on 21 August 1992. The maximum level for the operating year, 2451.8 feet, was reached on 7 August. This is 23 feet below full pool.

During the 1991 operating year, Arrow reached its maximum level of 1444.2 feet on 30 September 1991. The reservoir drafted throughout autumn and winter, reaching a minimum elevation of 1407.4 feet on 17 March. The maximum level in 1992 was elevation 1426.3 feet on 14 May. The reservoir then drafted to elevation 1407.2 feet on 28 June. After that date the releases were reduced for the purpose of increasing storage in the reservoir. However from mid-July through August a slow draft continued even though Mica releases were at near power house capacity. After Labor Day (7 September), Mica discharges were reduced to start correcting the overrun of Treaty water into Arrow.

Duncan reservoir completely filled during the 1991 operating year and surcharged to elevation 1892.7 feet on 10 August; it was back at full pool by 13 August. During October the project drafted to elevation 1880.3 feet by 29 October. Drawdown recommenced on 14 December to meet the 31 December flood control elevation of 1868.8 feet. Duncan reached its lowest level during the operating year, 1800.2 feet, on 10 April 1992. The reservoir reached its peak elevation of 1856.1 feet on 11 July. This is 36 feet below full, and the lowest-ever peak level in the history of the Duncan project. On July 18 the project began drafting again and reached elevation 1832.6 feet on 31 August; this was the result of a transfer of water from Duncan to Libby.

During the 1991 operating year, Libby reached full pool of 2459.0 feet on 7 July 1991. The reservoir began being drawn down on 3 September, and by 31 December it had reached elevation 2369.2 feet. A minimum level of 2362.2 feet was reached on 14 March. The reservoir reached its highest elevation of 2439.9 feet on 10 August; nearly 20 feet below full. The project then drafted to elevation 2934.5 feet by 9 September 1992.

COLUMBIA RIVER AND COASTAL BASINS



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1992 Report of The Columbia River Treaty Entities
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I Introduction

This annual Columbia River Treaty Entity Report is for the 1992 Water Year, 1 October 1991 through 30 September 1992. It includes information on the operation of Mica, Arrow, Duncan, and Libby reservoirs during that period with additional information covering the reservoir system operating year, 1 August 1991 through 31 July 1992. The power and flood control effects downstream in Canada and the United States are described. This report is the twenty-sixth of a series of annual reports covering the period since the ratification of the Columbia River Treaty in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the United States of America were constructed under the provisions of the Columbia River Treaty of January 1961. Treaty storage in Canada is required to be operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the United States of America. In 1964, the Canadian and the United States governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the Treaty. The Canadian Entity is the British Columbia Hydro and Power Authority (B.C. Hydro). The United States Entity is the Administrator of the Bonneville Power Administration (BPA) and the Division Engineer of the North Pacific Division, Army Corps of Engineers (ACE).

The following is a summary of key features of the Treaty and related documents:

1. Canada is to provide 15.5 million acre-feet (maf) of usable storage. (This has been accomplished with 7.0 maf in Mica, 7.1 maf in Arrow and 1.4 maf in Duncan.)

2. For the purpose of computing downstream benefits the U.S. hydroelectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian storage.

3. The U.S. and Canada are to share equally the additional power generated in the U.S. resulting from operation of the Canadian storage.

4. The U.S. paid Canada a lump sum of the $64.4 million (U.S.) for expected flood control benefits in the U.S. resulting from operation of the Canadian storage.

5. The U.S. has the option of requesting the evacuation of additional flood control space above that specified in the Treaty, for a payment of $1.875 million (U.S.) for each of the first four requests for this "on-call" storage.

6. The U.S. constructed Libby Dam with a reservoir that extends 42 miles into Canada and for which Canada made the land available.

7. Both Canada and the United States have the right to make diversions of water for consumptive uses and, in addition, after September 1984 Canada has the option of making for power purposes specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty which cannot be resolved by the two countries may be referred to either the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.

9. The Treaty shall remain in force for at least 60 years from its date of ratification, 16 September 1964.

10. In the Canadian Entitlement Purchase Agreement of 13 August 1964, Canada sold its entitlement to downstream power benefits to the United States for 30-years beginning at Duncan on 1 April 1968, at Arrow on 1 April 1969, and at Mica on 1 April 1973.

11. Canada and the U.S. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a Permanent Engineering Board (PEB) to review and report on operations under the Treaty.

II Treaty Organization

Entities

There was one meeting of the Columbia River Treaty Entities (including the Canadian Entity Representative and U.S. Coordinators) during the year on the morning of 3 December 1991 in Portland, Oregon. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY	CANADIAN ENTITY
Mr. Randall W. Hardy, Chairman Administrator, Bonneville Power Administration Department of Energy Portland, Oregon	Mr. J. Norman Olsen, Chairman Chairman, British Columbia Hydro and Power Vancouver, B.C.
Major General Ernest J. Harrell Division Engineer North Pacific Division Army Corps of Engineers Portland, Oregon	

Mr. Hardy was appointed to succeed Mr. Jack Robertson on 22 November 1991. Mr. Olsen succeeded Mr. Bob Wyman effective 25 June 1992.

The Entities have appointed Coordinators and a Representative and two joint standing committees to assist in Treaty implementation activities. These are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the Treaty and related documents are:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the Treaty.
2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services.
3. Operate a hydrometeorological system.
4. Assist and cooperate with the Permanent Engineering Board in the discharge of its functions.
5. Prepare hydroelectric and flood control operating plans for the use of Canadian storage.

6. Prepare and implement detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under assured operating plans.

7. The Treaty provides that the two governments may, by an exchange of notes, empower or charge the Entities with any other matter coming within the scope of the Treaty.

Entity Coordinators and Representative

The Entities have appointed members of their respective staffs to serve as coordinators or focal points on Treaty matters within their organizations.

The members are:

UNITED STATES ENTITY COORDINATORS

Edward W. Sienkiewicz, Coordinator
Senior Asst. Administrator for Power
Management, Bonneville Power
Administration, Portland, Oregon

Robert P. Flanagan, Coordinator
Director, Planning and Engineering
North Pacific Division
Army Corps of Engineers
Portland, Oregon

Pamela A. Kingsbury, Secretary
Energy Resource Specialist, Hydro Canadian
Section
Division of Power Resources
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY REPRESENTATIVE

Douglas R. Forrest, Manager
Canadian Entity Services
B.C. Power Exchange Corporation
Vancouver, B.C.

Columbia River Treaty Operating Committee

The Operating Committee was established in September 1968 by the Entities and is responsible for preparing and implementing operating plans as required by the Columbia River Treaty, making studies and otherwise assisting the Entities as needed. The Operating Committee consists of eight members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Robert D. Griffin, BPA, Co-Chairman	Timothy J. Newton, BCH, Chairman
Nicholas A. Dodge, ACE, Co-Chairman	Ralph D. Legge, BCH
Russell L. George, ACE	Kenneth R. Spafford, BCH
Steven A. Montfort, BPA	Gary H. Young, BCH

Mr. Montfort was appointed to succeed John M. Hyde, effective 8 May 1992.

There were six meetings of the Operating Committee during the year. The dates, places and number of persons attending those meetings were:

Date	Location	Attendees
13 November 1991	Vancouver, B.C.	16
15 January 1992	Portland, OR.	18
19 March 1992	Vancouver, B.C.	17
19 May 1992	Dworshak Dam, Idaho	17
16 July 1992	Vancouver, B.C.	19
9 September 1992	Vancouver, WA	15

The Operating Committee coordinated the operation of the Treaty storage in accordance with the current hydroelectric and flood control operating plans. This aspect of the Committee's work is described in following sections of this report which has been prepared by the Committee with the assistance of others. During the period covered by this report, the Operating Committee completed the 1991-92 Detailed Operating Plan (DOP), and completed the 1996-97 Assured Operating Plan.

Columbia River Treaty Hydrometeorological Committee

The Hydrometeorological Committee was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accord with the Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Bruce E. MacKay, BPA Co-Chairman	William Chin, BCH, Chairman
Douglas D. Speers, ACE, Co-Chairman	Brian H. Fast, BCH, Member

Mr. MacKay was appointed to succeed Mr. Richard Watt on 8 May 1992. There was one meeting of the Hydrometeorological Committee, on 31 October in Vancouver, B.C. The committee reviewed the 1991 volume forecast results, hydromet station changes, and developments in telemetry and forecast procedures. It also addressed the revision made in the discharge rating curves for Keenleyside project. In general, data was exchanged smoothly with no major problems.

Permanent Engineering Board

Provisions for the establishment of the Permanent Engineering Board (PEB) and its duties and responsibilities are included in the Treaty and related documents. The members of the PEB are presently:

UNITED STATES SECTION
Herbert H. Kennon, Chairman,
Washington, D.C.
Ronald H. Wilkerson, Member
Missoula, Montana

John P. Elmore, Alternate
Washington, D.C.
Thomas L. Weaver, Alternate
Golden, Colorado
S.A. Zanganeh, Secretary
Washington, D.C.

CANADIAN SECTION
David Oulton, Chairman
Ottawa, Ontario
John Allen, Member
Victoria, B.C.

Don A. Kasianchuk, Alternate
Victoria, B.C.
E.M. Clark, Alternate & Secretary
Vancouver, B.C.

Mr. Oulton succeeded Mr. Gordon MacNabb effective 19 November 1991.

In general, the duties and responsibilities of the PEB are to assemble records of flows of the Columbia River and the Kootenay River at the international boundary; report to both governments if there is deviation from the hydroelectric or flood control operating plans, and if appropriate, include recommendations for remedial action; assist in reconciling differences that may arise between the Entities; make periodic inspections and obtain reports as needed from the Entities to assure that Treaty objectives are being met; make an annual report to both governments and special reports when appropriate; consult with the Entities in the establishment and operation of a hydrometeorological system; and, investigate and report on any other Treaty related matter at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, downstream power benefit computations, corrections to hydrometeorological documents, and the annual Entity report to the Board for their review. The annual joint meeting of the PEB and the Entities was held on the afternoon of 3 December 1991 in Portland, Oregon. A special joint meeting of the PEB and the Entities was held on 14 September 1992 in Vancouver, B.C., to discuss the Entities' positions on the computation of capacity credit limits.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM at the end of the period of this report were:

UNITED STATES SECTION

S.A. Zanganeh, Chairman
Washington, D.C.
Gary L. Fuqua, Member
Portland, Oregon
Earl E. Eiker, Member
Washington, D.C.
Larry Eilts, Member
Golden, Colorado
Stephen J. Wright, Alternate Member
Washington, D.C.
Richard L. Mittelstadt, Alternate Member
Portland, Oregon

CANADIAN SECTION

R.O. "Neil" Lyons, Chairman
Vancouver, B.C.
David Burpee, Member
Ottawa, Ont.
Roger McLaughlin, Member
Victoria, B.C.
Robin Round, Member
Victoria, B.C.

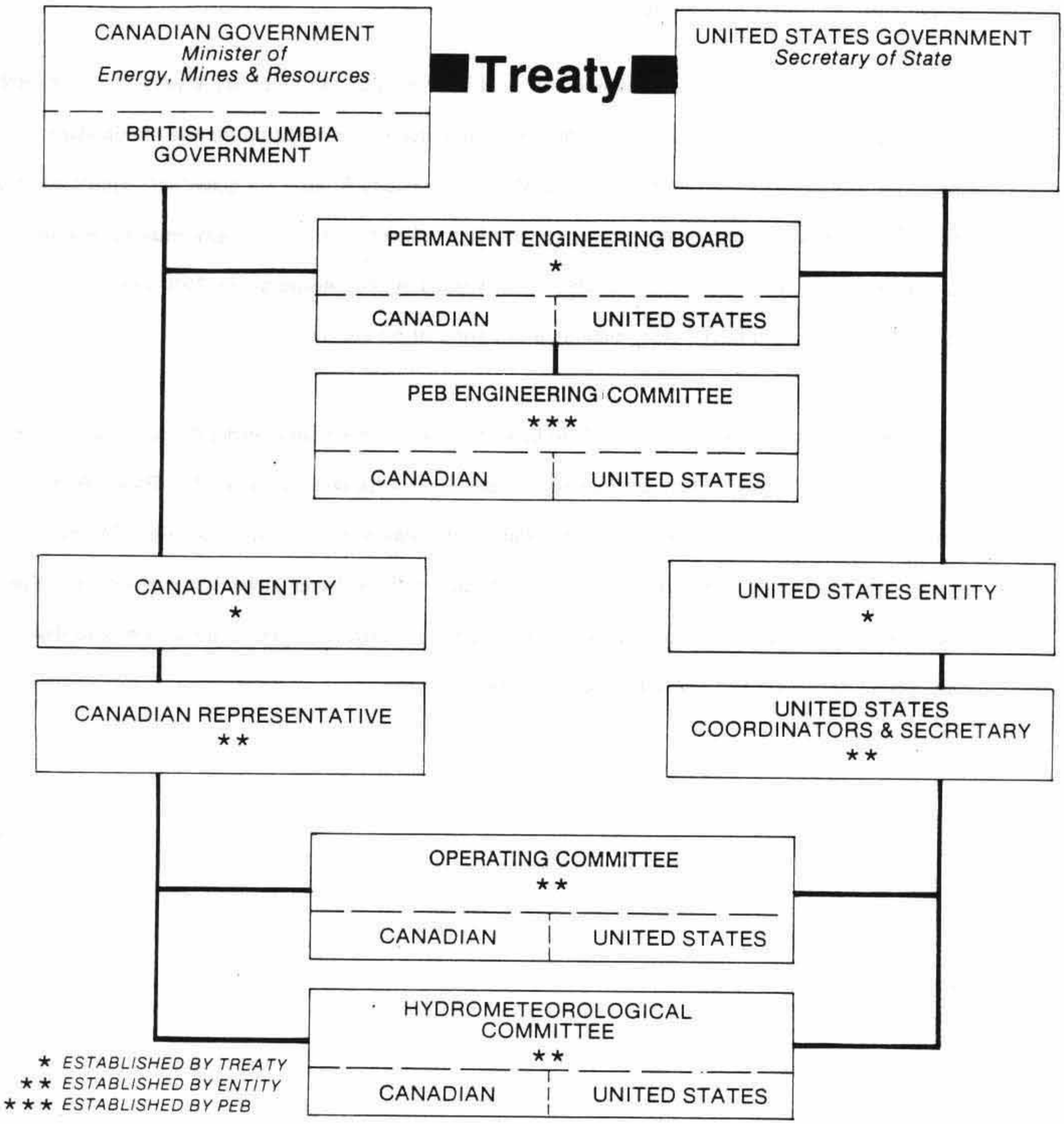
Mr. Mittelstadt was appointed as an alternate member of the US Section on 1 October 1991, replacing Mr. D. Wingerd. Messrs. Burpee, McLaughlin, and Round replaced Messrs. Stipdonk and McCauley prior to 30 September 1992.

International Joint Commission

The International Joint Commission (IJC) was created under the Boundary Waters Treaty of 1909 between Canada and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If a dispute concerning the Columbia River Treaty could not be resolved by the Entities or the PEB it may be referred to the IJC for resolution before being submitted to a tribunal for arbitration.

The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC currently informed. There are four such boards west of the continental divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, the International Osoyoos Lake Board of Control and the International Skagit River Board of Control. The Entities and their committees conducted their Treaty activities during the period of this report so that there was no known conflict with IJC orders or rules.

Columbia River Treaty Organization



III Operating Arrangements

Power and Flood Control Operating Plans

The Columbia River Treaty requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty stipulates that the United States Entity will submit flood control operating plans and that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not be adverse to the desired aim of the flood control plan. Annex A also provides for the development of hydroelectric operating plans five years in advance to furnish the Entities with an Assured Operating Plan for Canadian storage. In addition, Article XIV.2.k of the Treaty provides that a Detailed Operating Plan may be developed to produce more advantageous results through the use of current estimates of loads and resources. The Protocol to the Treaty provides further detail and clarification of the principles and requirements of the Treaty.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans" dated December 1991 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1972, establish and explain the general criteria used to plan and operate Treaty storage during the period covered by this report. These documents were previously approved by the Entities.

The planning and operation of Treaty Storage as discussed on the following pages is for the operating year, 1 August through 31 July. The planning and operating for U.S. storage operated according to the Pacific Northwest Coordination Agreement has been changed to the same period. Most of the hydrographs and reservoir charts in this report are for a 13 month period, July 1991 through July 1992.

Assured Operating Plan

The Assured Operating Plan (AOP) dated November 1986 established Operating Rule Curves for Duncan, Arrow, and Mica during the 1991-92 operating year. The Operating Rule Curves provided guidelines for draft and refill. They were derived from Critical Rule Curves, Assured Refill Curves, Upper Rule Curves, and Variable Refill Curves, consistent with flood control requirements, as described in the 1991 Principles and Procedures document. The Flood Control Storage Reservation Curves were established to conform to the Flood Control Operating Plan of 1972.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits resulting from Canadian Treaty storage is made five years in advance in conjunction with the Assured Operating Plan. For operating year 1991-92 the estimate of benefits resulting from operating plans designed to achieve optimum operation in both countries was less than that which would have prevailed from an optimum operation in the United States only. Therefore, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement, the Entities agreed that the United States was entitled to receive 3.5 average megawatts of energy during the period 1 August 1991 through 31 March 1992. For operating year 1992-93, the estimate of benefits resulting from operating plans designed to achieve optimum operation in both countries indicated no loss, therefore no energy delivery was required during the period 1 April through 31 July 1992. Suitable arrangements were made between the Bonneville Power Administration and B.C. Hydro for delivery of this energy. Computations indicated no loss or gain in dependable capacity during the 1991-92 operating year.

Detailed Operating Plan

During the period covered by this report, storage operations were implemented by the Operating Committee in accordance with the "Detailed Operating Plan for Columbia River Treaty Storage" (DOP), dated November 1991. The DOP established criteria for determining the Operating Rule Curves for use in actual operations. Except for minor changes at Arrow during the spring months, the DOP used the AOP critical rule curves for Canadian Projects. The Variable Refill Curves and flood control requirements subsequent to 1 January 1992 were determined on the basis of seasonal volume runoff forecasts during actual operation. Results of the Actual Energy Regulation were used to determine the triggering of high releases from Mica. The regulation of the Canadian storage was conducted by the Operating Committee on a weekly basis throughout the year.

Entity Agreements

During the period covered by this report, four agreements were officially approved by the Entities. The following tabulation indicates the date each of these were signed and gives a description of the agreement:

Date Agreement Signed by Entities	Description
20 November 1991	Detailed Operating Plan on Columbia River Treaty Storage, 1 August 1991 through 31 July 1992, dated November 1991.
13 December 1991	Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans for Canadian Storage, dated December 1991.
3 March 1992	Assured Operating Plan, Determination of Downstream Power Benefits for Operating Year 1996-1997, dated February 1992.
28 July 1992	Entity Agreement on Aspects of the Canadian Entitlement Return for 1 April 1998 through 31 March 2003.

Long Term Non-Treaty Storage Contract

In accordance with the 9 July 1990 Entity Agreement which approved the contract between B.C. Hydro and BPA relating to the initial filling of non-Treaty storage, coordinated use of non-Treaty storage, and Mica and Arrow refill enhancement, the Operating Committee monitored the storage operations made under this Agreement throughout the last year to insure that they did not adversely impact operation of Treaty storage required by the Detailed Operating Plan.

IV Weather and Streamflow

Weather

The weather during the Operational Year '92 was drier and warmer than normal, the result of typical winter storms being diverted around the Pacific Northwest. This redirection of the storm paths was similar to those that occurred during previous El Niño/Southern Oscillation (ENSO) episodes. During the ENSO occurrences the global weather patterns are shifted, replacing the winter Aleutian low pressure system with a high pressure system located near or on the coast of Oregon and Washington. This high blocks the storms from entering the Pacific Northwest and redirects them into either California or British Columbia. As the northern storms move around the high and into the central U. S., they cross over the Canadian portions of the Columbia drainage, producing more precipitation than in the rest of the basin. Similarly, some of the storms entering California may either brush the southern portion of Oregon or curve northeastward, crossing the headwaters of the Snake basin in eastern Idaho and creating more precipitation in the areas along the southern and eastern borders than in the remainder of the basin.

The year began, however, with more typical weather (Charts 1-3). August had near normal temperatures throughout the basin and near normal precipitation in the north and dry weather in the Snake and other southern basins. September was warmer than normal with near normal shower activity for the first half of the month, followed by 2 warm/dry weeks. This warm/dry pattern continued through the first 2 weeks of October when, as typically happens each year at this time, the coastal high pressure ridge was displaced by a low pressure system. The storms associated with this low produced shower activities across the Northwest and moderate precipitation on the 25-27th, followed by residual showers for the remainder of the month. This standard winter weather regime continued through mid-December, producing normal precipitation in the Columbia River Basin above The Dalles. At this time, the shift in the global weather patterns (attributed to ENSO) brought a blocking high pressure ridge onto the coast of

Oregon and Washington, splitting both the storm paths and the high elevation jet stream and sending some of the storm into California and others into British Columbia.

In general, this pattern remained through the end of the operational year. Although this high pressure was occasionally penetrated by storms, it always rebuilt after a few days to keep a majority of the storms from the center of the Columbia drainage and prevented the building of normal snowpack and warm temperatures promoted their early melting (Charts 4 and 5). Basin temperatures averaged 10°F above normal and precipitation averaged about one-half of normal from mid-December through mid-June, with the exception of the first half of April. During this period the blocking high was temporarily displaced by the Aleutian low, producing normal temperatures and precipitation over the basin. Just before the low again gave way to the blocking high, an intense storm entered the basin producing heavy precipitation to exceed the normal for the rest of the month. From mid-June through July, high temperatures and pockets of moisture produced showers that exceeded the normal monthly precipitation. However, since the summer season normal precipitation values are very low compared with winter months, the high percentages of normal have little meaning, especially since the soil moisture was well below normal.

The final monthly precipitation indices for the Columbia Basin above The Dalles are shown below for the 1992 water year. These indices are based on 60 stations and are computed at the end of each month after all the data are collected. Also shown in the table are the monthly indices as a percent of the 30-year average (1961-1990).

WY 92 INDICES

MONTH	PRECIPITATION (in.)	PRECIPITATION (%)	MONTH	PRECIPITATION (in.)	PRECIPITATION (%)
OCT 91	1.16	71	APR 92	1.94	121
NOV 91	3.41	125	MAY 92	0.90	50
DEC 91	1.88	62	JUN 92	2.30	127
JAN 92	2.20	74	JUL 92	1.74	159
FEB 92	1.46	69	AUG 92	0.74	60
MAR 92	0.72	38	SEP 92	1.37	98
			WATER YEAR	20.07	86

Streamflow

The observed inflow and outflow hydrographs for the Treaty reservoirs for the period 1 July 1991 through 31 July 1992 are shown on Charts 6 through 9. Observed flows with the computed unregulated flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 10, 11, 12, and 13, respectively. Chart 14 is a hydrograph of observed and two unregulated flows at The Dalles during the April through July 1992 period, including a plot of flows occurring if regulated only by the Treaty reservoirs.

Streamflows in the basin above The Dalles were near normal for the composite operating year, with November, February, July, and August exceeding the norm. The October through September runoff for The Dalles was 67 percent of the 1961-90 average. The peak regulated discharge for the Columbia River at The Dalles was 232,300 cfs on 22 May 1992. The 1991-92 monthly natural streamflows and their percent of the 1961-90 average monthly flows are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These flows have been corrected for storage in lakes and reservoirs to exclude the effects of regulation.

	COLUMBIA RIVER AT GRAND COULEE IN CFS		COLUMBIA RIVER AT THE DALLES IN CFS	
TIME PERIOD	NATURAL FLOW	PERCENT OF AVERAGE	NATURAL FLOW	PERCENT OF AVERAGE
AUG 91	130,800	120	160,200	112
SEP 91	57,350	85	83,150	150
OCT 91	32,160	67	56,860	66
NOV 91	29,950	62	70,980	79
DEC 91	27,890	66	68,540	73
JAN 92	30,470	74	68,040	70
FEB 92	40,190	89	94,280	83
MAR 92	57,610	98	118,300	85
APR 92	108,700	93	179,200	82
MAY 92	212,200	81	303,100	73
JUN 92	202,900	62	263,000	54
JUL 92	117,600	61	150,400	59
YEAR	87,440	80	135,500	82

Seasonal Runoff Forecasts and Volumes

Observed 1992 April through August runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume In 1000 Acre-Feet	Percent of 1961-90 Average
Libby Reservoir Inflow	4456	70
Duncan Reservoir Inflow	1830	89
Mica Reservoir Inflow	10922	95
Arrow Reservoir Inflow	19627	84
Columbia River at Birchbank	33793	83
Grand Coulee Reservoir Inflow	42903	70
Snake River at Lower Granite Dam	9654	42
Columbia River at The Dalles	58904	63

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 1992 as usual for a large number of locations in the Columbia River Basin and updated each month as the season advanced. Table 1 lists the April through August volume inflow forecasts for Mica, Arrow, Duncan, and Libby projects, and for unregulated runoff for the Columbia River at The Dalles. Also shown in Table 1 are the actual volumes for these five locations. The forecasts for Mica, Arrow, and Duncan inflow were prepared by B.C. Hydro, and those for the lower Columbia River and Libby inflows were prepared by the U. S. Columbia River Forecasting Service. The 1 April 1992 forecast of January through July runoff for the Columbia River above The Dalles was 71.2 MAF and the actual observed runoff was 70.4 MAF.

The following tabulation summarizes monthly forecasts since 1970 of the January through July runoff for the Columbia River above The Dalles compared with the actual runoff measured in millions of acre-feet (MAF):

Year	Jan	Feb	Mar	Apr	May	June	Actual
1970	82.5	99.5	93.4	94.3	95.1		95.7
1971	110.9	129.5	126.0	134.0	133.0	135.0	137.5
1972	110.1	128.0	138.7	146.1	146.0	146.0	151.7
1973	93.1	90.5	84.7	83.0	80.4	78.7	71.2
1974	123.0	140.0	146.0	149.0	147.0	147.0	156.3
1975	96.1	106.2	114.7	116.7	115.2	113.0	112.4
1976	113.0	116.0	121.0	124.0	124.0	124.0	122.8
1977	75.7	62.2	55.9	58.1	53.8	57.4	53.8
1978	120.0	114.0	108.0	101.0	104.0	105.0	105.6
1979	88.0	78.6	93.0	87.3	89.7	89.7	83.1
1980	88.9	88.9	88.9	89.7	90.6	97.7	95.8
1981	106.0	84.7	84.5	81.9	83.2	95.9	103.4
1982	110.0	120.0	126.0	130.0	131.0	128.0	129.9
1983	110.0	108.0	113.0	121.0	121.0	119.0	118.7
1984	113.0	103.0	97.6	102.0	107.0	114.0	119.1
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3
1987	88.9	81.9	78.0	80.0	76.7	75.8	76.5
1988	79.2	74.8	72.7	74.0	76.1	75.0	73.7
1989	101.0	102.0	94.2	99.5	98.6	96.9	90.6
1990	86.5	101.0	104.0	96.0	96.0	99.5	99.7
1991	116.0	110.0	107.0	106.0	106.0	104.0	107.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4

V Reservoir Operation

General

The 1992 operating year was characterized by below average precipitation and above average temperatures in the September through March period. The snowmelt season was characterized by continued warm, dry conditions. At the Dalles, the observed January-July runoff was 66 percent of average, one percent lower than the April forecast, and twenty-one percent lower than the January forecast. This runoff volume was the lowest since 1977.

The operating year began with the coordinated reservoir system officially filling to 99.6 percent of storage capacity on 31 July 1991. As a result, first year firm energy load carrying capability (FELCC) was adopted for the 1991-92 operating year.

The system began September operating in accordance with proportional draft requirements. The system drafted between first and second year rule curves through December, and no secondary energy was sold.

The 1 January water supply forecast was 92.6 maf for the January-July period, or 87 percent of the 1961-90 average. Subsequent forecasts through April reflected a decreasing trend, with the April forecast 67 percent of average. The January, February, and March Actual Energy Regulations (AER) showed the system operating to ECC and not requiring proportional draft. However, BPA was purchasing energy to store up to 3 MAF in Grand Coulee and Arrow by 31 March for a subsequent flow augmentation release.

In April, the system was in proportional draft between second and third year critical rule curves, however, BPA had more than 3 MAF stored in the system above PDP. During the 15 April-15 June flow augmentation period, the Priest Rapids minimum target flow of 134,000 cfs was first reached on 6 May.

The May average outflow was 140,000 cfs, and the June average outflow was greater than 150,000 cfs. The subsequent flows at The Dalles were greater than 200,000 cfs and 180,000 cfs in May and June, respectively.

Daily flood control regulation was not required during the 1992 snow melt season. The year's observed peak flow at The Dalles was 232,300 cfs on 22 May. Last year's peak was 348,000 cfs. The system reached 67.7 percent of its full capacity in the Actual Energy Regulation (AER) on 31 July 1992, resulting in third-year FELCC to be adopted for the 1992-93 operating year.

Mica Reservoir

As shown in Chart 6, Mica reservoir (Kinbasket Lake) was at elevation 2472.8 feet, approximately 2 feet below the full pool elevation of 2475 feet on 31 July 1991. Treaty storage filled three days later, on 3 August. Mica reached full pool on 8 August and began spilling a day later as inflows remained well above average. On 10 August, high temperatures and heavy local rainfall resulted in the peak inflow for the year, 98,400 cfs. The reservoir surcharged to elevation 2475.85 feet, the highest level on record. The project discharge reached a high of 100,500 cfs, including spill of 50,000 cfs, for eight hours on 10 August. Project inflow remained greater than powerhouse capacity until 24 August, when the spill was terminated. Another rainstorm on 1 September triggered a rise in inflow to 52,800 cfs, but this event was contained in the reservoir with no spill.

Reservoir inflows receded quickly after 1 September, reaching approximately 10,000 cfs by the end of the month. The project was kept at full load, 40,000 cfs discharge, through most of September to correct the substantial underrun that had accumulated during the summer months. By 1 October, the reservoir level had dropped to elevation 2467.7 feet. On 1 October, the evacuation of Treaty storage began according to the Detailed Operating Plan, with about two feet of Treaty storage drafted during October for flood control.

Mica powerhouse discharges averaged about 23,000 cfs October through December, and the reservoir level dropped to elevation 2438.4 feet by 31 December. Treaty storage on that date was 5.1 MAF.

During January 1992, powerhouse discharges averaged 33,000 cfs, while discharges during February were slightly less, averaging about 29,000 cfs. The reservoir had drafted to elevation 2402.7 feet by 29 February 1992.

The reservoir continued to draft in March and most of April, although at a much reduced rate. Discharges during both months averaged approximately 15,000 cfs. The reservoir reached its lowest level for the 1992-92 season, elevation 2389.7 feet on 23 April. Mica Treaty storage reached a minimum of 1.4 MAF on 26 April.

In late April, a rainstorm hit the area, increasing inflows from approximately 10,000 cfs to over 40,000 cfs. This signalled the start of the spring freshet in the Mica basin. Inflows ranged from 20 to 55,000 cfs during May and from 40,000 to 75,000 cfs during June. The peak inflow for the year was 75,800 cfs on 13 June. Discharges during May-June averaged just over the DOP discharge of 10,000 cfs, and the reservoir had risen to elevation 2442.6 feet by 30 June.

In early July, inflows dropped substantially. In addition, Mica powerhouse releases were maximized to help mitigate the low Arrow reservoir level. The Mica reservoir continued to fill at a reduced rate during July and the first part of August, and reached its highest level for the year of only elevation 2451.8 (7 August), 23 feet below full pool. Treaty storage at Mica continued to fill after this date, reaching a maximum of 6.97 MAF (99.6 % of full) on 21 August.

Revelstoke Reservoir

During August 1991, reservoir inflows were unusually high, due primarily to the high Mica project discharges. The reservoir filled to full pool and began spilling on 9 August. On 10 August, the project discharge was increased to 114,500 cfs, including spill of 62,000 cfs, for abut eight hours. The spill damaged an access road to the project and caused significant bank sloughing. Spill at Revelstoke was gradually reduced as reservoir inflow receded and the project stopped spilling on 21 August.

During the remainder of the 1991-92 operating year, the Revelstoke project was generally operated as a run-of-river plant, with the reservoir level maintained within two feet of its normal full pool level, elevation 1880 feet. The reservoir was drawn down to elevation 1877 feet on two occasions during the winter to help meet system load and exchange obligations. There was no need to draw the reservoir down prior to the 1992 spring feshet, since the potential for high local inflows was substantially lower than in other years.

Arrow Reservoir

As shown in Chart 7, Arrow reservoir level was elevation 1441.4 feet on 31 July 1991. The Arrow Treaty storage account was considered to be fully refilled on 3 August. The project discharge was maintained at 60,000 cfs, instead of being increased to pass inflow, on 3-4 August to aid in the unloading of a nuclear reactor on the Columbia River below Priest Rapids Dam in Washington. On 10 August, inflow to Arrow reservoir increased significantly due to spill at Mica and Revelstoke, and the Arrow discharge was increased to 115,000 cfs on 13 August. Project outflow was reduced below inflow on 14 August to fill the Arrow Non-Treaty storage accounts - these accounts were filled by 25 August. The reservoir reached its maximum level for 1991, elevation 1444.2 feet on 30 September.

The reservoir was drafted approximately 5 feet during October and a further 3 feet in November. During the last half of December, discharges were increased steadily from 37,000 cfs to 72,000 cfs, resulting in substantial drafting of the reservoir. The 31 December reservoir level was elevation 1428.4 feet.

The snowpack in the upper Columbia basin was about average on 1 January 1992, and the heavy Arrow reservoir draft, begun in late December, continued through January. Discharges during January ranged from 50,000 to 105,000 cfs, and the 31 January reservoir level was elevation 1410.9 feet.

For the month of February, discharges were reduced significantly and the reservoir filled slightly, to elevation 1412.1 feet on 29 February. The project resumed drafting at that time, reaching a low level of elevation 1407.4 feet on 17 March.

During 18-26 March, discharges were held at 10,000 cfs to facilitate the setup of the Norns (Pass) Creek Fan Fish Studies. Between 26 March and 30 April, project discharges were held at 15,000 cfs to ensure that rainbow trout spawning on the fan occurred at low river levels. In addition, a total of 14 guidewall cables at Keenleyside Dam were replaced during this low-flow period. Low Arrow discharges during this period fit in with the U.S. Entity's plan for storage of "Flow Augmentation" water at Arrow. The Arrow reservoir level rose to elevation 1420.4 feet by 30 April.

On 1 May, the Arrow discharge was increased to 30,000 cfs. Due primarily to rainfall events during the first part of May, inflow to the reservoir was greater than 30,000 cfs, and the reservoir level continued to rise, reaching a high of elevation 1426.3 feet on 14 May. This level was substantially above the normal Arrow reservoir level for that time of year. A very low runoff volume forecast for the total Columbia River basin as a whole had lowered the allowable drawdown level of Arrow. Therefore, in mid-May, the Treaty discharge was increased to 45,000 cfs and again to 75,000 cfs by the end of the month to accomplish the drawdown.

In June, discharges were further increased to 90,000 cfs and finally, to 119,000 cfs on 14 June in order to draft all required storage from the Arrow reservoir by the end of June. During the high Keenleyside discharge, a discharge of 174,000 cfs was recorded at Birchbank, just upstream of Trail. Although the flood damage level is near 235,000 cfs, some flooding damage was reported along the river between Castlegar and Trail, and an immediate reduction in the Keenleyside discharge, to 104,000 cfs, was agreed upon. The reservoir hit its minimum level for the summer, elevation 1407.2 feet on 28 June.

Discharges were reduced below 30,000 cfs for the first two weeks of July, resulting in some recovery of the reservoir. However, from mid-July to the end of August, discharges ranged from 45,000 to 65,000 cfs, resulting in a slow draft of the reservoir even with the upstream Mica plant running at nearly full load to minimize the Arrow reservoir drawdown.

Daily discharges were held in the 10,000 to 20,000 cfs range during 1-3 September for an inspection of the energy dissipator structure at Keenleyside Dam. After Labor Day (7 September), Mica discharges were reduced to start correcting the substantial overrun of Treaty water into Arrow.

Duncan Reservoir

As shown in Chart 8, the Duncan reservoir reached its full pool elevation of 1892 feet on 1 August 1991. During August and September, project discharges were adjusted to match inflow and keep the reservoir within a foot of full pool. On 10 August, high temperatures and heavy rainfall increased the daily inflow to 15,900 cfs. The reservoir surcharged to elevation 1892.7 feet on that day, with the project discharge peaking at 13,000 cfs on the following day. However, the inflow soon receded and the reservoir was drawn down to nearly full pool by 13 August.

During most of October, the project discharge was held at 5,500 cfs, with the reservoir drafting to elevation 1880.3 feet by 29 October. There was no further drawdown from then until mid-December, as discharges averaged about 1,000 cfs to pass inflow.

Drawdown of the reservoir recommenced on 14 December, with discharges increased to 6,000 cfs for the remainder of the month. This resulted in a 31 December reservoir level of elevation 1868.8 feet, meeting the flood control requirement for that date. The Duncan reservoir continued to draft in January, February, and early March 1992 to provide flood control storage. Discharges averaged about 8,000 cfs during this time and the reservoir was drafted to elevation 1806.7 feet by 5 March. A further draft of the reservoir storage commenced on 28 March, and the reservoir reached its lowest point for the operating year, elevation 1800.2 feet on 10 April.

The Duncan discharge was reduced to minimum 100 cfs, on 24 April to begin filling the reservoir. The reservoir level reached elevation 1850.1 feet by 9 June. On that date, an agreement was signed to operate Duncan and Libby so as to effectively transfer stored water from Duncan to the Libby reservoir to enhance the recreational aspects of Libby for Canadian users. This resulted in Duncan discharges being increased to 10,000 cfs by 11 June. The reservoir continued to fill slowly, reaching elevation 1853.9 feet by the end of June. Discharges were reduced below 10,000 cfs for the first half of July, and the reservoir level reached its peak level for the operating year, elevation 1856.1 feet on 11 July. This peak level for the year was 36 feet below full pool, and was the lowest-ever peak over the history of the Duncan project. On 18 July, discharges were again increased to 10,000 cfs, and the reservoir drafted quickly to elevation 1838 feet by mid-August. Discharges were reduced to an average of 6,000 cfs for the last half of August, but the reservoir continued to draft, reaching elevation 1832.6 feet on 31 August. A total of 465.4 ksfd was transferred from Duncan to Libby under the Duncan-Libby Storage Transfer Agreement. Under the agreement, this water will be transferred back to the Duncan reservoir by 31 December 1992.

Libby Reservoir

As shown in Chart 9, Libby completely refilled following the 1991 runoff, with Lake Koocanusa reaching full pool on 27 July 1991. The reservoir remained in the top foot through August and started drafting on 3 September.

Lake Koocanusa was drafted rapidly from October and into early December, with the 5-unit powerhouse running near full level from 25 October through 12 December 1991. The elevation on 31 December was 2369.2 feet; this level was about 12 feet below the proportional draft point because of provisional draft. Inflows during the October-December period were 107 percent of average.

In January, water supply forecasts for the upper Columbia drainage were about 92% of average. Libby's forecast was 95 percent. This forecast combined with the heavy fall draft resulted in no additional draft being required to meet the 15 March flood control requirement of elevation 2368 feet. The Libby outflow remained at 4000 cfs from 4 January 1992 through 19 March when it was reduced to 3000 cfs to improve refill probabilities. The lake reached a low level of elevation 2362.2 feet on 14 March 1992. Weekly load factoring with about 6000 cfs outflow occurred from early April into early May. Warm weather in late April started the snowmelt runoff. The peak inflow of the season was only 36,000 cfs and very early in the season on 9 May 92. Due to the low runoff in the Columbia Basin, the system remained on proportional draft in May and June. In late May BPA requested an increase in Libby outflow, maintain a slow fill and not be above the PDP elevation of 2413 on 30 June. These increased flows combined with the forecast that Libby reservoir was not going to fill brought many complaints from the reservoir users in the U.S. and Canada, as well as from people who could not fish in the river below the dam.

In an attempt to improve the maximum level that the reservoir would reach, BC Hydro and BPA reached an agreement that permitted BC Hydro to store water in Libby reservoir. On 10 June 1992, the outflow was reduced to 4,000 cfs with BC Hydro replacing the Libby flow that BPA was requesting with flow from Arrow and/or Duncan. This arrangement continued into August allowing Libby reservoir to be filled to its maximum level, elevation 2439.8 feet on 4 August. At that time BC Hydro indicated that it would not be storing any more water in Libby. BPA's request for release from Libby in early August began to cause a draft of the reservoir. By Labor Day, 7 September, the reservoir had drafted slightly more than 5 feet to elevation 2435.1. The January-July observed runoff was 4646 kaf, 73 percent of average. This runoff volume was the fifth lowest in the 1928-78 period of record.

Kootenay Lake

As shown in Chart 10, the level of Kootenay Lake at Queens Bay was elevation 1746.3 feet on 31 July 1991. As inflow receded, the lake was drafted, with the level of Nelson reaching the summer IJC operating level of elevation 1743.32 feet on 26 August. Discharges were then reduced to pass inflow for the remainder of August.

For the month of September, the Kootenay Lake discharge was reduced to prevent spilling at the downstream Brilliant plant. This allowed the lake to fill to elevation 1745.2 feet by 2 October, and the Queens Bay level was then maintained below the autumn IJC operating level of elevation 1745.32 feet. Discharges from the lake during the October-December period averaged about 27,000 cfs.

Kootenay Lake began drafting according to the IJC curve in early January 1992, with average discharges during the January-March period of 19,000 cfs. The lake drafted below the IJC limit of elevation 1739.32 feet by 27 March, and reached its minimum level for 1992, elevation 1739.0 feet on 13 April.

In mid-April, local inflow to Kootenay Lake began to increase, and the lake filled to elevation 1741.4 feet by 30 April. Inflow during May-June averaged 37,000 cfs, peaking at 61,000 cfs on 7 May. The lake reached an initial peak level of elevation 1744.1 feet on 11 May. After a drop in the lake level in late May, the lake then reached its peak level for the year, elevation 1745.1 feet, on 6 June and again on 14 June. The maximum lake discharge for the year was 40,000 cfs during the period 5-16 June, resulting in only minor spill at all of the Kootenay River plants except for Brilliant.

The runoff began to recede in mid-June, and Kootenay Lake drafted quickly. The lake level at Nelson dropped below the IJC summer level of elevation 1743.32 feet on 10 July and the lake was then held below this level until the end of August. The average release in July-August was 23,000 cfs. On 1 September, the lake began filling again to the IJC autumn level.

Duncan-Libby Storage Transfer Agreement

This agreement was reached in June of 1992. BC Hydro and BPA agreed to store BC Hydro water in Libby. The agreement involved operating Duncan and Libby to transfer water from Duncan to Libby, so that Libby Reservoir would be at a higher elevation than it would have reached otherwise, and therfore enhance summer recreation for Canadian and U.S. users. Ultimately, 465.3 ksfd of water was transferred from Duncan to Libby. The water will be transferred back to Duncan reservoir by 31 December 1992.

On 4 June 1992 Libby project outflow reduced from 22,000 cfs and reached 4000 cfs by 10 June 1992. Concurrently, on 6 June, the Duncan outflow was increased from 100 cfs reaching 10,000 cfs by 11 June. The Libby outflow remained 4000 cfs until 4 August when Libby reached its maximum elevation of 2439.8 feet. Meanwhile the Duncan discharges continued to be 10,000 cfs through mid-August except for a two-week period in July when the discharge was reduced to 6000 cfs. The highest elevation Duncan reached was 1856.1 feet on 11 July.

VI Power and Flood Control Accomplishments

General

During the period covered by this report, Duncan, Arrow, Mica, and Libby reservoirs were operated in accordance with the Columbia River Treaty. Specifically, the operation of the reservoirs was governed by:

1. "Detailed Operating Plan for Columbia River Treaty Storage - 1 August 1991 through 31 July 1992," dated November 1991.
2. "Columbia River Treaty Flood Control Operating Plan," dated October 1972.

Consistent with all Detailed Operating Plans prepared since the installation of generation at Mica, the 1991-92 Detailed Operating Plan was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States, in accordance with paragraph 7 of Annex A of the Treaty. The 1991-92 Assured Operating Plan, prepared in 1986, was used as the basis for the preparation of the 1991-92 Detailed Operating Plan.

Power

The Canadian Entitlement to downstream power benefits from Duncan, Arrow and Mica for the 1991-92 operating year had been purchased in 1964 by the Columbia Storage Power Exchange (CSPE). In accordance with the Canadian Entitlement Exchange Agreement dated 13 August 1964, the U.S. Entity delivered capacity and energy to the CSPE participants. The generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange was 318 average megawatts, at rates up to 932 megawatts, from 1 August 1991 through 31 March 1992, and 305 average megawatts from 1 April through 31 July 1992.

The Coordinated System reservoirs began the operating year near full on 1 August 1991 which allowed the System to adopt a 1st year firm load carrying capability (FLCC) from the critical period studies. After operating near the Operating Rule Curve (ORC) during the fall and winter, low inflows caused the Coordinated System to proportionally draft from April through July to meet FLCC. The coordinated system proportional draft point (PDP) was between critical rule curves.

The following table shows the status of the energy stored in Coordinated System reservoirs at the end of each month compared to the ORC or PDP during the 1991-92 operating year. Normal full Coordinated System reservoir storage is approximately 63,700 megawatt-months (MWMo). All figures are 1000 MWMo.

END OF PERIOD ENERGY STORAGE

	Coordinated System			Canadian Treaty		
MONTH	ORC/PDP K-MWMos	Actual K-MWMos	Difference K-MWMos	ORC/PDP K-MWMos	Actual K-MWMos	Difference K-MWMos
Aug 91	62.2	61.8	-0.4	29.4	29.5	0.1
Sep 91	58.2	58.2	0.0	29.3	29.2	-0.1
Oct 91	51.2	52.3	1.1	20.4	20.4	0.0
Nov 91	46.1	46.8	0.7	17.4	17.3	-0.1
Dec 91	39.2	41.5	2.3	15.6	15.3	-0.3
Jan 92	28.9	35.1	6.2	8.5	9.3	0.8
Feb 92	21.4	32.1	10.7	5.2	8.9	3.7
Mar 92	19.4	27.7	8.3	4.2	6.8	2.6
Apr 92	22.3	30.2	7.9	2.6	8.6	6.0
May 92	29.9	40.4	10.5	7.7	11.2	3.5
Jun 92	41.1	46.0	4.9	11.7	12.0	0.3
Jul 92	43.6	47.9	4.3	15.6	14.1	-1.5

To provide flow enhancement for the endangered salmon, the U.S. implemented a 3 million acre feet (MAF) flow augmentation program developed by the Northwest Power Planning Council's Fish and Wildlife program. During 1 January through 30 April, up to a maximum of 5.75 MAF was stored above the ORC/PDP in Arrow and Grand Coulee combined. The flow augmentation program kept the Coordinated System well above PDP January through May and provided higher flows for fish in June.

BPA developed and implemented an extensive purchasing strategy to meet projected energy deficits, provide for flow augmentation and other nonpower constraints, and enhance reservoir refill during an extremely low water year. The following table is a summary of the federal purchases (in average MW) in addition to those provided in the operating plan that were made from August 1991 through July 1992.

FEDERAL PURCHASES (aMW)

Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul
125	392	303	454	577	1011	2095	682	654	0	96	1235

Beginning in June, the U.S. and Canadian entities agreed to reservoir balance between Libby and Canadian treaty water. During June and July, Libby was operated on minimum discharge while Canadian treaty storage was drafted to make up the difference. The purpose for the reservoir balancing was to increase Lake Koocanusa elevation for recreational opportunities in both Canada and the U.S.

The following table shows BPA nonfirm and surplus sales in megawatt hours (MWh) to Northwest and Southwest utilities during the 1991-92 operating year.

BPA NONFIRM AND SURPLUS SALES (MWh)

PERIOD	TO NORTHWEST UTILITIES		TO SOUTHWEST UTILITIES	
	NONFIRM	SURPLUS FIRM	NONFIRM	SURPLUS FIRM
AUG 91	194,490	8,800	387,152	0
SEP 91	0	41,840	0	128,249
OCT 91	0	142,177	0	118,013
NOV 91	0	150,840	0	103,213
DEC 91	0	151,968	0	93,352
JAN 92	0	111,600	0	105,654
FEB 92	0	104,400	0	105,486
MAR 92	0	98,188	0	104,536
APR 92	0	0	0	83,280
MAY 92	670,428	0	2,604,180	423,675
JUN 92	560,740	0	400,538	89,249
JUL 92	0	0	0	133,935
TOTAL	1,425,658	809,813	3,391,870	1,488,642

Flood Control

The Columbia River Basin reservoir system, including the Columbia River Treaty projects, was not operated on a daily basis for flood control in the spring of 1992. The observed and unregulated hydrographs for the Columbia River at The Dalles between 1 April 1992 and 31 July 1992 are shown on Chart 14. The unregulated peak flow at The Dalles would have been 328,350 cfs on 11 May 1992 and it was controlled to a maximum of 232,300 cfs on 22 May 1992.

The observed peak stage at Vancouver, Washington was 9.39 feet on 22 February 1992 and the unregulated stage would have been 11.03 feet on 12 May 1992. Chart 15 documents the relative filling of Arrow and Grand Coulee during the principal filling period, and compares the regulation of these two reservoirs to guidelines in the Treaty Flood Control Operating Plan. Because the runoff volume forecast was small, flood control requirements were relieved at Arrow after 30 April, this curve did not guide operation after that date.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. Computed Initial Controlled Flows at The Dalles were 292,000 cfs on 1 January 1992, 288,000 cfs on 1 February, 252,000 cfs on 1 March, 200,000 cfs on 1 April and 200,000 cfs on 1 April, and 200,000 cfs on 1 May. As mentioned earlier, the observed peak flow at The Dalles was 232,300 cfs. Data for the 1 May ICF computation are given in Table 6.

Table 1

Unregulated Runoff Volume Forecasts
Million of Acre-Feet
1992

Forecast Date - 1st of	DUNCAN Most Probable 1 April - 31 August	ARROW Most Probable 1 April - 31 August	MICA Most Probable 1 April - 31 August	LIBBY Most Probable 1 April - 31 August	UNREGULATED RUNOFF COLUMBIA RIVER AT THE DALLES,OREGON Most Probable 1 April - 31 August
January	1.9	21.5	10.8	6.0	81.5
February	2.0.	23.4.	12.3.	6.1	79.3
March	2.0	22.5	11.5	5.7	73.5
April	1.9	20.4	10.8	5.0	60.1
May	2.0	21.3	11.1	5.3	60.1
June	2.0	20.9	11.4	4.5	56.4
Actual	1.8	19.6	10.9	4.5	58.9

NOTE: These data were used in actual operations. Subsequent revisions have been made in some cases.

TABLE 2
Variable Refill Curve
Mica Reservoir

	INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN1-31JULY INFLOW,KAF		8855.4	9894.9	9249.7	8513.6	8142.4	8142.4
& IN KSFD		4464.4	4988.7	4663.4	4292.3	4105.1	4105.1
95% FORECAST ERROR FOR DATE,IN KSFD		682.7	551.3	513.4	460.4	440.9	440.9
95% CONF.DATE-31JULY INFLOW,KSFD 2/		3781.9	4437.4	4150.0	3831.9	3664.2	3664.2
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.		100.00					
ASSUMED FEB1-JUL31 INFLOW,KSFD 4/		3781.9					
MIN FEB1-JUL31 OUTFLOW,KSFD		2269.8					
MIN JAN31 RESERVOIR CONTENT,KSFD 5/		2017.1					
MIN JAN31 RESERVOIR CONTENT,FEET 6/		2440.1					
JAN31 ECC,FT. 7/------------------>		2438.8					
BASE ECC, FT......................	2438.7						
LOWER LIMIT, FT 1/................	2416.9						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.		97.70	97.70				
ASSUMED MAR1-JUL31 INFLOW,KSFD 4/		3694.9	4335.4				
MIN MAR1-JUL31 OUTFLOW,KSFD		1849.8	1863.9				
MIN FEB28 RESERVOIR CONTENT,KSFD 5/		1684.1	1057.8				
MIN FEB28 RESERVOIR CONTENT,FEET 6/		2433.0	2419.3				
FEB28 ECC,FT. 7/------------------>		2426.8	2419.3				
BASE ECC, FT......................	2426.8						
LOWER LIMIT, FT 1/................	2402.4						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.		95.30	95.30	97.50			
ASSUMED APR1-JUL31 INFLOW,KSFD 4/		3604.2	4228.9	4046.3			
MIN APR1-JUL31 OUTFLOW,KSFD		1384.8	1398.9	1423.5			
MIN MAR31 RESERVOIR CONTENT,KSFD 5/		1309.9	699.3	906.4			
MIN MAR31 RESERVOIR CONTENT,FEET 6/		2424.9	2411.1	2415.3			
MAR31 ECC,FT. 7/------------------>		2416.5	2411.1	2415.3			
BASE ECC, FT......................	2416.5						
LOWER LIMIT, FT 1/................	2394.1						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.		90.40	90.40	92.40	94.80		
ASSUMED MAY1-JUL31 INFLOW,KSFD 4/		3418.8	4011.4	3834.6	3632.6		
MIN MAY1-JUL31 OUTFLOW,KSFD		1001.7	1014.5	1036.9	1160.2		
MIN APR30 RESERVOIR CONTENT,KSFD 5/		1112.0	532.3	731.5	1056.8		
MIN APR30 RESERVOIR CONTENT,FEET 6/		2420.5	2407.1	2411.7	2419.2		
APR30 ECC,FT. 7/------------------>		2406.1	2407.1	2406.1	2406.1		
BASE ECC, FT......................	2406.1						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.		72.60	72.60	74.20	76.00	80.20	
ASSUMED JUN1-JUL31 INFLOW,KSFD 4/		2745.7	3221.6	3079.3	2912.2	2938.7	
MIN JUN1-JUL31 OUTFLOW,KSFD		674.8	685.0	702.8	800.6	800.6	
MIN MAY31 RESERVOIR CONTENT,KSFD 5/		1458.3	992.6	1152.7	1417.6	1391.1	
MIN MAY31 RESERVOIR CONTENT,FEET 6/		2428.1	2417.8	2421.3	2427.2	2426.6	
MAY31 ECC,FT. 7/------------------>		2411.7	2411.8	2411.8	2411.8	2411.8	
BASE ECC, FT......................	2411.7						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.		35.90	35.90	36.70	37.60	39.70	49.50
ASSUMED JUL1-JUL31 INFLOW,KSFD 4/		1357.9	1593.0	1523.1	1440.8	1454.7	1364.5
MIN JUL1-JUL31 OUTFLOW,KSFD		358.7	366.1	379.4	452.6	452.6	452.6
MIN JUN30 RESERVOIR CONTENT,KSFD 5/		2530.0	2302.3	2356.5	2541.0	2527.1	2617.3
MIN JUN30 RESERVOIR CONTENT,FEET 6/		2450.6	2446.0	2447.0	2450.7	2450.5	2443.1
JUN30 ECC,FT. 7/------------------>		2443.1	2443.1	2443.1	2443.1	2443.1	2443.1
BASE ECC, FT......................	2443.1						
JUL 31 ECC, FT..................		2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

1/ FOR ARROW AND DUNCAN: THE LOWER LIMIT WILL BE THE HIGHER OF THE ELEVATION NEEDED TO PROTECT AGAINST A RECURRENCE OF 1936-37 STREAMFLOWS OF THE PREVIOUS MONTH (V)ECC LESS THE QUANTITY ONE FOOT TINES THE NUMBER OF DAYS IN THE CURRENT MONTH. FOR MICA: THE LOWER LIMIT WILL BE THE ELEVATION NEEDED TO PROTECT AGAINST A RECURRENCE OF 1936-37 STREAMFLOWS.

2/ LINE 1 MINUS LINE 2.....3/ LINE 3 MINUS LINE 4.....4/ PRECEDING LINE X LINE 5

5/ FULL CONTENT (3529.2 KSFD) PLUS LINE PRECEDING THAT LESS LINE PRECEDING THAT.

6/ FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE. DATED FEB 21, 1973.

7/ LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR.

TABLE 3
Variable Refill Curve
Arrow Reservoir

	INITIAL	JAN 1 LOCAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 LOCAL	MAY 1 LOCAL	JUN 1 LOCAL
PROBABLE JAN1-31JULY INFLOW,KAF		8999.4	20342	19268	8766.7	8139.4	8139.4
& IN KSFD		4537.2	10256	9714.4	4419.9	4103.6	4103.6
95% FORECAST ERROR FOR DATE,IN KSFD		822.5	1042.0	940.4	474.5	278.2	278.2
95% CONF.DATE-31JULY INFLOW,KSFD 2/		3714.7	9214.0	8774.0	3945.4	3645.9	3645.9
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.		100.00					
ASSUMED FEB1-JUL31 INFLOW,KSFD 4/		3714.7					
MIN FEB1-JUL31 OUTFLOW,KSFD		2736.8					
MICA REFILL REQUIREMENTS, KSFD 8/		2269.8					
MIN JAN31 RESERVOIR CONTENT,KSFD 5/		331.9					
MIN JAN31 RESERVOIR CONTENT,FEET 6/		1385.8					
JAN31 ECC,FT. 7/------------------>		1409.9					
BASE ECC, FT.......................	1423.8						
LOWER LIMIT, FT 1/.................	1409.9						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.		97.00	97.20				
ASSUMED MAR1-JUL31 INFLOW,KSFD 4/		3603.3	8956.0				
MIN MAR1-JUL31 OUTFLOW,KSFD		2596.8	2725.9				
MICA REFILL REQUIREMENTS, KSFD 8/		1849.8	2471.5				
MIN FEB28 RESERVOIR CONTENT,KSFD 5/		723.3	-179.1				
MIN FEB28 RESERVOIR CONTENT,FEET 6/		1394.1	1377.9				
FEB28 ECC,FT. 7/------------------>		1394.1	1393.9				
BASE ECC, FT.......................	1407.0						
LOWER LIMIT, FT 1/.................	1393.9						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.		93.70	94.30	97.10			
ASSUMED APR1-JUL31 INFLOW,KSFD 4/		3480.7	8688.8	8519.5			
MIN APR1-JUL31 OUTFLOW,KSFD		2441.8	2570.9	2796.7			
MICA REFILL REQUIREMENTS, KSFD 8/		1384.8	2830.0	2622.5			
MIN MAR31 RESERVOIR CONTENT,KSFD 5/		1155.9	291.6	479.0			
MIN MAR31 RESERVOIR CONTENT,FEET 6/		1402.8	1384.8	1389.0			
MAR31 ECC,FT. 7/------------------>		1402.8	1384.8	1389.0			
BASE ECC, FT.......................	1406.7						
LOWER LIMIT, FT 1/.................	1379.5						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.		85.50	87.60	90.20	91.20		
ASSUMED MAY1-JUL31 INFLOW,KSFD 4/		3176.1	8071.5	7914.1	3598.2		
MIN MAY1-JUL31 OUTFLOW,KSFD		2118.4	2220.3	2398.5	3379.0		
MICA REFILL REQUIREMENTS, KSFD 8/		1001.7	3039.3	3039.3	1160.2		
MIN APR30 RESERVOIR CONTENT,KSFD 5/		1520.3	769.2	1103.3	2200.2		
MIN APR30 RESERVOIR CONTENT,FEET 6/		1409.7	1395.1	1401.8	1421.7		
APR30 ECC,FT. 7/------------------>		1409.7	1395.1	1401.8	1410.5		
BASE ECC, FT.......................	1410.6						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.		61.20	66.50	68.50	65.30	71.60	
ASSUMED JUN1-JUL31 INFLOW,KSFD 4/		2273.4	6127.5	6010.2	2576.3	2610.5	
MIN JUN1-JUL31 OUTFLOW,KSFD		1587.1	1654.2	1771.7	2418.0	2418.0	
MICA REFILL REQUIREMENTS, KSFD 8/		674.8	2802.0	2797.8	800.6	800.6	
MIN MAY31 RESERVOIR CONTENT,KSFD 5/		2218.5	1908.5	2138.9	2620.7	2586.5	
MIN MAY31 RESERVOIR CONTENT,FEET 6/		1422.1	1416.7	1420.7	1428.8	1428.2	
MAY31 ECC,FT. 7/------------------>		1422.1	1416.7	1420.7	1426.4	1426.4	
BASE ECC, FT.......................	1426.3						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.		25.70	30.20	31.10	27.40	30.00	41.90
ASSUMED JUL1-JUL31 INFLOW,KSFD 4/		954.7	2782.6	2728.7	1081.0	1093.8	870.7
MIN JUL1-JUL31 OUTFLOW,KSFD		894.7	942.6	1026.5	1488.0	1488.0	1488.0
MICA REFILL REQUIREMENTS, KSFD 8/		358.5	1366.2	1365.4	452.6	452.6	452.6
MIN JUN30 RESERVOIR CONTENT,KSFD 5/		3161.1	3105.7	3242.8	3533.6	3520.8	3579.6
MIN JUN30 RESERVOIR CONTENT,FEET 6/		1437.5	1436.7	1438.8	1443.3	1443.1	1444.0
JUN30 ECC,FT. 7/------------------>		1437.5	1436.7	1438.8	1443.3	1443.1	1443.6
BASE ECC, FT.......................	1443.6						
JUL 31 ECC, FT..................		1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

1/ FOR ARROW AND DUNCAN: THE LOWER LIMIT WILL BE THE HIGHER OF THE ELEVATION NEEDED TO PROTECT AGAINST A RECURRENCE OF 1936-37 STREAMFLOWS OF THE PREVIOUS MONTH (V)ECC LESS THE QUANTITY ONE FOOT TINES THE NUMBER OF DAYS IN THE CURRENT MONTH. FOR MICA: THE LOWER LIMIT WILL BE THE ELEVATION NEEDED TO PROTECT AGAINST A RECURRENCE OF 1936-37 STREAMFLOWS.....2/ LINE 1 MINUS LINE 2.....3/ LINE 3 MINUS LINE 4.....4/ PRECEDING LINE X LINE 5.....5/ FOR ARROW LOCAL: FULL CONTENT (3579.6 KSFD) LESS LINE PRECEDING PLUS LINE PRECEDING THAT LESS LINE PRECEDING THAT. FOR ARROW TOTAL: FULL CONTENT (3579.6 KSFD) PLUS TWO PRECEDING LINES LESS LINE PRECEDING THAT.....6/ FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE. DATED FEB 21, 1973.
7/ LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR.
8/ FOR ARROW LOCAL: MICA MINIMUM POWER DISCHARGES. FOR ARROW TOTAL: MICA FULL CONTENT LESS ENERGY CONTENT CURVE.

TABLE 4
Variable Refill Curve
Duncan Reservoir

	INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN1-31JULY INFLOW,KAF		1639.7	1748.3	1693.7	1589.7	1505.6	1505.6
& IN KSFD		826.7	881.7	853.9	801.5	759.1	2759.1
95% FORECAST ERROR FOR DATE,IN KSFD		714.3	97.84	93.4	91.9	84.8	84.85
95% CONF.DATE-31JULY INFLOW,KSFD 2/		714.3	783.9	760.5	709.6	674.3	674.3
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.		100.00					
ASSUMED FEB1-JUL31 INFLOW,KSFD 4/		714.3					
MIN FEB1-JUL31 OUTFLOW,KSFD		108.8					
MIN JAN31 RESERVOIR CONTENT,KSFD 5/		100.3					
MIN JAN31 RESERVOIR CONTENT,FEET 6/		1813.7					
JAN31 ECC,FT. 7/------------------>		1821.3					
BASE ECC, FT........................	1833.6						
LOWER LIMIT, FT 1/..................	1821.3						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.		97.90	97.90				
ASSUMED MAR1-JUL31 INFLOW,KSFD 4/		699.3	767.4				
MIN MAR1-JUL31 OUTFLOW,KSFD		106.0	114.4				
MIN FEB28 RESERVOIR CONTENT,KSFD 5/		112.5	52.8				
MIN FEB28 RESERVOIR CONTENT,FEET 6/		1815.7	1805.4				
FEB28 ECC,FT. 7/------------------>		1815.7	1805.4				
BASE ECC, FT........................	1834.9						
LOWER LIMIT, FT 1/..................	1807.7						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.		95.40	95.40	97.50			
ASSUMED APR1-JUL31 INFLOW,KSFD 4/		681.4	747.9	741.5			
MIN APR1-JUL31 OUTFLOW,KSFD		102.9	111.3	126.1			
MIN MAR31 RESERVOIR CONTENT,KSFD 5/		127.2	69.3	90.4			
MIN MAR31 RESERVOIR CONTENT,FEET 6/		1818.1	1808.4	1812.1			
MAR31 ECC,FT. 7/------------------>		1818.1	1808.4	1812.1			
BASE ECC, FT........................	1836.9						
LOWER LIMIT, FT 1/..................	1802.5						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.		89.50	89.50	91.50	93.80		
ASSUMED MAY1-JUL31 INFLOW,KSFD 4/		639.5	701.6	695.9	665.6		
MIN MAY1-JUL31 OUTFLOW,KSFD		83.5	89.4	99.7	156.4		
MIN APR30 RESERVOIR CONTENT,KSFD 5/		150.0	93.6	109.6	196.6		
MIN APR30 RESERVOIR CONTENT,FEET 6/		1821.6	1812.6	1815.2	1828.5		
APR30 ECC,FT. 7/------------------>		1821.6	1812.6	1815.2	1828.5		
BASE ECC, FT........................	1833.6						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.		68.60	68.60	70.20	71.90	76.70	
ASSUMED JUN1-JUL31 INFLOW,KSFD 4/		490.0	537.8	533.9	510.2	517.2	
MIN JUN1-JUL31 OUTFLOW,KSFD		55.4	59.3	66.1	103.7	103.7	
MIN MAY31 RESERVOIR CONTENT,KSFD 5/		271.2	227.3	238.0	299.3	292.3	
MIN MAY31 RESERVOIR CONTENT,FEET 6/		1839.0	1832.9	1834.4	1842.8	1841.8	
MAY31 ECC,FT. 7/------------------>		1839.0	1832.9	1834.4	1842.8	1841.8	
BASE ECC, FT........................	1848.4						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.		32.20	32.20	37.90	33.70	35.90	46.80
ASSUMED JUL1-JUL31 INFLOW,KSFD 4/		230.0	252.4	249.4	239.1	242.1	225.2
MIN JUL1-JUL31 OUTFLOW,KSFD		28.1	30.1	33.6	52.7	52.7	52.7
MIN JUN30 RESERVOIR CONTENT,KSFD 5/		503.9	483.5	490.0	519.4	516.4	531.6
MIN JUN30 RESERVOIR CONTENT,FEET 6/		1868.6	1866.1	1866.9	1870.4	1870.1	1871.9
JUN30 ECC,FT. 7/------------------>		1868.6	1866.1	1866.9	1870.4	1870.1	1871.9
BASE ECC, FT........................	1871.9						
JUL 31 ECC, FT..................		1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

1/ FOR ARROW AND DUNCAN: THE LOWER LIMIT WILL BE THE HIGHER OF THE ELEVATION NEEDED TO PROTECT AGAINST A RECURRENCE OF 1936-37 STREAMFLOWS OF THE PREVIOUS MONTH (V)ECC LESS THE QUANTITY ONE FOOT TINES THE NUMBER OF DAYS IN THE CURRENT MONTH. FOR MICA: THE LOWER LIMIT WILL BE THE ELEVATION NEEDED TO PROTECT AGAINST A RECURRENCE OF 1936-37 STREAMFLOWS.
2/ LINE 1 MINUS LINE 2.....3/ LINE 3 MINUS LINE 4.....4/ PRECEDING LINE X LINE 5
5/ FULL CONTENT (705.8 KSFD) PLUS LINE PRECEDING THAT LESS LINE PRECEDING THAT.
6/ FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE. DATED FEB 21, 1973.
7/ LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR.

TABLE 5
Variable Refill Curve
Libby Reservoir

	INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN1-31JULY INFLOW,KAF		6090.0	6130.1	5737.1	5123.4	5452.6	5481.9
& IN KSFD		3070.4	3090.6	2892.5	2583.0	2749.0	2763.8
95% FORECAST ERROR FOR DATE, IN KSFD		886.8	606.4	552.5	533.4	474.5	367.5
OBSERVED JAN1-DATE INFLOW, IN KSFD		0.0	91.3	178.0	304.2	557.4	1284.1
95% CONF.DATE-31JULY INFLOW,KSFD 1/		2183.6	2392.9	2161.9	1745.4	1717.1	1112.2
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.		97.14					
ASSUMED FEB1-JUL31 INFLOW,KSFD 2/		2121.1					
FEB MINIMUM FLOW REQUIREMENT,CFS 3/		4000.0					
MIN FEB1-JUL31 OUTFLOW,KSFD 4/		724.0					
MIN JAN31 RESERVOIR CONTENT,KSFD 5/		1113.4					
MIN JAN31 RESERVOIR CONTENT,FEET 6/		2387.3					
JAN31 ECC,FT. 7/------------------>		2387.3					
BASE ECC, FT......................	2417.8						
LOWER LIMIT, FT....................	2287.7						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.		94.47	97.25				
ASSUMED MAR1-JUL31 INFLOW,KSFD 2/		2062.8	2327.1				
MAR MINIMUM FLOW REQUIREMENT,CFS 3/		4000.0	4000.0				
MIN MAR1-JUL31 OUTFLOW,KSFD 4/		612.0	612.0				
MIN FEB28 RESERVOIR CONTENT,KSFD 5/		1059.7	795.4				
MIN FEB28 RESERVOIR CONTENT,FEET 6/		2383.6	2364.4				
FEB28 ECC,FT. 7/------------------>		2383.6	2364.4				
BASE ECC, FT......................	2415.0						
LOWER LIMIT, FT....................	2287.0						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.		91.24	93.92	96.58			
ASSUMED APR1-JUL31 INFLOW,KSFD 2/		1992.3	2247.4	2088.0			
APR MINIMUM FLOW REQUIREMENT,CFS 3/		4000.0	4000.0	4000.0			
MIN APR1-JUL31 OUTFLOW,KSFD 4/		488.0	488.0	488.0			
MIN MAR31 RESERVOIR CONTENT,KSFD 5/		1006.2	751.1	910.5			
MIN MAR31 RESERVOIR CONTENT,FEET 6/		2380.0	2361.0	2373.1			
MAR31 ECC,FT. 7/------------------>		2380.0	2361.0	2373.1			
BASE ECC, FT......................	2412.2						
LOWER LIMIT, FT....................	2287.0						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.		83.21	85.65	88.08	91.20		
ASSUMED MAY1-JUL31 INFLOW,KSFD 2/		1817.0	2049.5	1904.2	1591.8		
MAY MINIMUM FLOW REQUIREMENT,CFS 3/		4000.0	4000.0	4000.0	4000.0		
MIN MAY1-JUL31 OUTFLOW,KSFD 4/		368.0	368.0	368.0	368.0		
MIN APR30 RESERVOIR CONTENT,KSFD 5/		1061.5	829.0	974.3	1286.7		
MIN APR30 RESERVOIR CONTENT,FEET 6/		2383.8	2367.0	2377.7	2398.5		
APR30 ECC,FT. 7/------------------>		2383.8	2367.0	2377.7	2398.5		
BASE ECC, FT......................	2411.3						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.		56.86	57.50	59.13	61.22	67.13	
ASSUMED JUN1-JUL31 INFLOW,KSFD 2/		1241.6	1375.9	1278.3	1068.5	1152.7	
JUN MINIMUM FLOW REQUIREMENT,CFS 3/		4000.0	4000.0	4000.0	4000.0	4000.0	
MIN JUN1-JUL31 OUTFLOW,KSFD 4/		244.0	244.0	244.0	244.0	244.0	
MIN MAY31 RESERVOIR CONTENT,KSFD 5/		1512.9	1378.6	1476.2	1685.9	1601.8	
MIN MAY31 RESERVOIR CONTENT,FEET 6/		2411.6	2403.9	2409.6	2420.7	2416.3	
MAY31 ECC,FT. 7/------------------>		2411.6	2403.9	2409.6	2420.7	2416.3	
BASE ECC, FT......................	2434.4						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.		19.41	19.98	20.54	21.27	23.32	34.74
ASSUMED JUL1-JUL31 INFLOW,KSFD 2/		423.8	478.1	444.1	371.3	400.4	386.4
JUL MINIMUM FLOW REQUIREMENT,CFS 3/		4000.0	4000.0	4000.0	4000.0	4000.0	4000.0
MIN JUL1-JUL31 OUTFLOW,KSFD 4/		124.0	124.0	124.0	124.0	124.0	124.0
MIN JUN30 RESERVOIR CONTENT,KSFD 5/		2210.7	2156.4	2190.4	2263.2	2234.1	2248.1
MIN JUN30 RESERVOIR CONTENT,FEET 6/		2445.8	2443.3	2444.9	2448.2	2446.9	2447.5
JUN30 ECC,FT. 7/------------------>		2445.8	2443.3	2444.9	2448.2	2446.9	2447.5
BASE ECC, FT......................	2456.6						
JUL 31 ECC, FT..................		2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF 8/		89.9	89.1	87.7	73.1	73.1	69.1

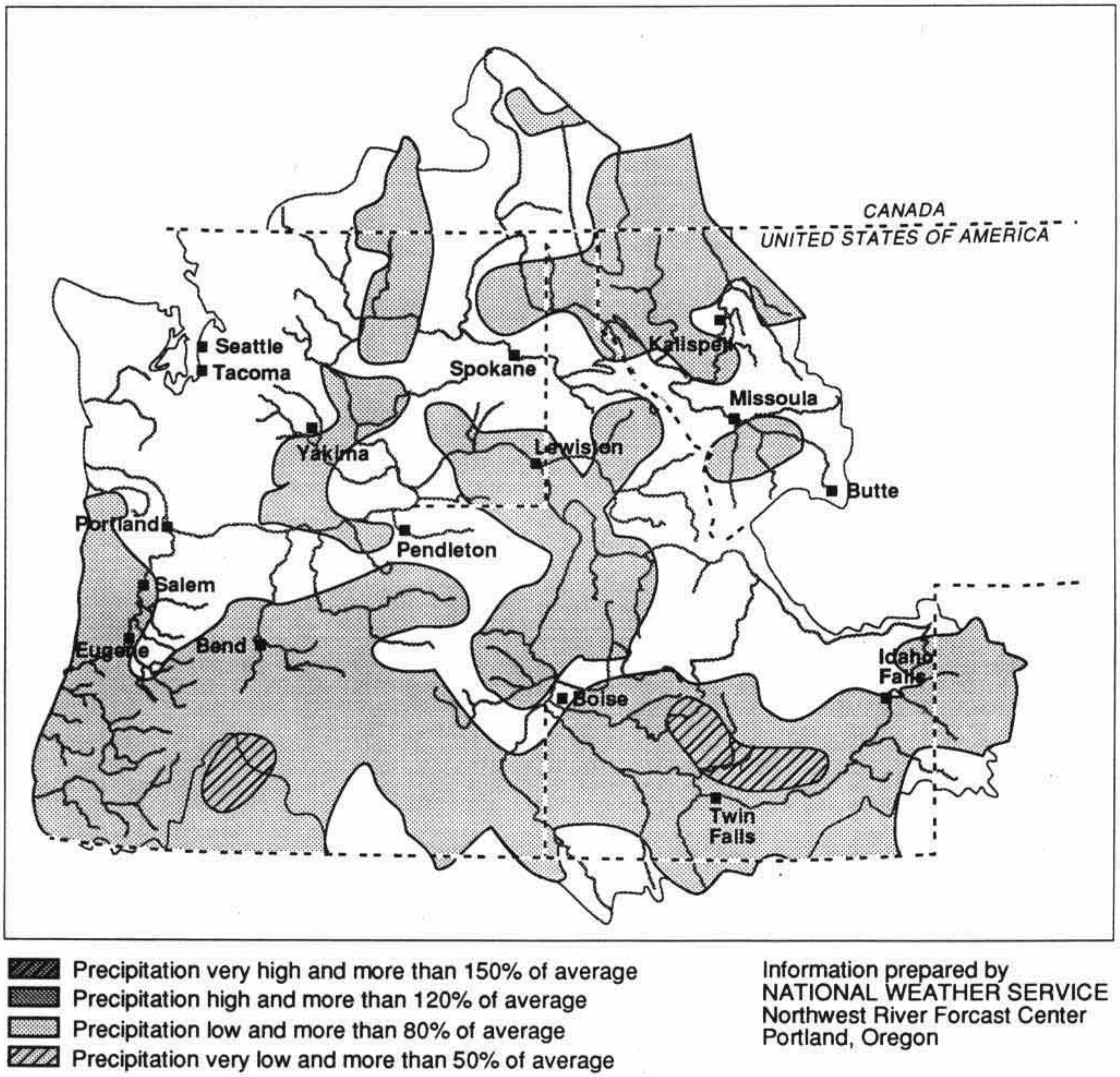
1/ EXPECTED INFLOW MINUS (95%ERROR & JAN1-DATE INFLOW)................ 2/ PRECEDING LINE TIMES LINE 1/
3/ BASED ON POWER DISCHARGE REQUIREMENTS, DETERMINED FROM 8/.....4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/, FROM DATE TO JULY
5/ FULL CONTENT (2510.5 KSFD), PLUS 4/, AND MINUS 2/......6/ ELEV. FROM 5/, INTERP. FROM NWPP STORAGE CONTENT TABLE
7/ ELEV. FROM 6/, BUT LIMITED < BASE ECC, & > ECC LOWER LIMIT....8/ USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/

Table 6

Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 1992

1 May Forecast of May-August Unregulated Runoff Volume, MAF		49.4
Less Estimated Depletions, MAF		1.5
Less Upstream Storage Corrections, MAF		
MICA	6.3	
ARROW	2.9	
DUNCAN	1.3	
LIBBY	3.2	
LIBBY + DUNCAN UNDER DRAFT*	-0	
HUNGRY HORSE	1.2	
FLATHEAD LAKE	0.5	
NOXON	0.0	
PEND OREILLE LAKE	0.5	
GRAND COULEE	2.0	
BROWNLEE	0.0	
DWORSHAK	0.1	
JOHN DAY	0.2	
TOTAL	18.2	19.7
Forecast of Adjusted Residual Runoff Volume, MAF		29.7
Computed Initial Controlled Flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		200.0

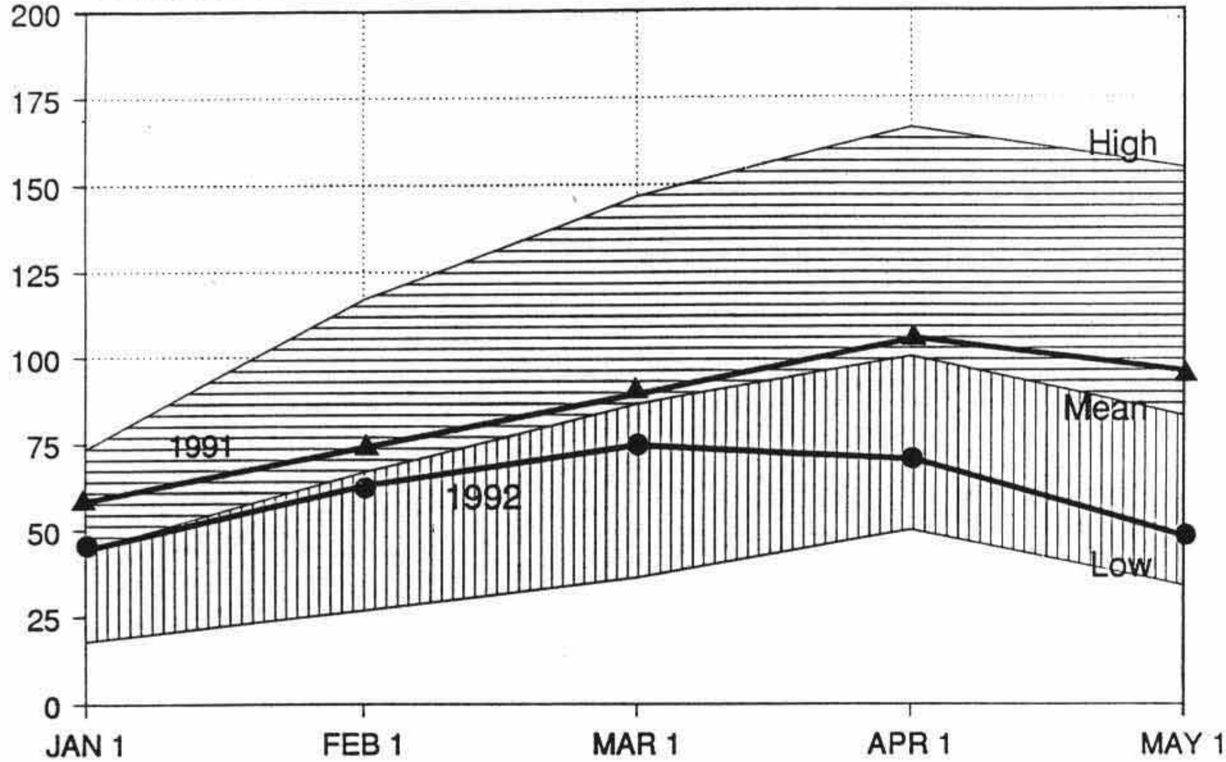
Chart 1
Seasonal Precipitation
Columbia River Basin
October 1991 - March 1992
Percent of 1961 -1990 Average

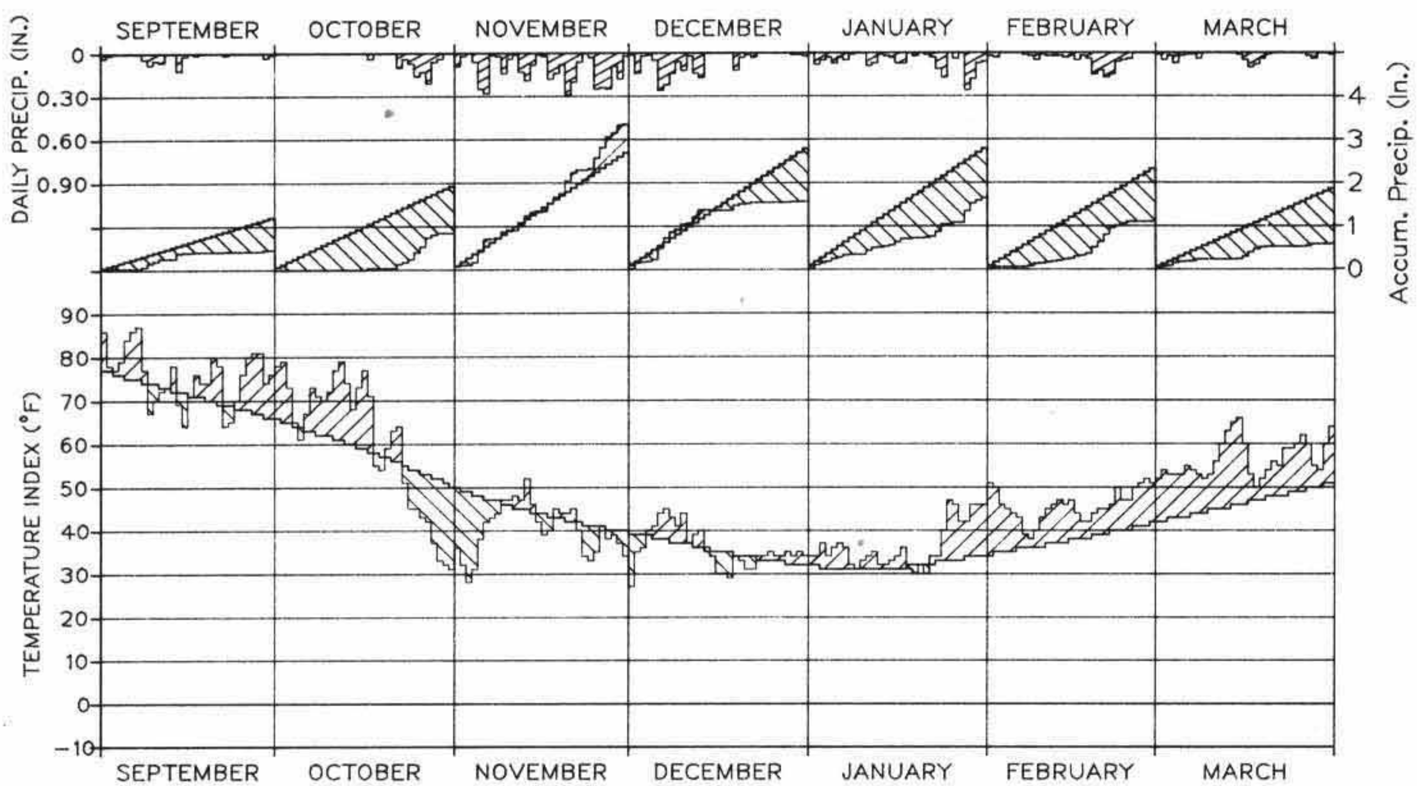


Information prepared by
NATIONAL WEATHER SERVICE
Northwest River Forcast Center
Portland, Oregon

Chart 2

Columbia Basin Snowpack

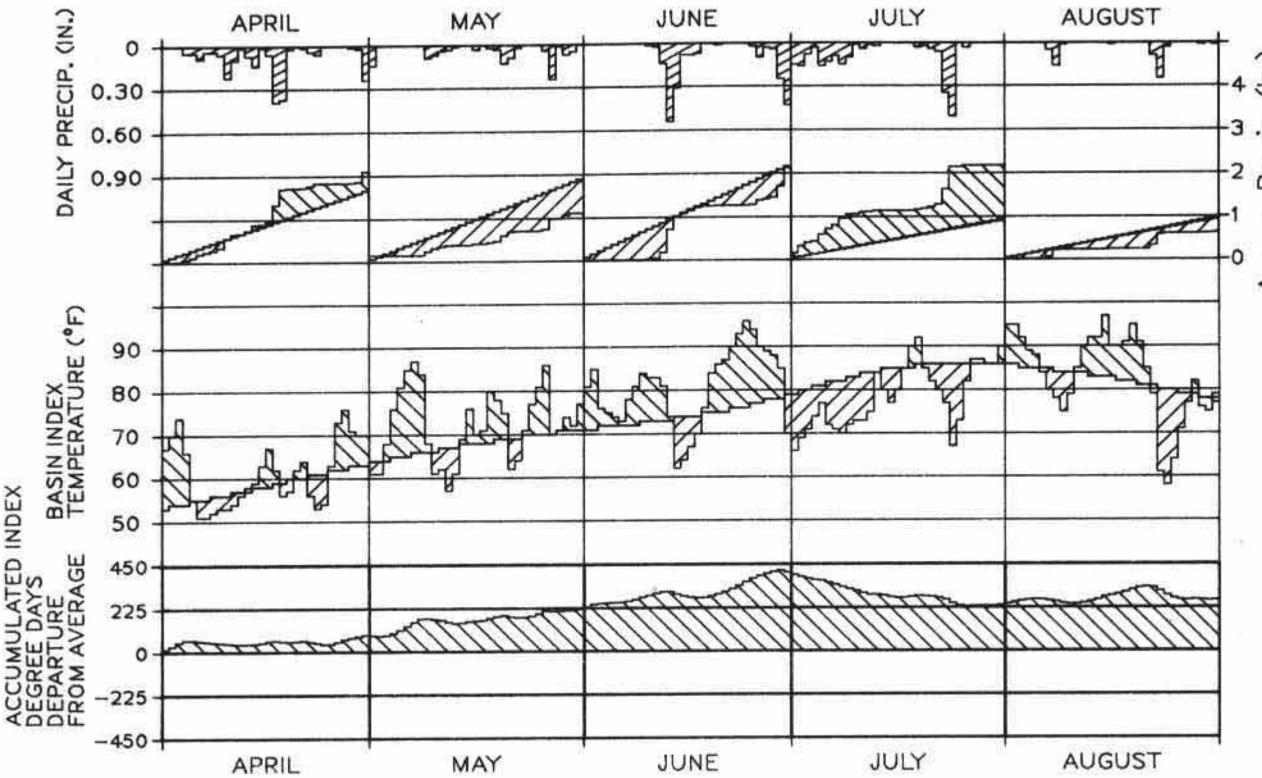




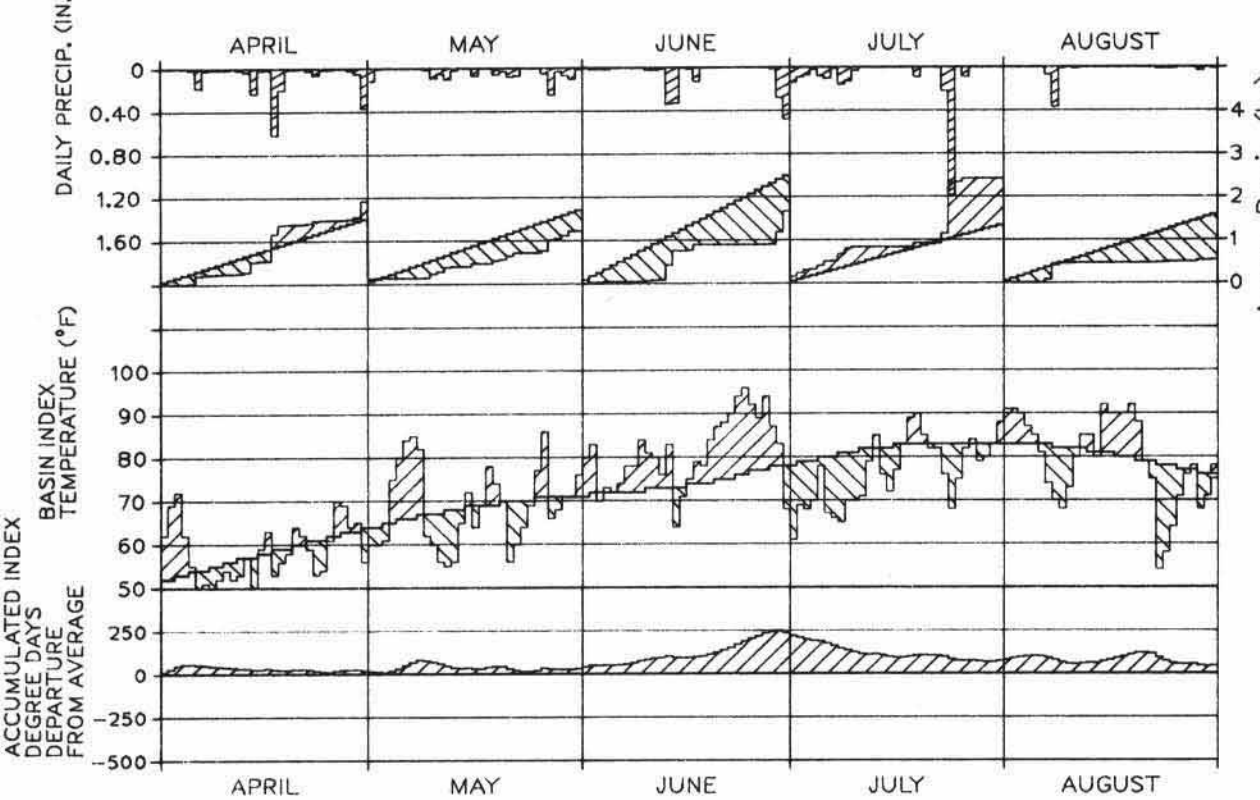
WINTER SEASON Chart 3

TEMPERATURE AND PRECIPITATION INDEX 1991–1992

Columbia River Basin Above The Dalles, OR

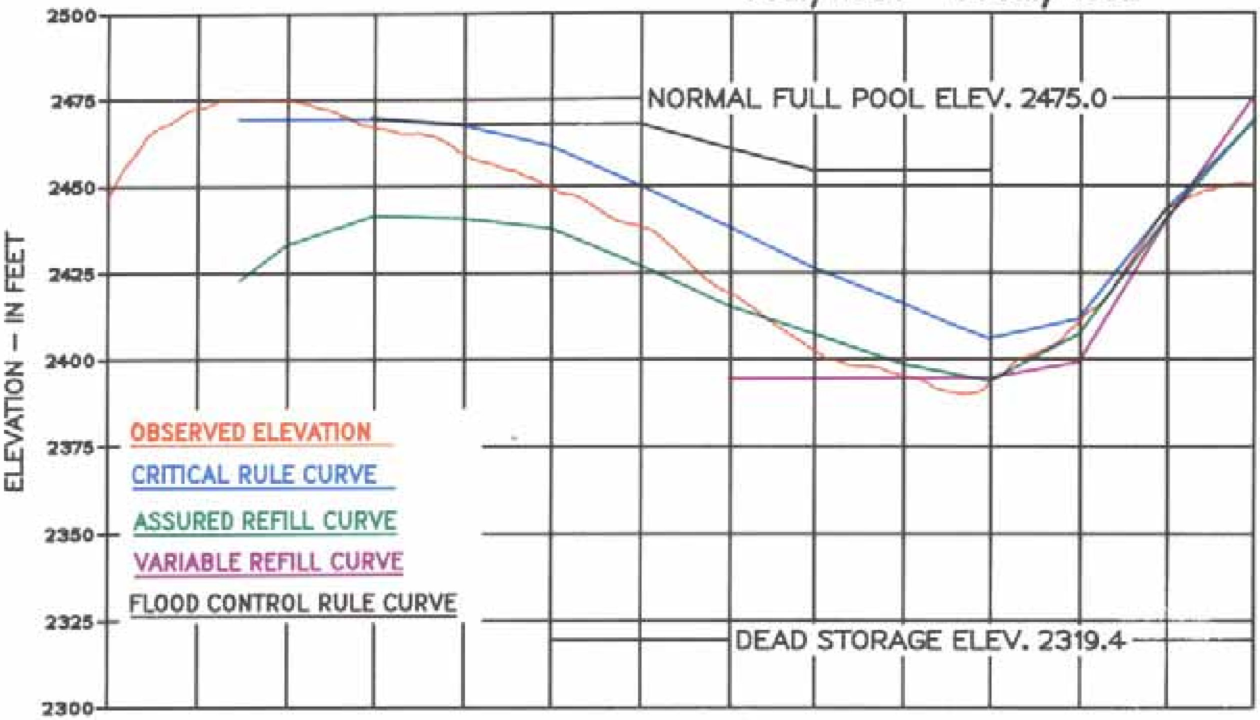


1992 SNOWMELT SEASON CHART 4
TEMPERATURE AND PRECIPITATION INDEX
Columbia River Basin Above The Dalles, OR



1992 SNOWMELT SEASON Chart 5
TEMPERATURE AND PRECIPITATION INDEX
Columbia River Basin In Canada

Chart 6
Regulation of Mica
1 July 1991 – 31 July 1992



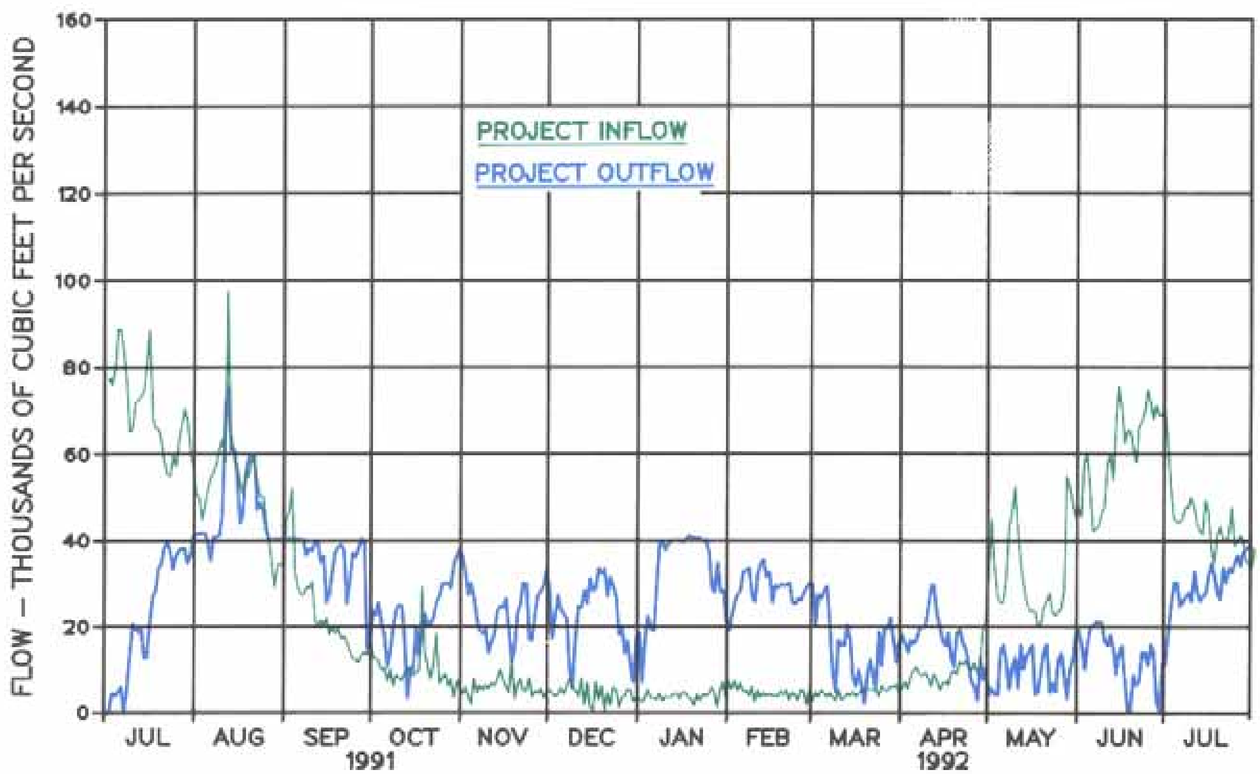
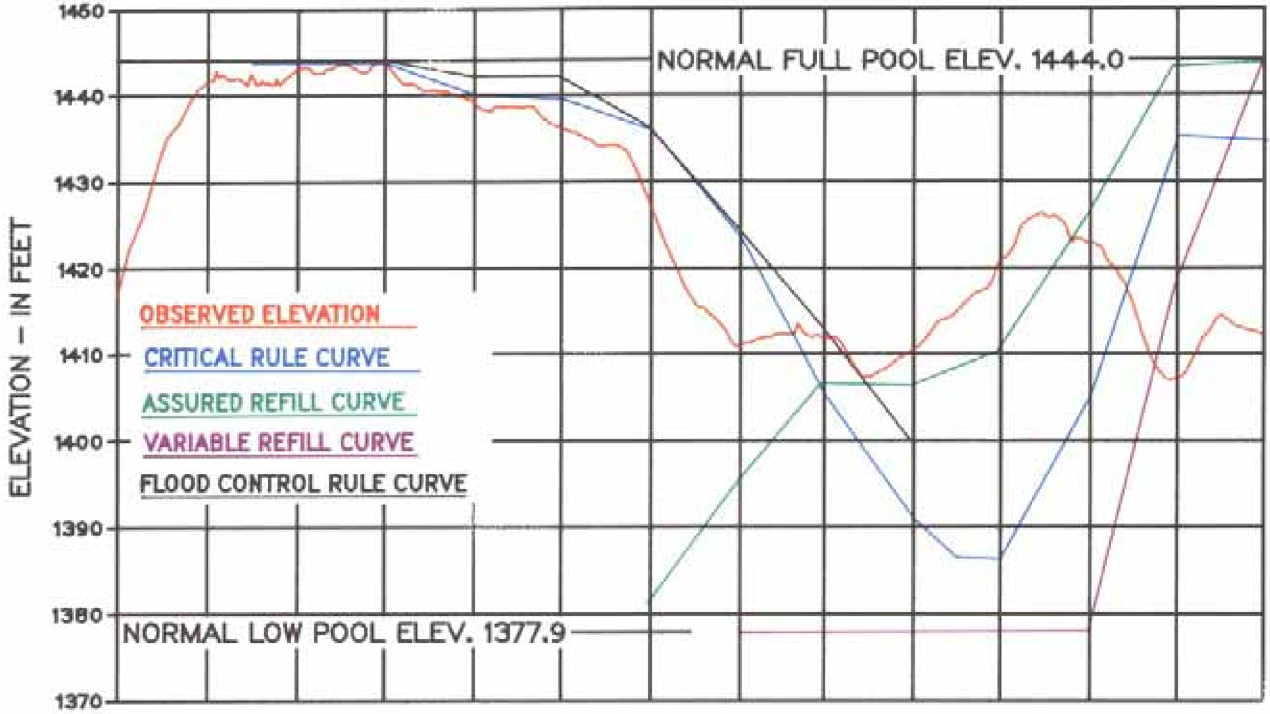


Chart 7
Regulation of Arrow
1 July 1991 – 31 July 1992



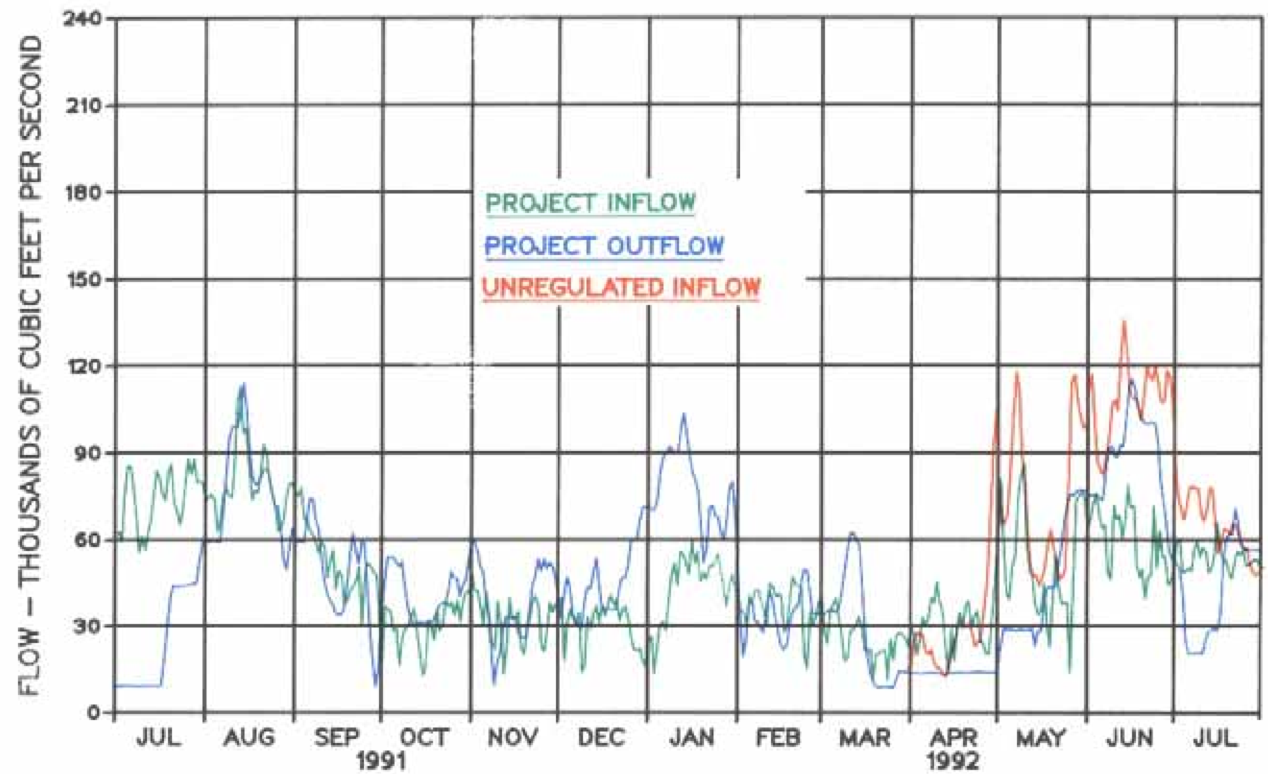
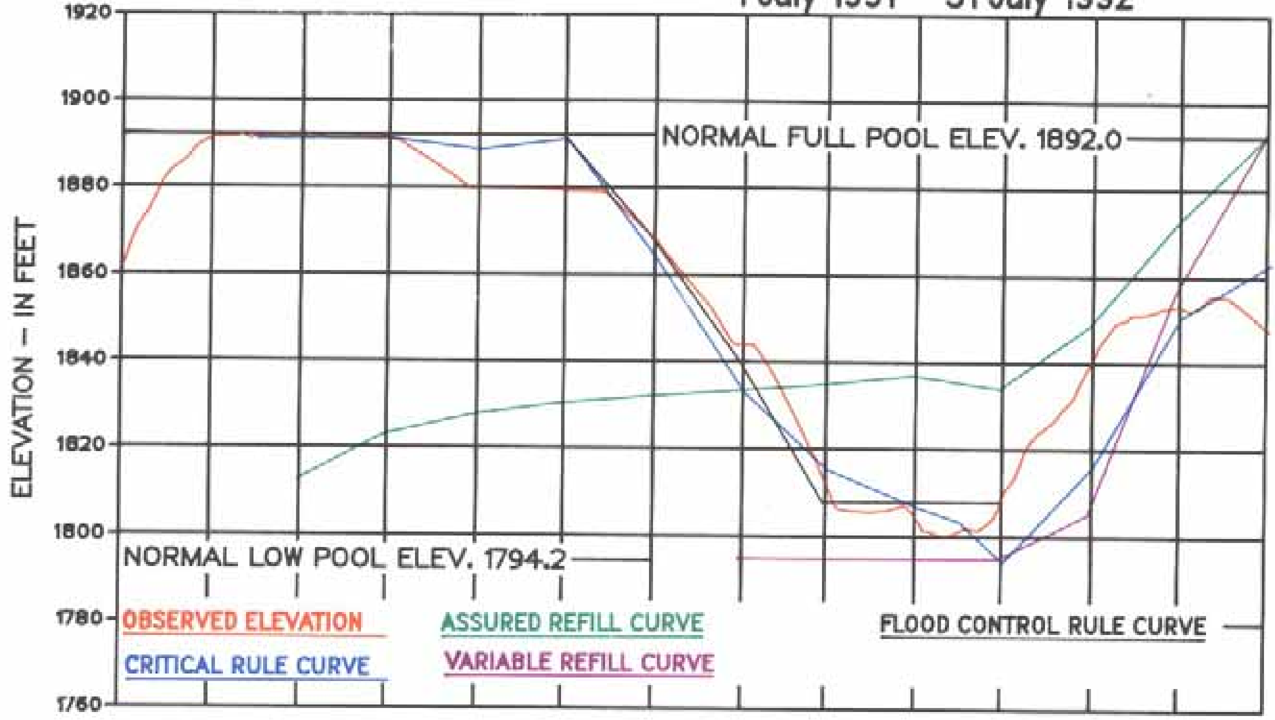


Chart 8
Regulation of Duncan
1 July 1991 – 31 July 1992



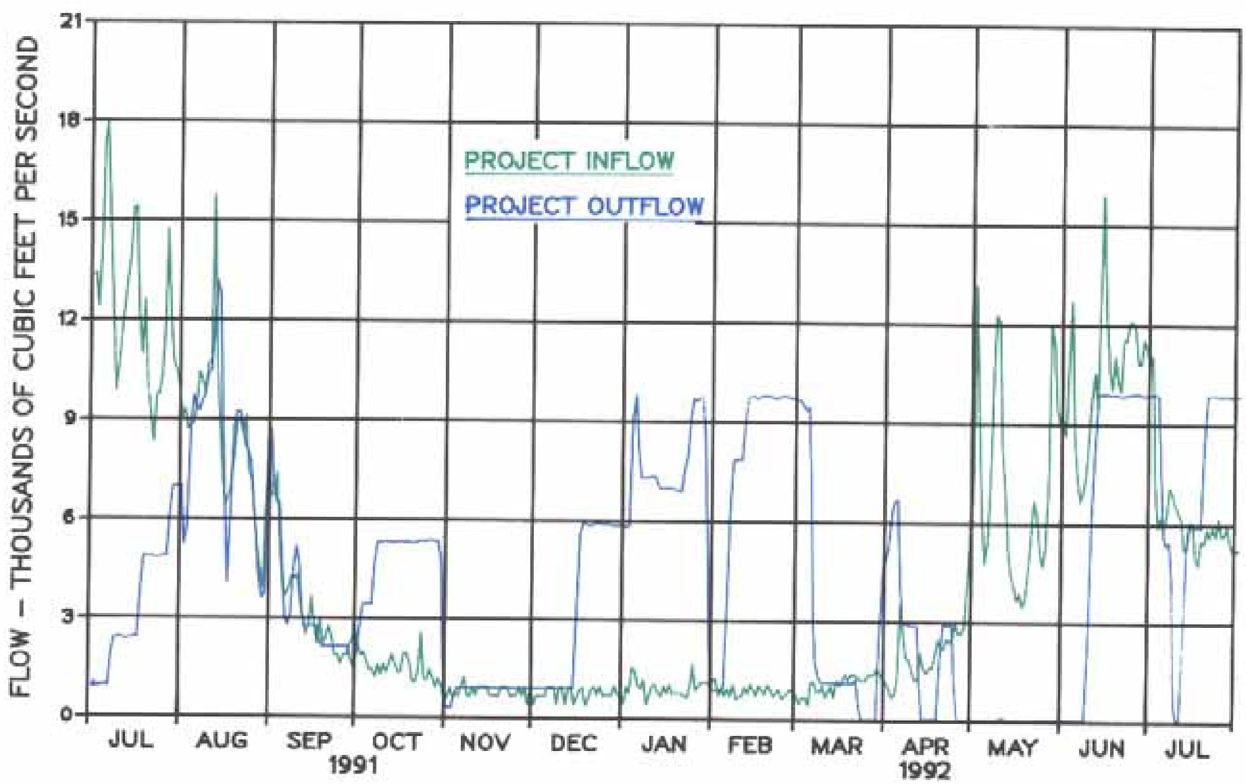
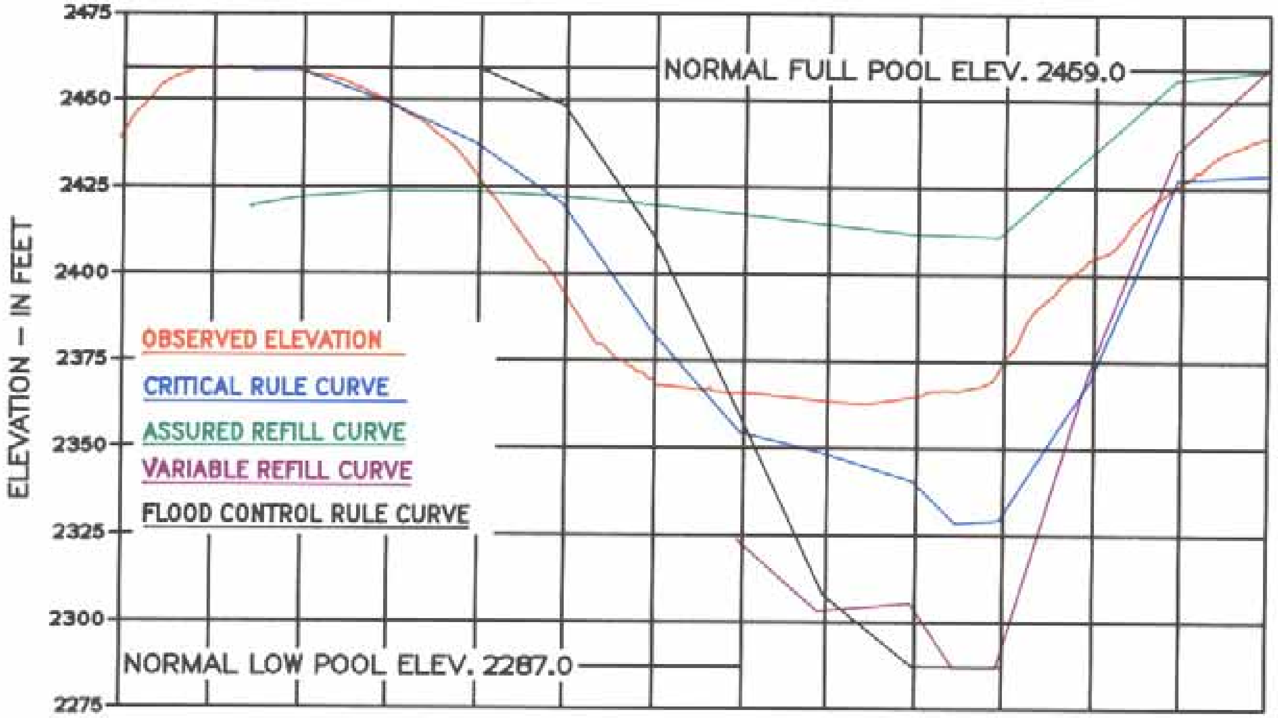


Chart 9
Regulation of Libby
1 July 1991-31 July 1992



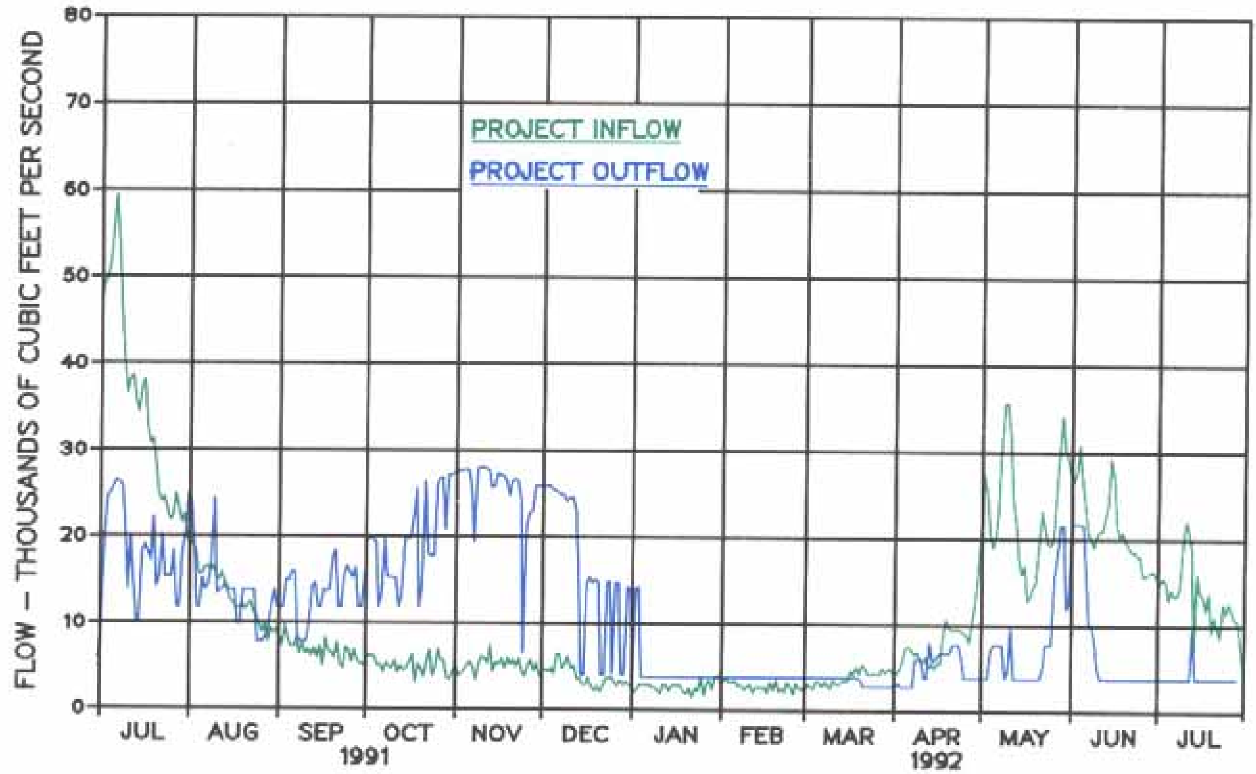


Chart 10
Regulation of Kootenay Lake
1 July 1991-31 July 1992

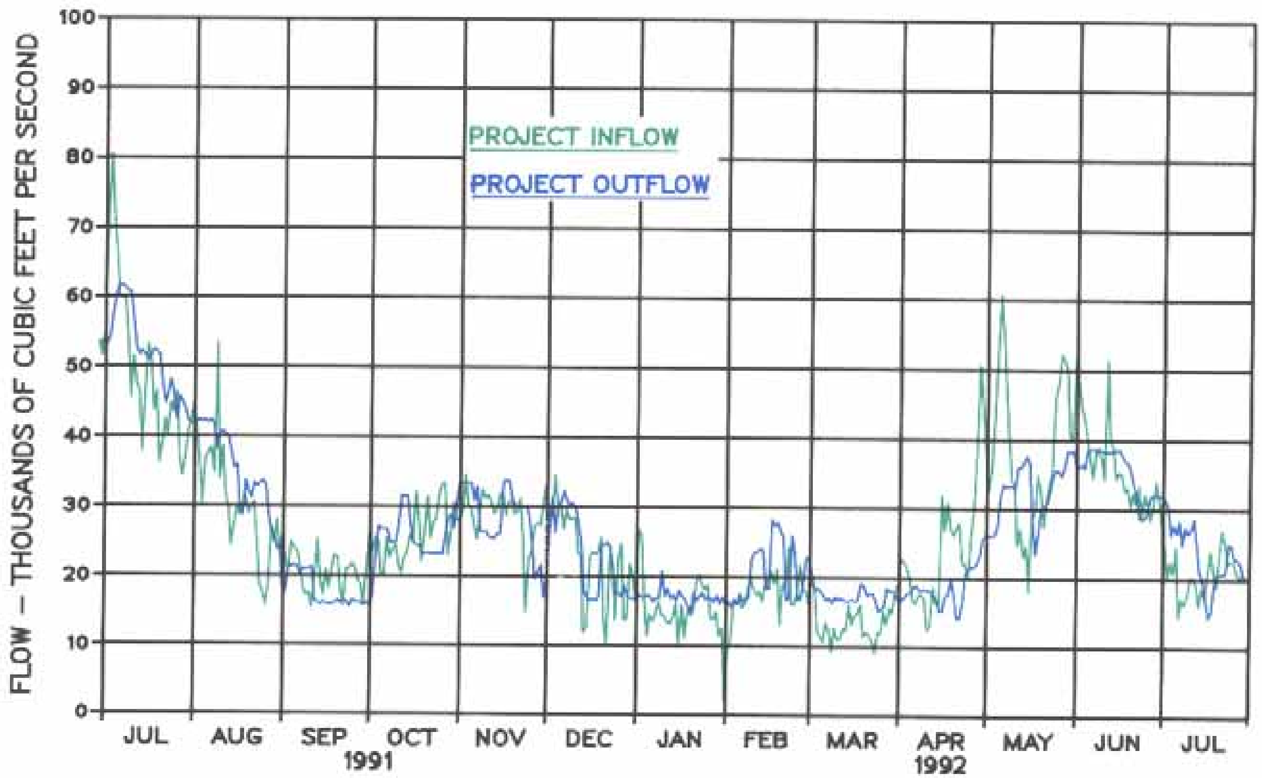


Chart 11
Columbia River at Birchbank
1 July 1991 – 31 July 1992

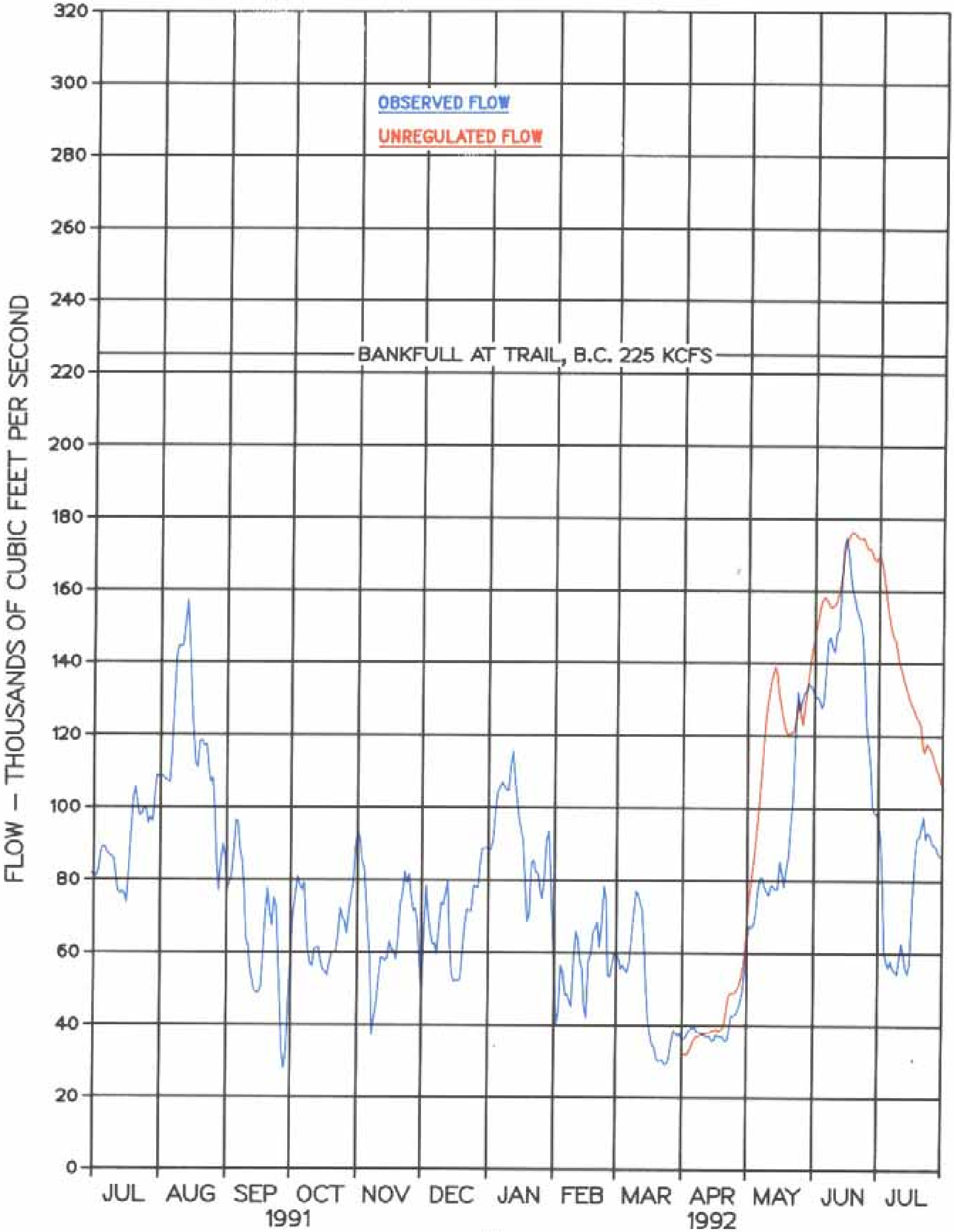
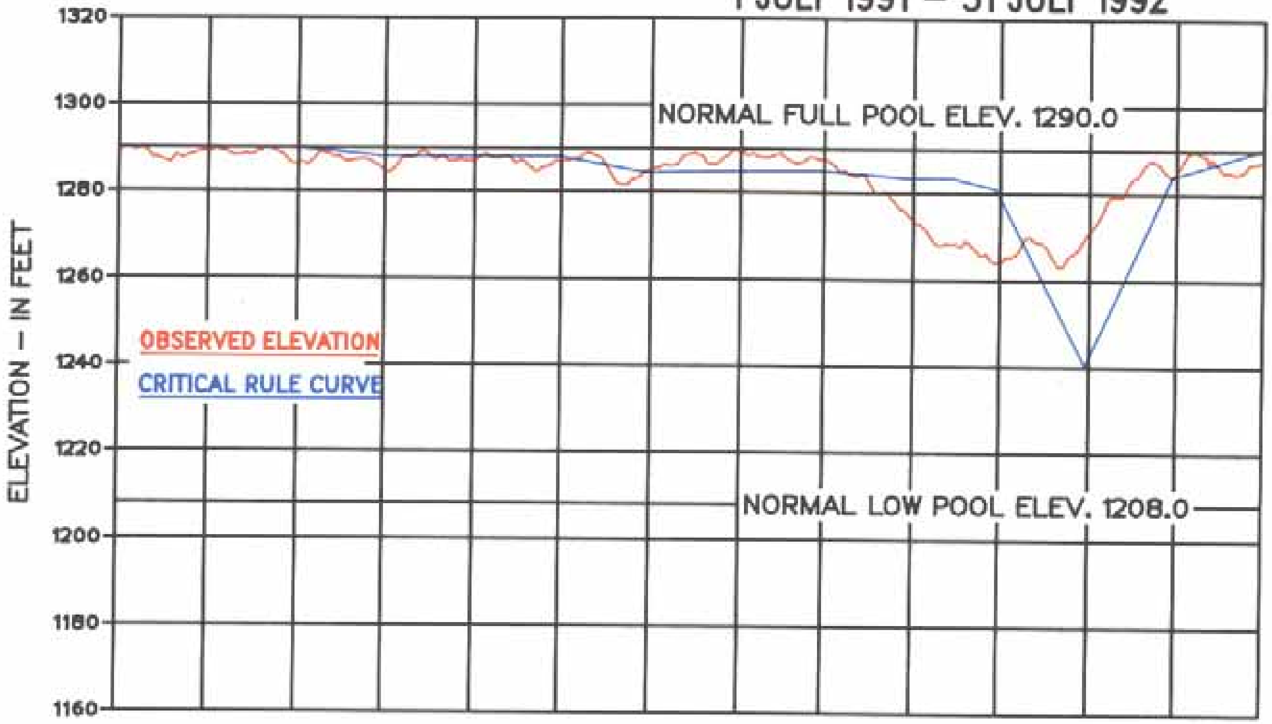


Chart 12
Regulation of Grand Coulee
1 JULY 1991 – 31 JULY 1992



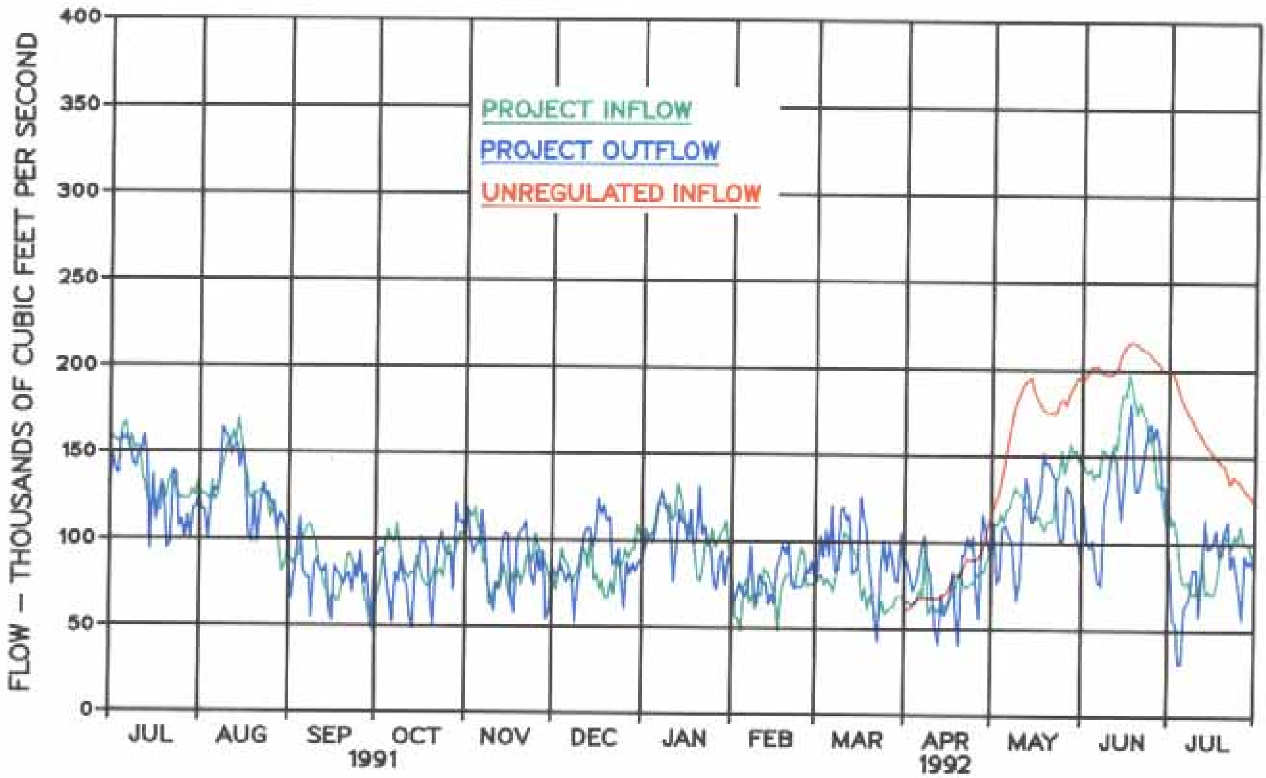


Chart 13
Columbia River at The Dalles
1 July 1991 - 31 July 1992

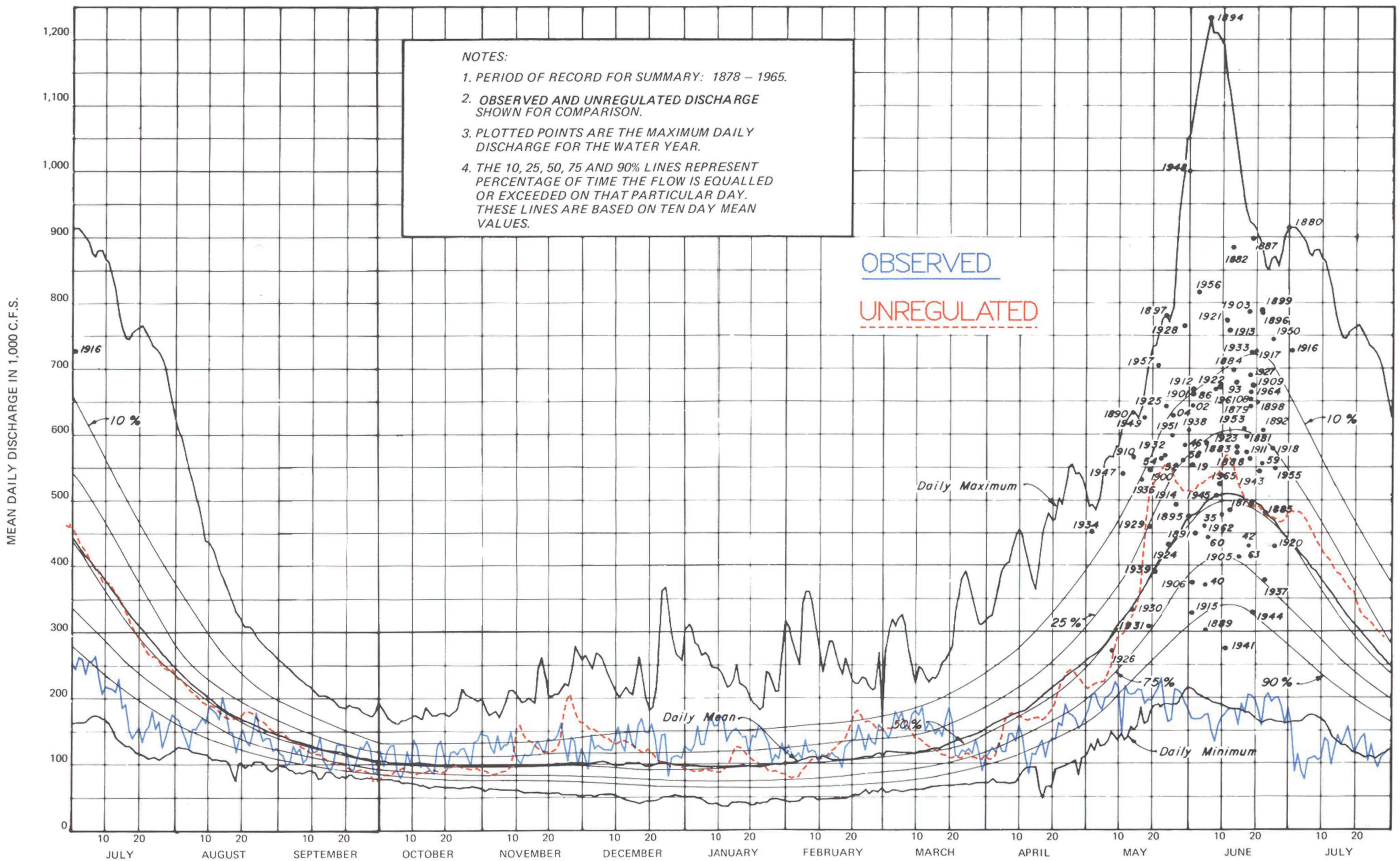


Chart 14
Columbia River at The Dalles
1 April 1992 – 31 July 1992

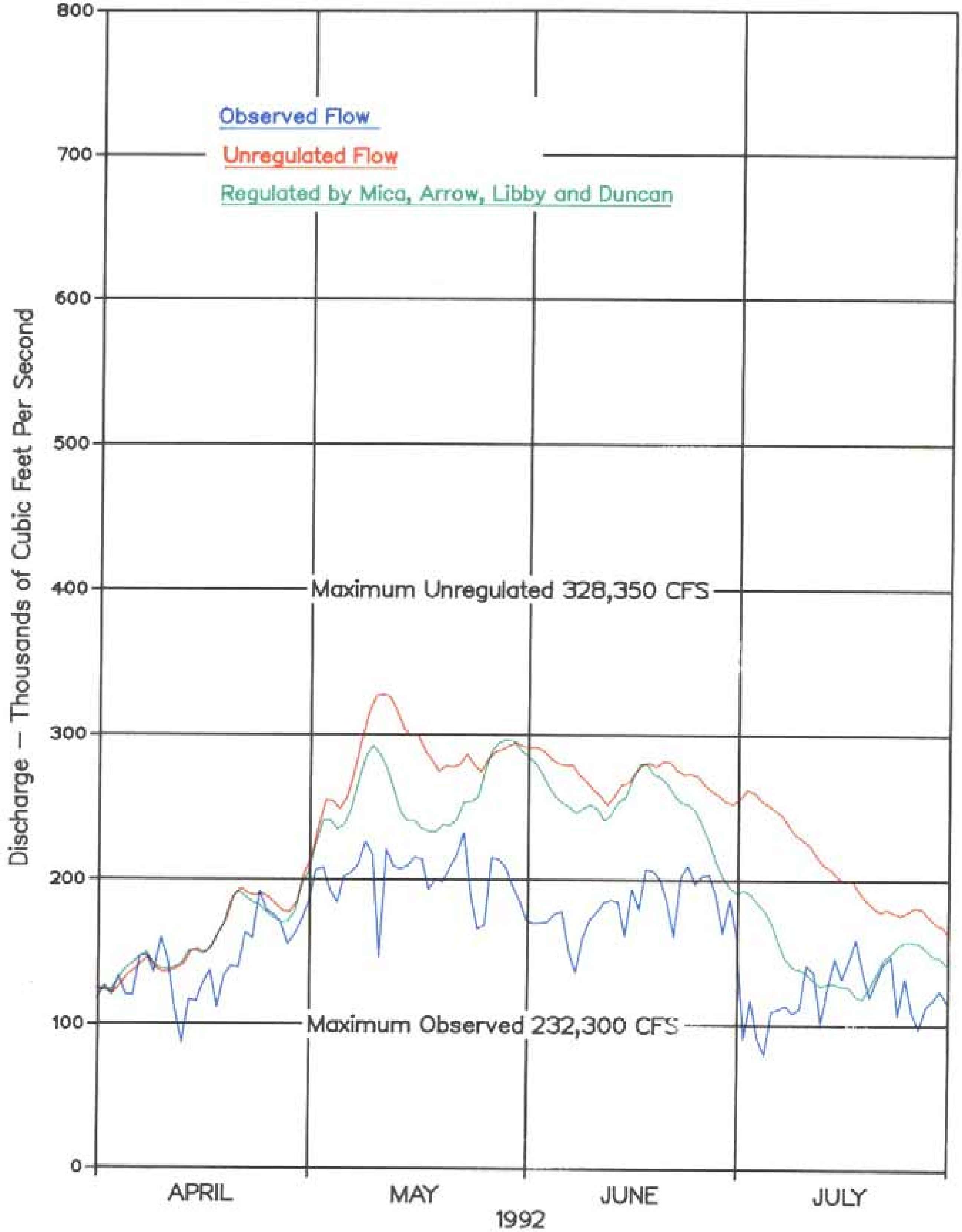


Chart 15
1992 Relative Filling
Arrow and Grand Coulee