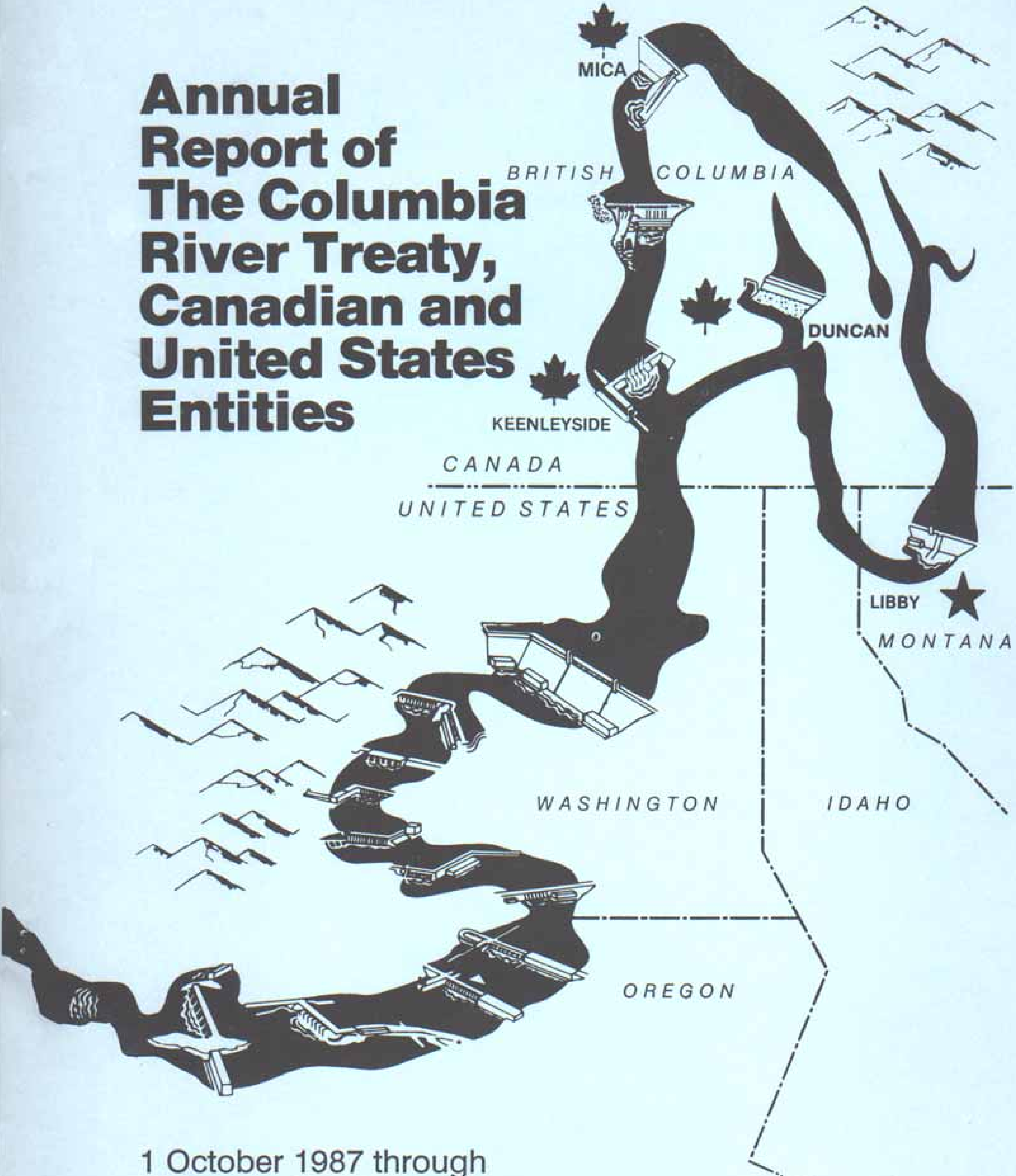
Annual Report of The Columbia River Treaty, Canadian and United States Entities



1 October 1987 through
30 September 1988

November 1988

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

FOR THE PERIOD
1 OCTOBER 1987 - 30 SEPTEMBER 1988

Executive Summary

Entity

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

- Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1987 through 31 July 1988, dated October 1987.
- Columbia River Treaty Entities Agreement to Study Several Outstanding Issues Concerning the Assured Operating Plan and Determination of Downstream Power Benefits.
- Columbia River Treaty Entity Agreement on Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies.
- Columbia River Treaty Entity Agreement on Changes to the Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies.

Subsequent to the period of this report the following Agreement was signed:

- Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefit studies for Operating Year 1992-93, dated September 1988.

System Operation

The coordinated system filled to about 98.5% of capacity on 31 July 1987. The system remained close to full through the summer although most of the reservoirs were 5-10 feet below full by 1 September. Fall was very dry with much below normal precipitation occurring in the September - November period. December precipitation for the Columbia Basin was near normal, as measured at The Dalles, resulting in a January water supply forecast for the January - July period of 79.2 maf, 72.9%. The actual observed runoff was 72.7 maf, 66.9%, and the peak daily average flow observed at The Dalles was 236,000 cfs. Daily flood control requests were not used this year. Refill of the coordinated system was seriously impaired by the low runoff. On 31 July was near 84% of capacity, requiring that the third-year firm energy load carrying capability be adopted for the 1988-89 operating year.

The generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange Agreement, was 393 average megawatts at rates up to 1,052 megawatts from August 1987 through 31 March 1988, and 368 average megawatts at rates up to 1,012 megawatts from

1 April 1988 through 31 July 1988. All CSPE power was used to meet Pacific Northwest loads during the period of this report.

Project Operation

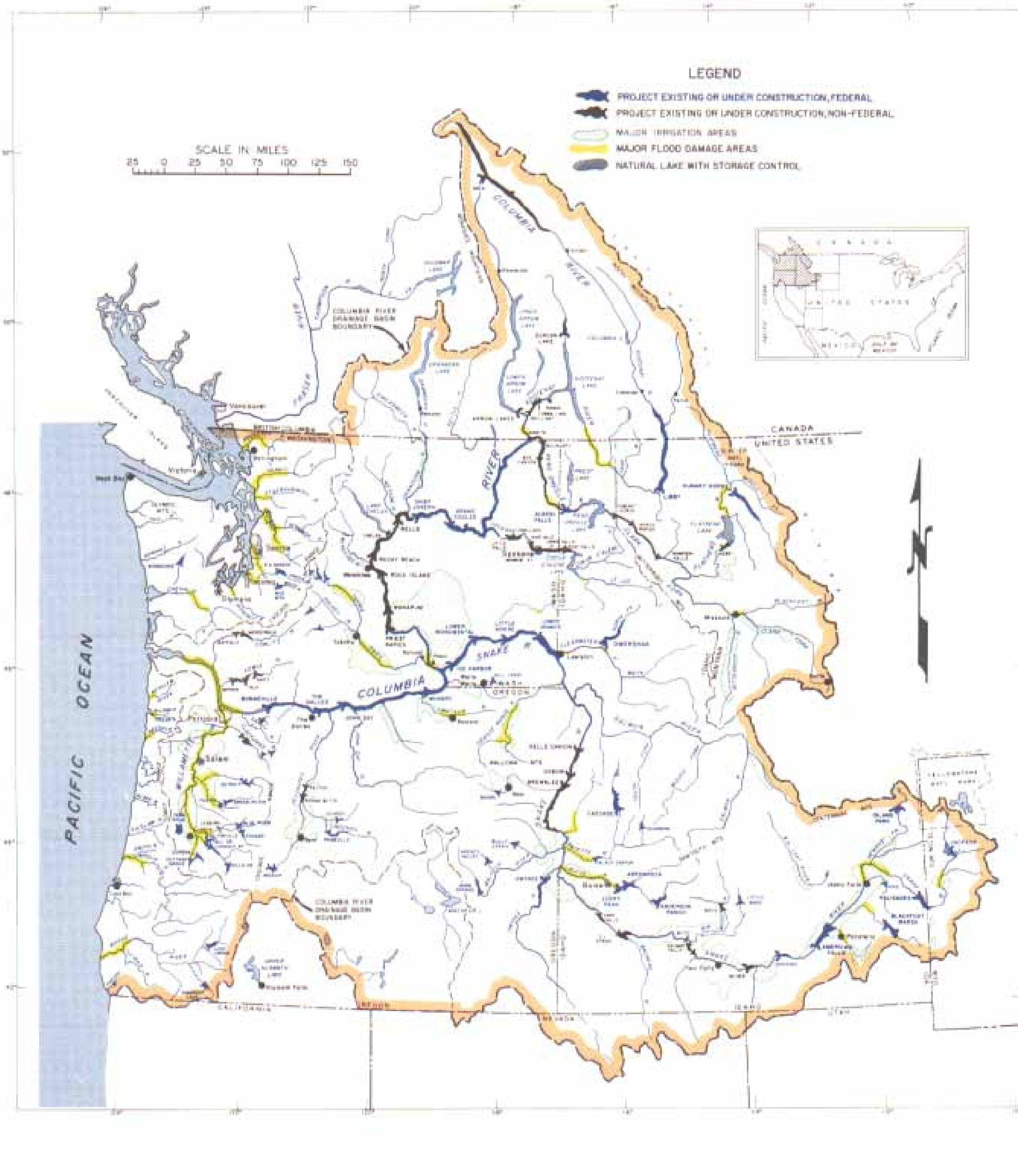
Mica Treaty storage was refilled on 14 July 1987. The reservoir was drafted to its minimum level, 2365.2 feet, by 15 April 1988. Treaty storage was refilled by 10 August 1988; however, the total reservoir storage did not fully refill as non-Treaty accounts were only partially filled. The actual reservoir level on 10 August was elevation 2443.2 feet.

Arrow Reservoir started the period about four feet below full, however, some of the Treaty storage was in Revelstoke. The project was drafted to elevation 1385.5 feet by 21 February 1988, the lowest level of the operating year. The reservoir filled through the spring reaching elevation 1439.2 feet by 31 July. The adjusted reservoir elevation was about three feet below this level at elevation 1436.5 feet as some BC Hydro non-Treaty storage had been transferred from Mica to Arrow. During the summer additional water was transferred from Mica to Arrow to hold Arrow up for recreation as low flows were causing the coordinated system to draft to meet power loads.

Duncan Reservoir was at full pool elevation 1892.0 feet at the beginning of the period and reached its lowest level, elevation 1794.2, feet on 26 February 1988. The reservoir refilled to elevation 1892.0 on 26 July. Draft began on 10 August reaching a level of 1881.8 feet on 31 August.

Libby Reservoir started the period near elevation 2454 feet and remained in the top five feet through Labor Day. The reservoir reached its lowest level 2317.4 feet on 26 March 1988. Inflows to Libby for the September - March period were the sixth lowest in the 1926-88 period of record. The observed runoff for January - July period was the lowest since 1977. The reservoir filled to elevation 2441.5 feet, 17.5 feet below full, on 24 August. From 24 August to 30 September the reservoir drafted about 20 feet.

COLUMBIA RIVER AND COASTAL BASINS



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1988 Report of The Columbia River Treaty Entities
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I Introduction

This annual Columbia River Treaty Entity Report is for the 1988 Water Year, 1 October 1987 through 30 September 1988. 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 1987 through 31 July 1988. The power and flood control effects downstream in Canada and the United States are described. This report is the twenty-second 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 purpose of increasing hydroelectric power generation, and for flood control in the United States of America and in Canada. 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 were two meetings of the Columbia River Treaty Entities (including the Canadian Entity Representative and U.S. Coordinators) during the year on the mornings of 2 December 1987 and 2 May 1988 in Portland, Oregon. The members of the two Entities during the period of this report were:

UNITED STATES ENTITY	CANADIAN ENTITY
Mr. James J. Jura, Chairman Administrator, Bonneville Power Administration Department of Energy Portland, Oregon	Mr. Larry I. Bell, Chairman Chairman, British Columbia Hydro and Power Authority Vancouver, B.C.
Major General Mark J. Sisinyak Division Engineer, North Pacific Division, Army Corps of Engineers, Portland, Oregon	

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
Chief, Engineering Division
North Pacific Division
Army Corps of Engineers
Portland, Oregon

John M. Hyde, Secretary
Chief, Seasonal Planning Section
Division of Power Supply
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY REPRESENTATIVE

Douglas R. Forrest, Manager
Canadian Entity Services
B.C. Hydro and Power Authority
Vancouver, B.C.

Entity 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
John M. Hyde, BPA	William N. Tivy, BCH (Part-time)
	Lawrence E. Nelson, BCH (Part-time)

Mr. Lawrence E. Nelson succeeded Mr. William N. Tivy on 1 December 1987. Mr. Tivy has served on the Operating Committee since 20 August 1981.

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
4 November 1987	Vancouver, B.C.	15
12 January 1988	Portland, Oregon	16
15 March 1988	Vancouver, B.C.	13
10 May 1988	Portland, Oregon	19
12 July 1988	Hudson's Hope, B.C.	12
13 September 1988	Vancouver, Washington	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 1987-88 Detailed Operating Plan (DOP). The Operating Committee submitted to the PEB a number of issue papers and the results of their studies to determine the impact of several proposed changes to the Assured Operating Plan (AOP) and Determination of Downstream Power Benefits (DDPB). On 2 May 1988, the Committee briefed the PEB on the AOP/DDPB, issues and the results of the studies.

Subsequently, the Entities agreed to principles and changes to the procedures for the preparation of the Assured Operating Plan and Determination of Downstream Power Benefits. With this agreement in place the Entities were able to conclude their studies for the 1992-93 AOP and DDPB. Due to the delay in completing the 1992-93 AOP and DDPB the 1993-94 studies are behind schedule.

Entity 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 Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Mark W. Maher, BPA, Co-Chairman	Heiki Walk, BCH, Chairman
Douglas D. Speers, ACE, Co-Chairman	John R. Gordon, BCH, Member

The Hydrometeorological Committee did not meet during the report period, but discussed on several matters by telephone. 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	CANADIAN SECTION
Lloyd A. Duscha, Chairman, Washington, D.C. Ronald H. Wilkerson, Member Tulsa, Oklahoma	G.M. MacNabb, Chairman Ottawa, Ontario T.R. Johnson, Member Victoria, B.C.
Herbert H. Kennon, Alternate Washington, D.C. Thomas L. Weaver, Alternate Golden, Colorado S.A. Zanganeh, Secretary Washington, D.C.	H.M. Hunt, Alternate Victoria, B.C. E.M. Clark, Alternate & Secretary Vancouver, B.C.

Mr. Wilkerson was appointed to succeed Mr. J. Emerson Harper on 18 April 1988.

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, a report on the impact of proposed changes to the AOP/DDPB, and the annual Entity report to the Board for their review. The annual joint meeting of the Permanent Engineering Board and the Entities was held on the afternoon of 2 December 1987 in Portland, Oregon. The Entities also met with the PEB on 2 May 1988 to discuss differences between the two Entities and the PEB on the assumptions for and preparation of AOPs, the methodology for determining downstream power benefits, and steps necessary to conclude a mutually acceptable agreement.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM are presently:

UNITED STATES SECTION

S.A. Zanganeh, Acting Chairman
Washington, D.C.
Gary L. Fuqua, Member
Portland, Oregon
Lee F. Johnson, Alternate Member
Washington, D.C.

CANADIAN SECTION

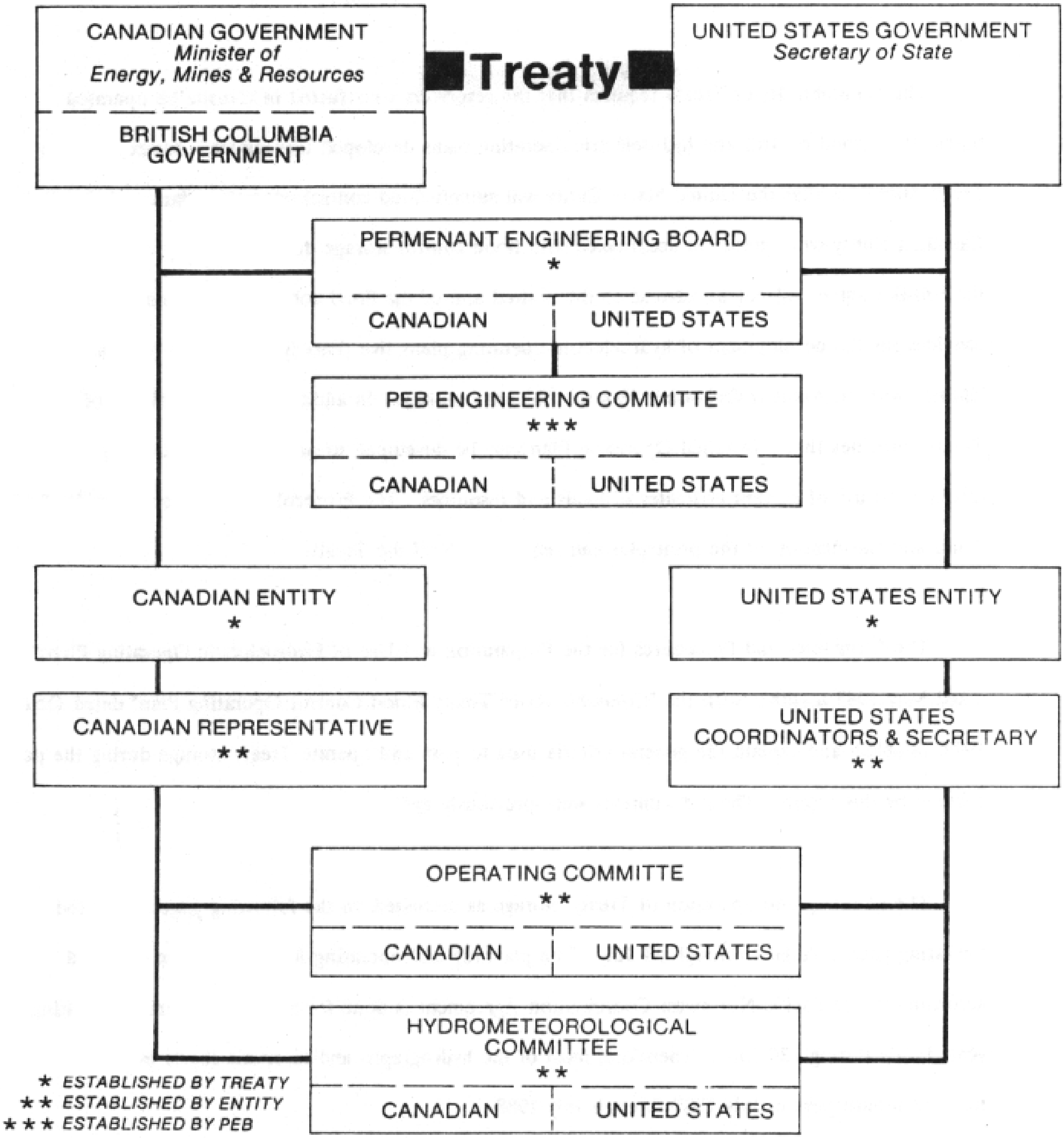
R.O. "Neil" Lyons, Chairman
Vancouver, B.C.
David B. Tanner, Member
Victoria, B.C.

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 would probably 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 May 1983 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 is done for a slightly different operating year, 1 July through 30 June. Therefore, most of the hydrographs and reservoir charts in this report are for a 13 month period, July 1987 through July 1988.

Assured Operating Plan

The Assured Operating Plan (AOP) dated September 1982 established Operating Rule Curves for Duncan, Arrow and Mica during the 1987-88 operating year. The Operating Rule Curves provided guidelines for refill levels as well as draft levels. 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 1983 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 years 1986-87 and 1987-88 the estimates of benefits resulting from operating plans designed to achieve optimum operation in both countries were 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 1987 through 31 March 1988, and 2.8 average megawatts of energy during the period from 1 April through 31 July 1988. 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 1987-88 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 October 1987. The DOP established criteria for determining the Operating Rule Curves for use in actual operations. Except for one minor change at Arrow, the DOP used the AOP critical rule curves for Canadian Projects. The Canadian Entity agreed to raise the Arrow first-year critical rule curve during the last half of April to improve the hydroregulation in the 1987-88 Pacific Northwest Coordination Agreement operating plan. The Variable Refill Curves and flood control requirements subsequent to 1 January 1988 were determined on the basis of seasonal volume runoff forecasts during actual operation. In addition, this is the first year in which 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. Subsequent to the period of this report the AOP and DDPB for 1992-93 was signed. The following tabulation indicates the date each of these were signed or approved and gives a description of the agreement:

Date Agreement Signed by Entities	Description
2 December 1987	Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1987 through 31 July 1988, dated October 1987.
2 December 1987	Columbia River Treaty Entities Agreement to Study Several Outstanding Issues Concerning the Assured Operating Plan and Determination of Downstream Power Benefit Studies.

28 July 1988	Columbia River Treaty Entity Agreement on Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies.
12 August 1988	Columbia River Treaty Entity Agreement on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies.
14 October 1988	Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefit Studies for Operating Year 1992-93, dated September 1988.

Long Term Non-Treaty Storage Contract

In accordance with the 9 April 1984 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 the Agreement to insure that they did not adversely impact operation of Treaty storage required by the Detailed Operating Plan.

Agreements on Principles and Procedures

As a result of extensive study of the technical implications of various alternative interpretations of the Treaty and related documents, and examination of the legal support for such alternatives, the Entities agreed on an interpretation that will be used in the development of future Assured Operating Plans and the Determination of Downstream Benefits. This is embodied in the agreed to principles dated 28 July 1988 and the corresponding procedures dated 12 August 1988. The documents clarify the definition of the loads of the Pacific Northwest area, thermal resources which may be displaced and how these resources are assumed to operate in calculating useable energy.

The Agreements also describes the streamflows to be used in the studies, and the way in which the effects of irrigation should be included over the course of time. There are also a number of interpretations on how individual plants should be operated when they are included in the studies leading up to the development of the Assured Operating Plan and Determination of Downstream Benefits.

Included in the Agreement is a way in which energy may be shifted between years of the Critical Period, and the way in which any resulting benefits should be determined. The Agreements also acknowledge that the U.S. firm energy may be shaped in the Step I study.

These Agreements represent another milestone in the cooperative effort to solve long-standing problems associated with development of an operating plan to the mutual benefit of both countries.

IV Weather and Streamflow

Weather

Chart 1 is a geographical illustration of the seasonal precipitation in the Columbia River Basin, in percent of normal, for the period 1 October 1987 through 30 September 1988. Chart 2 shows an index of the accumulated snowpack in the Columbia Basin above The Dalles in percent of normal for the period 1 January through 31 May 1988. Indices of temperature and precipitation in the Columbia Basin for the period 1 September 1987 through 31 August 1988 are shown on Charts 3, 4, and 5. The following paragraphs describe significant weather events between 1 August 1987 and 30 September 1988.

Weather in the basin fell into three groupings: the months of September through November were warm and dry, January and February were variable and the other months of the year were generally near normal. During September and October the Columbia Basin was generally under the influence of high pressure ridges that forced weather systems either into British Columbia or into California. This left the Northwest practically rainless as the record zero precipitation during September at Boise, Idaho, demonstrated. The more northerly storm track, however, did provide some precipitation to the Canadian portion of the basin as indicated by the 30 percent of normal September precipitation above Grand Coulee compared to only 5 percent in the Snake Basin. October was even drier with only 10 percent above Grand Coulee and 7 percent in the Snake Basin. There was definitely a beginning of a drought in the making with the Columbia Basin above The Dalles having only 20 percent of normal precipitation in September and 11 percent in October. The weather during the first week in November continued the pattern of the previous two months. Then, for the next two weeks, a series of storms entered the basin and deposited near normal amounts of precipitation. However, with the first and last weeks dry, November ended with only 56 percent of normal precipitation above The Dalles.

The stormy pattern of December began on the first with a deep low pressure system in the Gulf of Alaska sending storms onto the Oregon and Washington coasts. These storms, and especially the heavy storm on 9 December produced above normal precipitation in the coastal and Cascade basins. Unfortunately, these storms failed to penetrate much beyond the Cascades and consequently the eastern basins, especially the Snake Basin, did not receive normal precipitation. Precipitation during the latter half of the month was generally below normal, but, because of the heavy precipitation during the first half, the averages for December were 91 percent for the basin above Grand Coulee, 82 percent above Ice Harbor, however, much above normal precipitation in eastern Washington and eastern Oregon caused the precipitation at The Dalles to rise to 98 percent of average.

Both January and February began dry, followed by a week to 10 days of near normal precipitation, and ending with two weeks of dry weather. Both months ended with below normal precipitation. Precipitation indices in January and February for the basin above The Dalles were 74 and 61 percent of average, respectively. The drought concerns continued since the seasonal (September - February) precipitation for the basin above The Dalles was only 58 percent of normal.

The weather from March through August was near normal. Each month had a series of warm and dry and then wet and cool periods. In all cases the end of month precipitation total for the Columbia Basin was near normal. Warm temperatures, to induce snowmelt, were well scattered throughout the snowmelt period and were of short duration. For the period 5-10 March the temperatures in the basin were approximately 5 degrees Fahrenheit above normal, 5-13 April they were 12 degrees Fahrenheit above normal, and during 10-12, 15-16, and 21-22 May they were 7 degrees to 10 degrees Fahrenheit above normal. Little or no snow remained in the mountains after the end of May.

The preliminary and final monthly precipitation indices for the Columbia Basin above The Dalles are shown below. The final precipitation differs from the preliminary indices because the preliminary index is computed using 16 generally representative stations. The final index is based on

60 stations and is computed at the end of each month after all the data are collected. The following tabulation shows the 25-year average (1961-1985) monthly precipitation and the monthly indices for Water Year 1988 (WY 88).

Month	25-year Average (in.)	WY-88 Indices Final(%)	Prelim(%)
Oct 87	1.75	11	12
Nov 87	2.78	56	53
Dec 87	3.35	98	95
Jan 88	3.10	74	64
Feb 88	2.19	61	51
Mar 88	1.93	113	106
Apr 88	1.65	141	135
May 88	1.80	118	89
Jun 88	1.93	87	82
Jul 88	1.06	83	102
Aug 88	1.27	39	48
Sep 88	1.51	85	88

Streamflow

The observed inflow and outflow hydrographs for the period 1 July 1987 to 31 July 1988 are shown on Charts 6 through 9 for the four Treaty reservoirs. 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 unregulated flows at The Dalles during the April through July 1988 period. In addition to the unregulated hydrograph, a hydrograph showing the flows that would have occurred if regulated only by the Treaty reservoirs is also shown.

Streamflows in the basin above The Dalles were below normal for the entire operating year. These flows were a direct reflection of the dry conditions as the precipitation for the basin was below normal for the operating year. The peak regulated discharge was 236,000 cfs at The Dalles.

The 1987-88 monthly modified streamflows and the average monthly flows for the 1929-1978 period are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These modified flows have been adjusted for storage in lakes and reservoirs to exclude the effects of regulation. They are also adjusted to the 1980 level of development for irrigation. A comparison of 1988 values with the 1929-1978 period of record shows that for Grand Coulee the 1988 flow was the fourth lowest in the period of record, for The Dalles, the 1988 flow was fifth lowest compared to the 50-year period of record.

	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Modified Flow 1987-1988	Average 1929-1978	Modified Flow 1987-1988	Average 1929-1978
Aug 87	70,350	103,142	92,510	139,054
Sep 87	46,710	64,457	68,630	97,214
Oct 87	23,750	50,650	51,630	87,349
Nov 87	24,180	45,525	48,430	89,536
Dec 87	26,850	43,793	57,100	95,166
Jan 88	20,680	38,482	53,920	91,901
Feb 88	23,450	41,045	60,570	102,817
Mar 88	36,460	50,359	81,030	122,728
Apr 88	126,000	117,432	210,900	221,814
May 88	208,800	272,024	314,600	421,758
Jun 88	239,470	325,692	326,180	479,654
Jul 88	131,880	195,586	162,870	216,610
YEAR	81,565	112,678	127,334	180,649

Seasonal Runoff Forecasts and Volumes

Observed 1988 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 1961-80 Average
Libby Reservoir Inflow	4,630	71
Duncan Reservoir Inflow	2,080	101
Mica Reservoir Inflow	10,700	92
Arrow Reservoir Inflow	22,200	84
Columbia River at Birchbank	36,700	89
Grand Coulee Reservoir Inflow	46,900	75
Snake River at Lower Granite Dam	13,100	54
Columbia River at The Dalles	66,400	67

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 1988 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 United States Columbia River Forecasting Service. The 1 April 1988 forecast of January through July runoff for the Columbia River above The Dalles was 74.0 MAF and the actual observed runoff was 72.7 MAF, a 1.3 percent differential. The following tabulation summarizes monthly forecasts since 1970 of the January through July runoff for the Columbia River above The Dalles compared to the actual runoff measured in millions of acre-feet (MAF):

Year	Jan	Feb	Mar	Apr	May	Jun	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	135.0	140.0	146.0	149.0	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	72.7

V Reservoir Operation

General

The 1987-88 operating year was the second consecutive drought year in the Columbia Basin, and the third low water year in the past four years. At The Dalles, observed January-July runoff was the eighth lowest since 1928.

The operating year began with the coordinated reservoir system officially filled to about 98.5% of capacity on 31 July 1987. This allowed the first-year firm energy load carrying capability to be adopted for the 1988 operating year. The system remained close to full for most of the summer although 5-10 feet of drawdown occurred at most US storage reservoirs by late August. Further draft requirements were avoided by draft of non-Treaty storage and by energy exchange agreements. Increased draft began after Labor Day to meet firm energy loads. The system operated in accordance with proportional draft requirements throughout autumn, with draft levels reaching 15% between third and fourth-year critical rule curves by the end of December.

The 1 January water supply forecast for The Dalles was 79.2 MAF, the lowest since 1977 when it was 75.7 MAF. Based on this forecast, the outlook for complete refill of the reservoir system was poor, with individual reservoirs expected to be 10 to 50 feet from full on 31 July. Even so, the system continued to be drafted heavily throughout the winter for firm loads. Energy purchases by BPA, special storage arrangements and return of storage from outside the system all helped reduce draft requirements to some degree.

Water supply forecasts continued to drop throughout the winter and springtime. Consequently, the reservoir system was not operated on a daily basis for flood control anytime during 1988. The only significant rise in lower Columbia River flows occurred during the annual Water Budget operation. Water Budget flows were released from Grand Coulee between 9 May and 10 June. The average flow at

The Dalles during this period was 200,000 cfs and the year's peak flow of 236,000 cfs occurred on 11 May.

By 31 July, the coordinated system reached about 84 percent of its full capacity, requiring that third-year FELCC be adopted for the 1988-89 operating year. Ironically, third-year FELCC for the coordinated system is about 350 aMW greater than second year.

Mica Reservoir

As shown in Chart 6, Treaty storage at the Mica reservoir (Kinbasket Lake) was refilled by 14 July 1987. Since all of the non-Treaty storage space at Mica was not refilled at that time, the actual elevation was only 2462.2 feet, or approximately 13 feet below its full pool elevation of 2475.0 feet. During August and September, B.C. Hydro and BPA non-Treaty storage was drafted, causing the reservoir to reach elevation 2454.0 feet by 30 September. Treaty storage draft at Mica began on 5 October when the inflows receded to below 10,000 cfs, the Mica storage discharge requirement for the month. By 31 October, two feet of Mica Treaty storage was drafted, to meet the Mica flood control requirement. Since the Treaty storage levels at the Arrow reservoir were below the Mica discharge trigger points, the Treaty storage discharges at Mica for November and December were increased from 23,000 cfs to 28,000 cfs according to the 1987/88 Detailed Operating Plan. These increases resulted in an increased draft rate at Mica. By 31 December, the reservoir was drafted to elevation 2417.6 feet, approximately 12 feet below its Operating Rule Curve after adjusting for the non-Treaty storage. Daily outflows, including non-Treaty storage releases, varied between 12,500 cfs and 40,000 cfs during this period. Mica continued to draft heavily from January until early April. On 15 April, Mica reached elevation 2365.2 feet, its lowest level since the reservoir was first filled in 1976.

Mica began filling on 16 April. During the refill period the project outflow was reduced, at times, to as low as zero discharge. Inflows into the reservoir were near average during May and June, peaking at 78,940 cfs on 8 June. During this period, the reservoir quickly filled and reached elevation 2427.0 feet on 30 June, slightly above its Operating Rule Curve.

The project continued to fill during July and early August and the Treaty storage space was refilled on 10 August. Since the non-Treaty storage space at Mica was not refilled, the actual reservoir level on 10 August was only 2443.2 feet, or 32 feet below full pool. Approximately 9 feet of this shortage to refill was due to drafting of the B.C. Hydro live storage earlier in the summer. The Mica discharge was then increased to equal inflow, maintaining the reservoir level near 2443.0 feet. During September, draft of B.C. Hydro live storage at Mica caused the reservoir to reach elevation 2440.3 feet on 21 September.

Revelstoke Reservoir

During this past operating year, Revelstoke project was basically operated as a run of the river plant, maintaining the reservoir within 5 feet of its normal full pool, elevation 1880.0 feet. From 26 August to 2 September 1988, unit problems at Mica resulted in Revelstoke drafting as low as 1873.0 feet. The reservoir was subsequently refilled to full pool on 10 September.

Arrow Reservoir

As shown in Chart 7, Arrow reservoir was at elevation 1440.1 feet, about four feet below its normal full pool, elevation 1444.0 feet, on 30 July 1987. Some Treaty storage was temporarily held in the Revelstoke reservoir. The project then discharged inflow, maintaining its level near elevation 1440.0 feet through August. Beginning in September, Arrow was drafted to meet proportional draft requirements. The project outflows were increased to as high as 78,000 cfs for several days early in the month. By 31 October, the Treaty storage at Arrow was drafted below the level that would trigger higher Treaty storage release from Mica. Consequently, the Mica Treaty outflow in November was increased from 23,000 cfs to 28,000 cfs. During the period from 11 to 20 November, the project outflow at Arrow was reduced to accommodate the transfer of non-Treaty storage to Mica. The reservoir filled approximately three feet to elevation 1426.8 feet before the drafting was resumed. By 31 December, the reservoir was drafted to elevation 1415.1 feet, well below its Operating Rule Curve. Arrow continued drafting during January and February with the project discharging up to 79,000 cfs. On 21 February, the reservoir reached elevation 1385.5 feet, its lowest level for the current operating year.

Arrow began refilling in late February. It filled slowly through March, reaching elevation 1391.6 feet on 31 March. During the period from 24 April to 8 May, the discharge at Arrow was reduced to 10,000 cfs, accelerating the filling process. The project continued filling steadily through June and July. By 31 July, Arrow reached its highest level for the summer, elevation 1439.2 feet, about five feet below normal full pool. The adjusted level, however, was elevation 1436.5 feet, with the difference being some B.C. Hydro non-Treaty storage which had previously been transferred from Mica to Arrow.

Due to the low summer runoff, Arrow soon began drafting Treaty storage to meet downstream storage requirements. To prevent a large drawdown, which could cause Arrow to drop below the level required for summer recreation, B.C. Hydro increased non-Treaty storage releases from Mica and Revelstoke to transfer water to Arrow for the period from August until early September. As a result, Arrow was maintained near 1436.0 feet during this period. Beginning 6 September, the level of Arrow reservoir dropped rapidly due to the return of non-Treaty storage to Mica and the drafting of Treaty storage to meet downstream requirements. The reservoir reached elevation 1426.8 feet on 20 September.

Duncan Reservoir

As shown in Chart 8, Duncan reached full pool on 3 July 1987. The project then passed inflow, maintaining full pool until early September. On 6 September, the outflow was increased to 10,000 cfs and maintained at 10,000 cfs until 16 September, drafting about ten feet of storage. From October until early November, discharges at the project were curtailed to minimize spill at power plants on the Kootenay River. The reservoir filled slowly, reaching elevation 1884.8 feet on 7 November. Storage draft resumed on 8 November. By 31 December, the reservoir was drafted to elevation 1848.9 feet, approximately 17 feet below its Operating Rule Curve. The project continued to draft heavily through January and February with project outflows varying between 4,000 cfs and 8,000 cfs. On 26 February, the Duncan reservoir reached its minimum level of 1794.2 feet. The project then passed inflow, maintaining the level near elevation 1794.2 feet.

Duncan project began filling about mid-April as the discharge was reduced to as low as 100 cfs. With above average inflows into the reservoir during May and June, the project filled quickly, reaching elevation 1879.9 feet on 30 June, eight feet above its Operating Rule Curve. The runoff peaked with a daily average flow of 15,940 cfs on 17 June. Beginning 4 July, the discharge at Duncan was increased to reduce the rate of filling as the reservoir approached full pool. By 14 July, Duncan was discharging 6,000 cfs. The project continued to fill and reached full pool on 26 July. Storage draft at the Duncan reservoir began 10 August, as required to supply storage to downstream projects. The project outflow was increased up to 10,000 cfs, drafting the reservoir elevation to 1881.8 feet by 31 August. Beginning 11 September, the project discharge was reduced to 100 cfs to minimize spill at power plants on the Kootenay River.

Libby Reservoir

During the summer of 1987 Lake Koocanusa reached elevation 2454.1 feet on 29 June and was held in its top five feet through 8 September. The lake, as shown on Chart 9, was maintained in its top foot from 13 July to 18 August. Approximately five feet of drawdown occurred between 18 August and Labor Day to meet firm power requirements. After Labor Day the lake began drafting more rapidly and was at elevation 2444.5 feet, its proportional draft point, on 30 September.

The project continued drafting throughout autumn with the October-November outflow averaging 16,400 cfs. The outflow was reduced in the second half of November to as low as 4,000 cfs and remained relatively low in December, averaging 9,100 cfs, as BPA used other resources, including energy purchases, to meet firm power requirements. On 31 December, the reservoir was at elevation 2392 feet, well above the proportional draft point of 2341.5 feet.

Projections in early January, based on the January water supply forecast, indicated the lake had a very low refill probability of complete refill and would probably fall about 25-50 feet short, depending on outflow requirements. Despite this outlook, it was necessary in early January to increase the outflow to full powerhouse capacity, about 24,000 cfs, to meet firm loads. The reservoir continued drafting rapidly in February, reaching elevation 2322.8 feet, about five feet above the proportional draft point, on 29 February. In early March, the outflow was reduced to minimum, 3,000 cfs, and the reservoir reached its lowest point of the year, elevation 2317.4, on 26 March. Numerous news releases and statements were made to the public regarding the drought and anticipated low summertime water levels. In addition, several boatramps were extended during the springtime. Natural flows at Libby for the September-March period were the sixth lowest in the 1928-88 period of record.

Inflows to Lake Koocanusa began rising in mid-April and the seasonal peak of 45,900 cfs occurred on 9 June. By late June the inflow had receded to less than 20,000 cfs. The project outflow was held at 3,000 cfs until 24 August. The lake reached its maximum level of elevation 2441.5, 17.5 feet from full, on this date. Approximately two feet of drawdown occurred between 24 August and Labor Day. The January-July observed runoff was only 73% of normal and was the lowest since 1977.

Kootenay Lake

As shown in Chart 10, Kootenay Lake passed inflow, maintaining the water level near elevation 1743.0 feet until 31 August 1987. On 1 September, the lake began filling when the discharges were reduced to prevent spill at the Brilliant plant. The lake reached elevation 1745.0 feet on 19 September, slightly below the maximum level (elevation 1745.32 feet) permitted by the International Joint Commission Rule Curve. From October until December, Kootenay Lake operated between elevations 1744.5 feet and 1745.0 feet with discharges varying between 16,000 cfs and 28,000 cfs. Kootenay Lake began drafting in early January to meet the IJC Rule Curve. The lake continued drafting through February and March, discharging up to 38,000 cfs. On 3 April, Kootenay Lake reached its lowest level for the current operating year, elevation 1738.9 feet.

Inflows began increasing in mid-April, filling the lake to elevation 1741.8 feet by 23 April. Between 24 April and 8 May, the lake remained near elevation 1741.8, as inflows receded. The lake resumed filling on 9 May and reached its highest level for the current operating year, elevation 1745.6 feet, on 30 May. The lake then slowly drafted through June, reaching elevation 1743.32 feet at Nelson on 1 July. During July and August, Kootenay Lake passed inflow, maintaining the water level near elevation 1743.0 feet. During August, discharges at Duncan were increased to keep the Brilliant plant operating at capacity while maintaining the lake level near 1743.0 feet. Inflows into Kootenay Lake then increased in September due to higher releases from the upstream projects. With outflows curtailed to minimize spill at the Brilliant plant, Kootenay Lake began filling and reached elevation 1744.6 feet on 17 September.

VI Power and Flood Control Accomplishments

General

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

1. "Detailed Operating Plan for Columbia River Treaty Storage - 1 August 1987 through 31 July 1988," dated October 1987.
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 1987-88 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 1987-88 Assured Operating Plan prepared in 1982, was used as the basis for the preparation of the 1987-88 Detailed Operating Plan.

Power

The Canadian Entitlement to downstream power benefits from Duncan, Arrow and Mica for the 1987-88 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 Agreement was 393 average megawatts at rates up to 1,052 megawatts, from

1 August 1987, through 31 March 1988, and 368 average megawatts, at rates up to 1,012 megawatts, from 1 April 1988, through 31 July 1988. All CSPE power was used to meet Pacific Northwest loads.

The Coordinated System reservoirs were near full on 1 August 1987, and after being drafted down during the 1987-88 operating year, refilled to only 84 percent of full on 31 July 1988. The following table shows the status of the energy stored in coordinated system reservoirs in billions of kilowatt-hours, at the end of each month compared to Operating Rule Curves during the 1987-88 operating year:

Month	Operating Rule Curve	Actual	Difference
Aug 87	45.6	43.6	-2.0
Sep 87	42.6	39.6	-3.0
Oct 87	38.9	33.9	-5.0
Nov 87	34.8	29.0	-5.8
Dec 87	30.9	23.4	-7.5
Jan 88	25.8	16.8	-9.0
Feb 88	22.5	11.9	-10.6
Mar 88	22.1	8.6	-13.5
Apr 88	24.2	14.3	-9.9
May 88	32.2	24.4	-7.8
Jun 88	42.1	35.0	-7.1
Jul 88	45.1	37.8	-7.3

During the January-June period of 1988, volume runoff forecasts to cyclic reservoirs were insufficient to lower the Operating Rule Curves below the Assured Refill Curves.

The following table shows BPA nonfirm and surplus firm sales in megawatt-hours to northwest and southwest utilities during the 1987-88 operating year. Nonfirm sales were made only during the Water Budget operation from 7 May through 9 June.

Period	To Northwest Utilities		To Southwest Utilities	
	Nonfirm	Surplus Firm	Nonfirm	Surplus Firm
Aug 87	0	11,933	0	194,463
Sep 87	0	39,637	0	899,229
Oct 87	0	19,621	0	1,072,561
Nov 87	0	33,924	0	117,161
Dec 87	0	36,250	0	145,310
Jan 88	0	0	0	93,586
Feb 88	0	0	0	5,986
Mar 88	0	0	0	6,248
Apr 88	0	0	0	6,903
May 88	131,919	0	473,682	24,905
Jun 88	104,141	8,800	226,517	73,803
Jul 88	0	8,000	0	45,918
TOTAL	236,060	158,165	700,199	2,686,073

Flood Control

The Columbia River Basin reservoir system, including the Columbia River Treaty projects, was not operated on a daily basis for flood control anytime during 1988. This is the fourth year in a row in which daily operation for flood control during the spring runoff has not been necessary. Flood control during the 1988 runoff was provided by the normal refill operation of the Treaty reservoirs and other storage reservoirs in the Columbia River Basin. The observed and unregulated hydrographs for the Columbia River at The Dalles between 1 July 1987 and 31 July 1988 are shown on Chart 14. The unregulated peak flow at The Dalles would have been 392,000 cfs on 29 May 88 and it was controlled to a maximum of 236,000 cfs on 11 May 88.

The observed peak stage at Vancouver, Washington was 10.0 feet on 15 January 88 and the unregulated stage would have been 14.7 feet on 4 June 88. 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.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. The results of these computations started out on 1 January 1988 and on 1 February at 200,000 cfs, then increased to 210,000 cfs on 1 May. Data for the 1 May ICF computation are given in Table 6.

Table 1
Unregulated Runoff Volume Forecasts
Millions of Acre-Feet
1988

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	1.8	20.2	10.1	4.9	69.9
February	1.8	19.3	9.9	4.6	66.9
March	1.9	19.9	10.3	4.3	65.9
April	1.8	20.5	10.5	4.6	68.1
May	1.8	22.4	10.7	4.7	70.4
June	1.8	22.0	10.6	4.8	69.3
Actual	2.1	22.2	10.1	4.6	66.4

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

Table 2

95 Percent Confidence Forecast and Variable Energy Content Curve Mica 1988

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		4206.2	4213.9	4379.1	4386.0	4527.7	4477.5
2 95% FORECAST ERROR, KSFD		663.5	537.9	498.3	485.6	457.9	448.9
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD[2] ..		3540.4	3676.0	3880.8	3900.4	4069.8	4028.8
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	121.6	232.4	582.6	1462.8
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		3540.4	3676.0	3759.2	3668.0	3487.2	2565.8
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		3540.4					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		2180.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		2168.8					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		2443.2					
JAN 31 ECC, FT[7]		2438.7					
BASE ECC, FT	2438.7						
LOWER LIMIT, FT	2402.0						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		97.9	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		3466.1	3598.8				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1760.0	1760.0				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		1823.1	1690.4				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		2436.0	2433.6				
FEB 28 ECC, FT[7]		2426.6	2426.6				
BASE ECC, FT	2426.6						
LOWER LIMIT, FT	2394.2						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		95.6	95.6	97.7			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		3384.6	3514.7	3672.7			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1295.0	1295.0	1295.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		1439.6	1309.9	1151.5			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		2427.7	2425.8	2422.4			
MAR 31 ECC, FT[7]		2417.0	2417.0	2417.0			
BASE ECC, FT	2417.0						
LOWER LIMIT, FT	2394.2						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME ..		91.0	91.0	91.1	91.1		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		3221.8	3345.2	3496.1	3491.9		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		920.0	920.0	920.0	920.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		1227.4	1104.0	953.1	957.3		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		2423.1	2421.4	2418.1	2417.0		
APR 30 ECC, FT[7]		2408.6	2408.6	2408.6	2408.6		
BASE ECC, FT	2408.6						
LOWER LIMIT, FT	2394.1						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME ..		73.7	73.7	75.3	77.1	81.0	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		2609.3	2709.2	2830.7	2828.0	2824.6	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		610.0	610.0	610.0	610.0	610.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		1529.9	1430.0	1308.5	1311.2	1314.6	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		2429.7	2428.3	2425.8	2424.9	2425.0	
MAY 31 ECC, FT[7]		2414.0	2414.0	2414.0	2414.0	2414.0	
BASE ECC, FT	2414.0						
LOWER LIMIT, FT	2394.1						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME ..		36.5	36.5	37.3	38.2	40.1	49.5
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		1292.2	1341.7	1402.2	1401.2	1398.4	1270.1
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		310.0	310.0	310.0	310.0	310.0	310.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		2547.0	2497.5	2437.0	2438.0	2440.8	2569.1
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		2450.9	2449.5	2448.3	2448.7	2448.8	2451.4
JUN 30 ECC, FT[7]		2443.6	2443.6	2443.6	2443.6	2443.6	2443.6
BASE ECC, FT	2443.6						
LOWER LIMIT, FT	2394.1						
JUL 31 ECC, FT	2470.1	2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (3579.6 KSFD) PLUS TWO PRECEDING
6 FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973
7 LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR

Table 3
95 Percent Confidence Forecast and Variable Energy Content Curve
Arrow 1988

	INITIAL	JAN 1 LOCAL	FEB 1 LOCAL	MAR 1 LOCAL	APR 1 LOCAL	MAY 1 LOCAL	JUN 1 LOCAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		4686.0	4611.2	4781.2	4765.1	5545.1	5438.7
2 95% FORECAST ERROR, KSFD		1130.6	948.7	802.3	633.6	555.5	557.2
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD[2]		3555.4	3662.5	3978.9	4131.5	4989.6	4881.5
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	182.2	402.0	1139.3	2514.4
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		3555.4	3662.5	3796.7	3729.5	3850.3	2367.1
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		3555.4					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		4334.0					
MICA REFILL REQUIREMENTS, KSFD[8]		2180.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		2178.2					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		1421.4					
JAN 31 ECC, FT[7]		1411.2					
BASE ECC, FT	1411.2						
LOWER LIMIT, FT	1392.1						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.2	97.2				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		3455.8	3560.0				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		4194.0	4194.0				
MICA REFILL REQUIREMENTS, KSFD[8]		1760.0	1760.0				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		2557.7	2453.6				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		1427.8	1426.0				
FEB 28 ECC, FT[7]		1399.8	1399.8				
BASE ECC, FT	1399.8						
LOWER LIMIT, FT	1383.8						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		93.8	93.8	96.5			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		3335.0	3435.4	3663.8			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		4039.0	4039.0	4039.0			
MICA REFILL REQUIREMENTS, KSFD[8]		1295.0	1295.0	1295.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		2988.6	2888.2	2659.8			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		1434.8	1433.2	1429.5			
MAR 31 ECC, FT[7]		1406.7	1406.7	1406.7			
BASE ECC, FT	1406.7						
LOWER LIMIT, FT	1382.3						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		86.1	86.1	88.6	91.8		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		3061.2	3153.4	3363.9	3423.7		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		3379.0	3379.0	3379.0	3379.0		
MICA REFILL REQUIREMENTS, KSFD[8]		920.0	920.0	920.0	920.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		2977.4	2885.2	2674.7	2614.9		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		1434.6	1433.1	1429.7	1428.7		
APR 30 ECC, FT[7]		1409.6	1409.6	1409.6	1409.6		
BASE ECC, FT	1409.6						
LOWER LIMIT, FT	1377.9						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		62.2	62.2	64.0	66.3	72.3	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		2211.5	2278.1	2429.9	2472.7	2783.8	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		2418.0	2418.0	2418.0	2418.0	2418.0	
MICA REFILL REQUIREMENTS, KSFD[8]		610.0	610.0	610.0	610.0	610.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		3176.1	3109.5	2957.7	2914.9	2603.8	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		1437.8	1436.7	1434.3	1433.6	1428.5	
MAY 31 ECC, FT[7]		1425.6	1425.6	1425.6	1425.6	1425.6	
BASE ECC, FT	1425.6						
LOWER LIMIT, FT	1377.9						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		26.8	26.8	27.6	28.6	31.2	43.2
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		952.8	981.6	1047.9	1066.6	1201.3	1022.6
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		1488.0	1488.0	1488.0	1488.0	1488.0	1488.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		310.0	310.0	310.0	310.0	310.0	310.0
MICA REFILL REQUIREMENTS, KSFD[9]		3804.7	3776.1	3709.7	3691.0	3556.3	3735.0
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		1444.0	1444.0	1444.0	1444.0	1444.0	1444.0
JUN 30 ECC, FT[7]		1444.0	1444.0	1444.0	1444.0	1444.0	1444.0
BASE ECC, FT	1444.0						
LOWER LIMIT, FT	1377.9						
JUL 31 ECC, FT		1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

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6 FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973
7 LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR
8 USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3
9 FOR ARROW TOTAL: MICA FULL CONTENT LESS ENERGY CONTENT CURVE

Table 4

95 Percent Confidence Forecast and Variable Energy Content Curve Duncan 1988

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		782.5	784.2	827.1	801.6	888.9	899.5
2 95% FORECAST ERROR, KSFD		154.1	118.6	113.5	105.6	95.4	94.0
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD[2] ..		628.4	665.6	713.6	696.0	793.5	805.5
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	14.4	37.5	135.2	346.4
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		628.4	665.6	699.2	658.5	658.3	459.1
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		628.4					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		213.3					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		290.7					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		1841.6					
JAN 31 ECC, FT[7]		1834.7					
BASE ECC, FT	1834.7						
LOWER LIMIT, FT	1794.5						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		97.9	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		615.2	651.6				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		210.5	210.5				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		301.1	264.7				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		1843.0	1838.2				
FEB 28 ECC, FT[7]		1834.9	1834.9				
BASE ECC, FT	1834.9						
LOWER LIMIT, FT	1794.6						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		95.5	95.5	97.5			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		600.1	635.6	681.7			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		207.4	207.4	207.4			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		313.1	277.6	224.9			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		1844.6	1839.9	1832.7			
MAR 31 ECC, FT[7]		1836.9	1836.9	1832.7			
BASE ECC, FT	1836.9						
LOWER LIMIT, FT	1794.4						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME ..		90.1	90.1	92.0	94.3		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		566.2	599.7	643.3	621.0		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		156.4	156.4	156.4	156.4		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		296.0	262.5	218.9	241.2		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		1842.3	1837.9	1831.8	1834.9		
APR 30 ECC, FT[7]		1833.8	1833.8	1831.8	1833.8		
BASE ECC, FT	1833.8						
LOWER LIMIT, FT	1794.2						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME ..		69.7	69.7	71.2	73.0	77.4	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		438.0	463.9	497.8	480.7	509.5	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		103.7	103.7	103.7	103.7	103.7	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		371.5	345.6	311.7	328.8	300.0	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		1852.2	1849.0	1844.5	1846.7	1842.9	
MAY 31 ECC, FT[7]		1848.3	1848.3	1844.5	1846.7	1842.9	
BASE ECC, FT	1848.3						
LOWER LIMIT, FT	1794.2						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME ..		32.4	32.4	33.1	33.9	36.0	46.5
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		203.6	215.7	231.4	223.2	237.0	213.5
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		52.7	52.7	52.7	52.7	52.7	52.7
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		554.9	542.8	527.1	535.3	521.5	545.0
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		1874.7	1873.3	1871.5	1872.3	1870.7	1873.5
JUN 30 ECC, FT[7]		1871.9	1871.9	1871.5	1871.9	1870.7	1871.9
BASE ECC, FT	1871.9						
LOWER LIMIT, FT	1794.2						
JUL 31 ECC, FT		1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

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

Table 5
95 Percent Confidence Forecast and Variable Energy Content Curve Libby 1988

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE JAN 1 - JUL 31 INFLOW, KSFD		2537.5	2402.6	2235.6	2350.8	2410.6	2467.0
2 95% FORECAST ERROR, KSFD		886.8	606.4	552.5	533.4	474.5	367.5
3 OBSERVED JAN 1 - DATE INFLOW, KSFD		0.0	86.9	155.9	240.4	510.9	1208.6
4 95% CONF DATE - JUL 31 INFLOW, KSFD[1]		1650.7	1709.2	1527.2	1577.0	1425.2	890.9
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		97.1					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[2]		1603.5					
FEB MINIMUM FLOW REQUIREMENTS, CFS[3]		4000.0					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD[4]		804.2					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		1711.2					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		2421.9					
JAN 31 ECC, FT[7]		2410.6					
BASE ECC, FT	2410.6						
LOWER LIMIT, FT	2313.5						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		94.5	97.3				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		1559.4	1662.2				
MAR MINIMUM FLOW REQUIREMENT, CFS[3]		4000.0	4000.0				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		692.2	692.2				
MIN. FEB 1 RESERVOIR CONTENT, KSFD[5]		1643.3	1540.5				
MIN. FEB 1 RESERVOIR ELEVATION, FT[6]		2418.5	2413.0				
FEB 28 ECC, FT[7]		2407.6	2407.6				
BASE ECC, FT	2407.6						
LOWER LIMIT, FT	2303.8						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		91.2	93.9	96.6			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		1506.1	1605.3	1474.9			
APR MINIMUM FLOW REQUIREMENT, CFS[3]		4200.0	4200.0	4200.0			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		568.2	568.2	568.2			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		1572.6	1473.4	1603.8			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		2414.7	2409.4	2416.4			
MAR 31 ECC, FT[7]		2404.4	2404.4	2404.4			
BASE ECC, FT	2404.4						
LOWER LIMIT, FT	2287.0						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME ..		83.2	85.7	88.1	91.2		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		1373.5	1464.0	1345.1	1438.3		
MAY MINIMUM FLOW REQUIREMENT, CFS[3]		4200.0	4200.0	4200.0	4200.0		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		442.2	442.2	442.2	442.2		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		1579.2	1488.7	1607.6	1514.4		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		2415.1	2410.3	2416.6	2411.6		
APR 30 ECC, FT[7]		2403.0	2403.0	2403.0	2403.0		
BASE ECC, FT	2403.0						
LOWER LIMIT, FT	2287.0						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME ..		56.7	57.5	59.1	61.2	67.1	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		938.6	982.8	903.0	965.5	956.7	
JUN MINIMUM FLOW REQUIREMENT, CFS[3]		4200.0	4200.0	4200.0	4200.0	4200.0	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		312.0	312.0	312.0	312.0	312.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		1883.9	1839.7	1919.5	1857.0	1865.8	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		2430.0	2428.0	2431.8	2428.8	2429.2	
MAY 31 ECC, FT[7]		2427.0	2427.0	2427.0	2427.0	2427.0	
BASE ECC, FT	2427.0						
LOWER LIMIT, FT	2287.0						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME ..		19.4	20.0	20.5	21.3	23.3	34.7
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		320.4	341.5	313.7	335.4	332.4	309.5
JUN MINIMUM FLOW REQUIREMENT, CFS[3]		6000.0	6000.0	6000.0	6000.0	6000.0	6000.0
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		186.0	186.0	186.0	186.1	186.0	186.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		2376.1	2355.0	2382.8	2361.1	2364.1	2387.0
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		2453.2	2452.2	2453.5	2452.5	2452.6	2453.6
JUN 30 ECC, FT[7]		2452.5	2452.2	2452.5	2452.5	2452.5	2452.5
BASE ECC, FT	2452.5						
LOWER LIMIT, FT	2287.0						
JUL 31 ECC, FT		2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN 1 - JUL 31 FORECAST, EARLYBIRD, MAF							

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Table 6

Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 1988

1 May Forecast of May-August Unregulated Runoff Volume, MAF		58.0
Less Estimated Depletions, MAF		1.5
Less Upstream Storage Corrections, MAF		
MICA	6.0	
ARROW	5.0	
LIBBY	3.5	
DUNCAN	1.3	
HUNGRY HORSE	1.0	
FLATHEAD LAKE	.5	
NOXON	.0	
PEND OREILLE LAKE	.5	
GRAND COULEE	1.7	
BROWNLEE	.1	
DWORSHAK	.7	
JOHN DAY	.1	
TOTAL	20.4	20.4
Forecast of Adjusted Residual Runoff Volume, MAF		36.1
Computed Initial Controlled Flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		210.0

Chart 1
Seasonal Precipitation Columbia River Basin October 1987 – March 1988 Percent of 1961–1985 Average

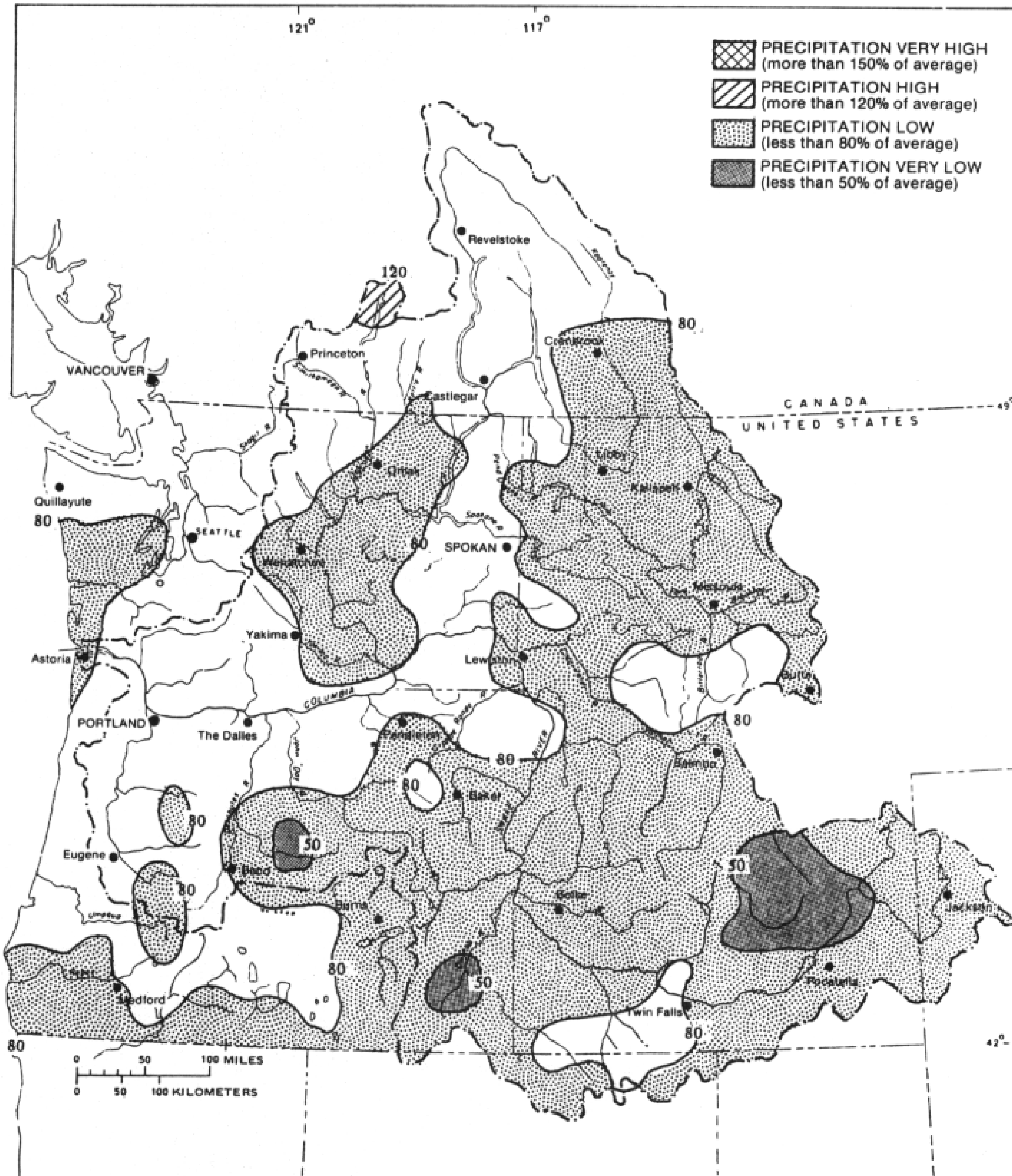


Chart 2
Columbia Basin Snowpack

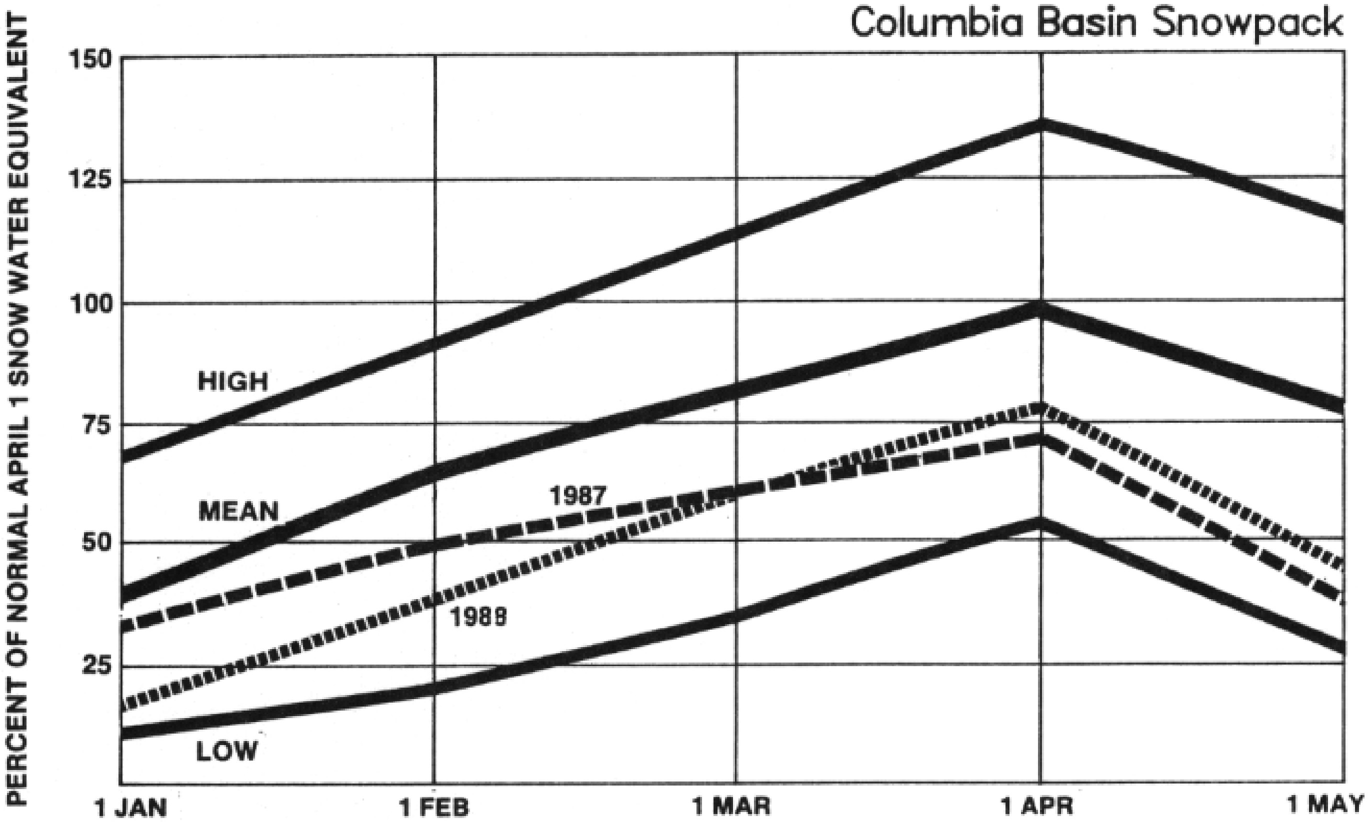
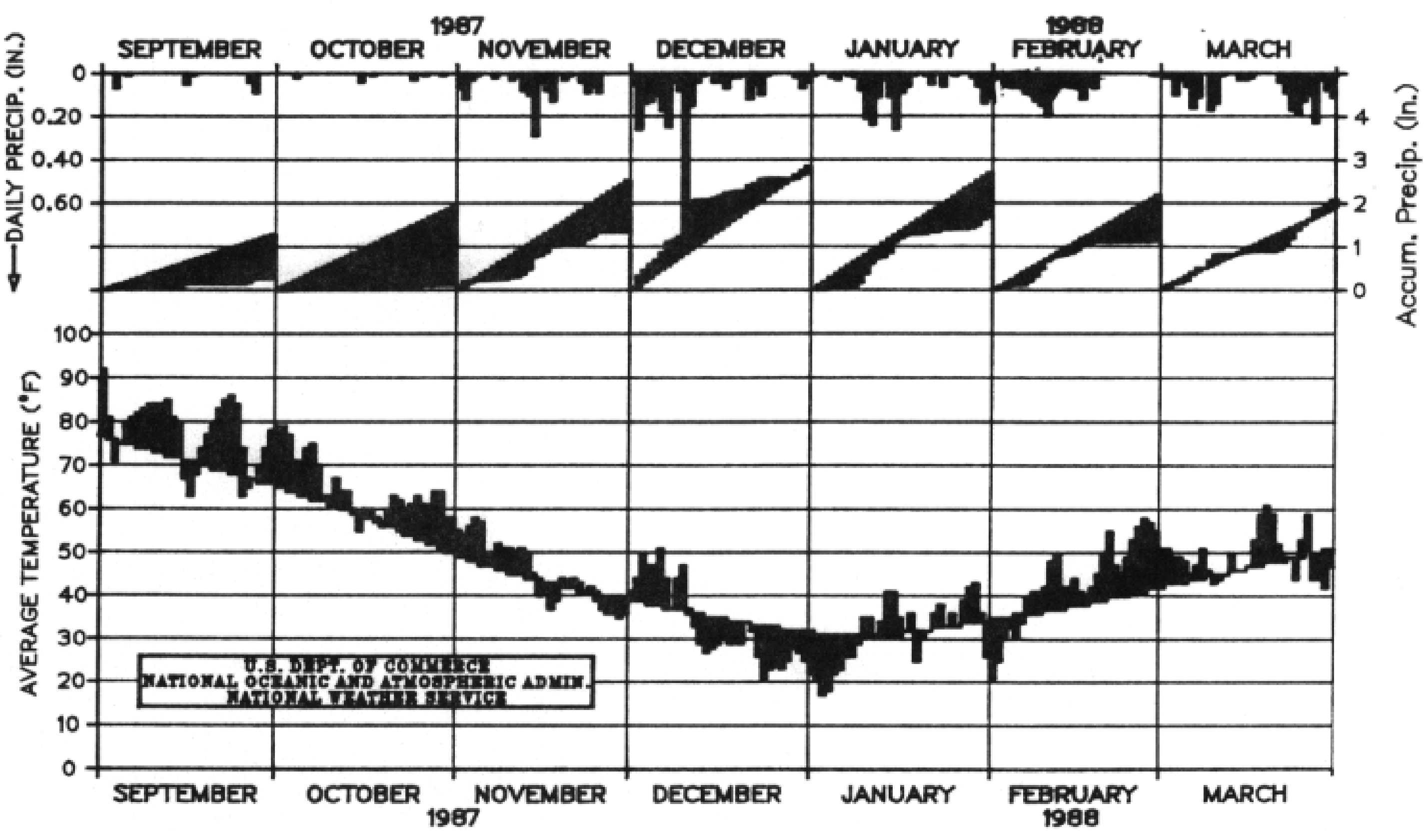
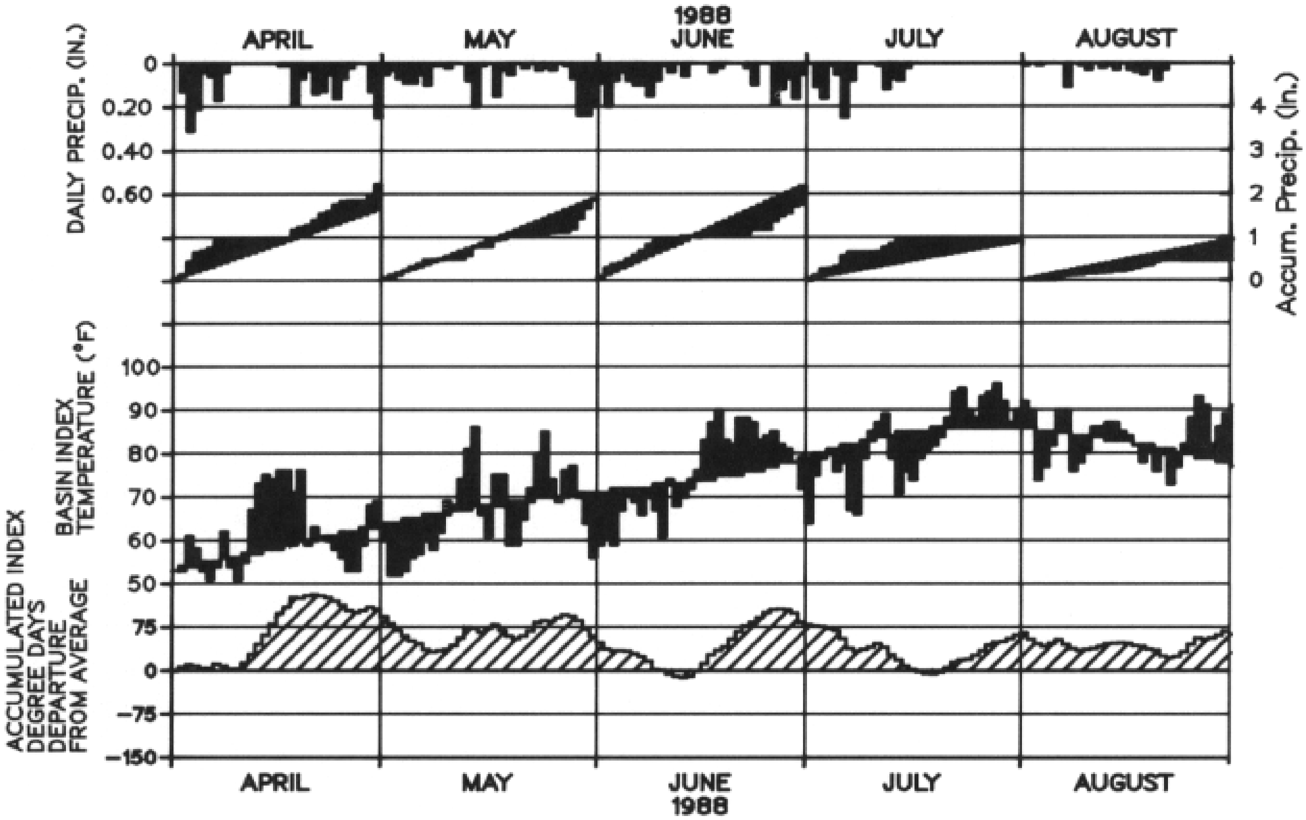
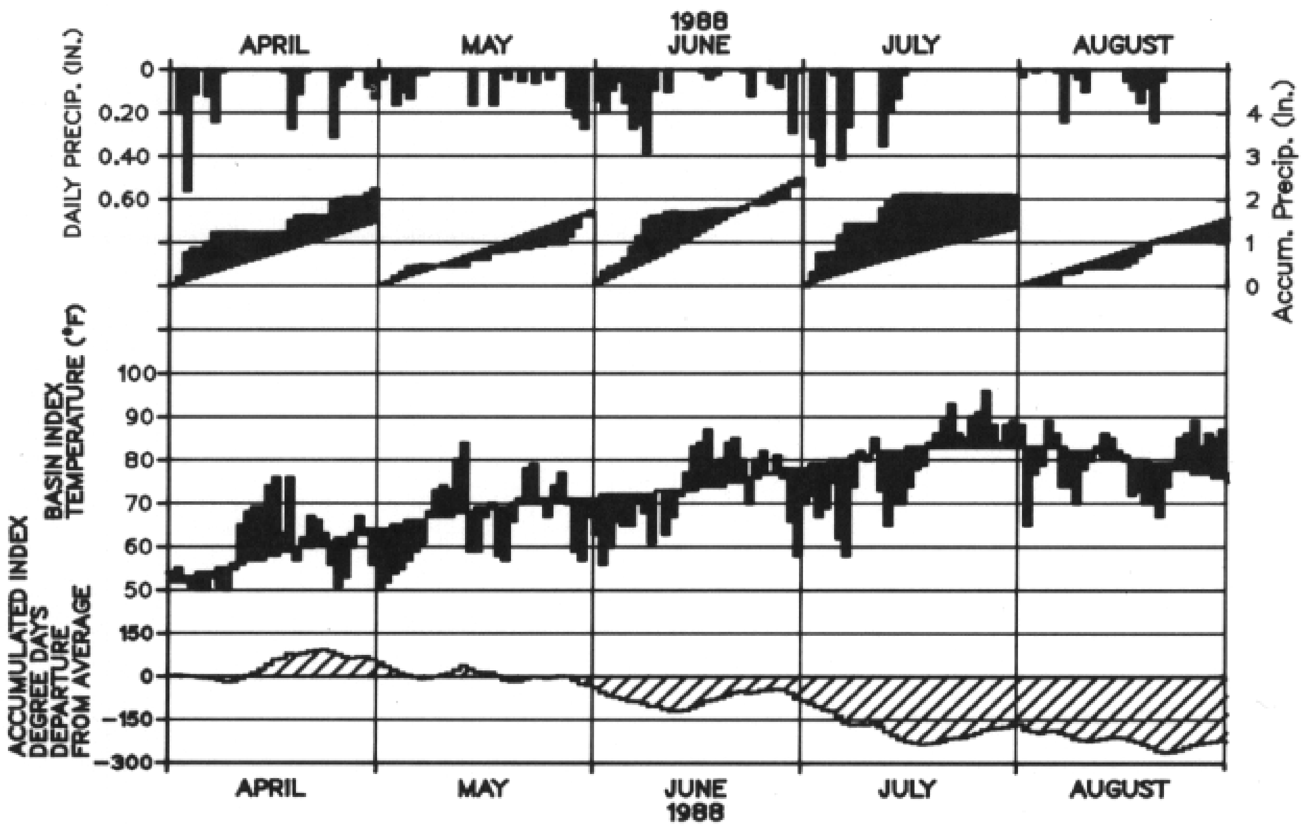


Chart 3
WINTER SEASON
Temperature and Precipitation Index 1987–1988
Columbia River Basin Above The Dalles, OR





SNOWMELT SEASON Chart 4
Temperature and Precipitation Index 1987–1988
Columbia River Basin Above The Dalles, OR



SNOWMELT SEASON Chart 5
Temperature and Precipitation Index 1987–1988
Columbia River Basin In Canada

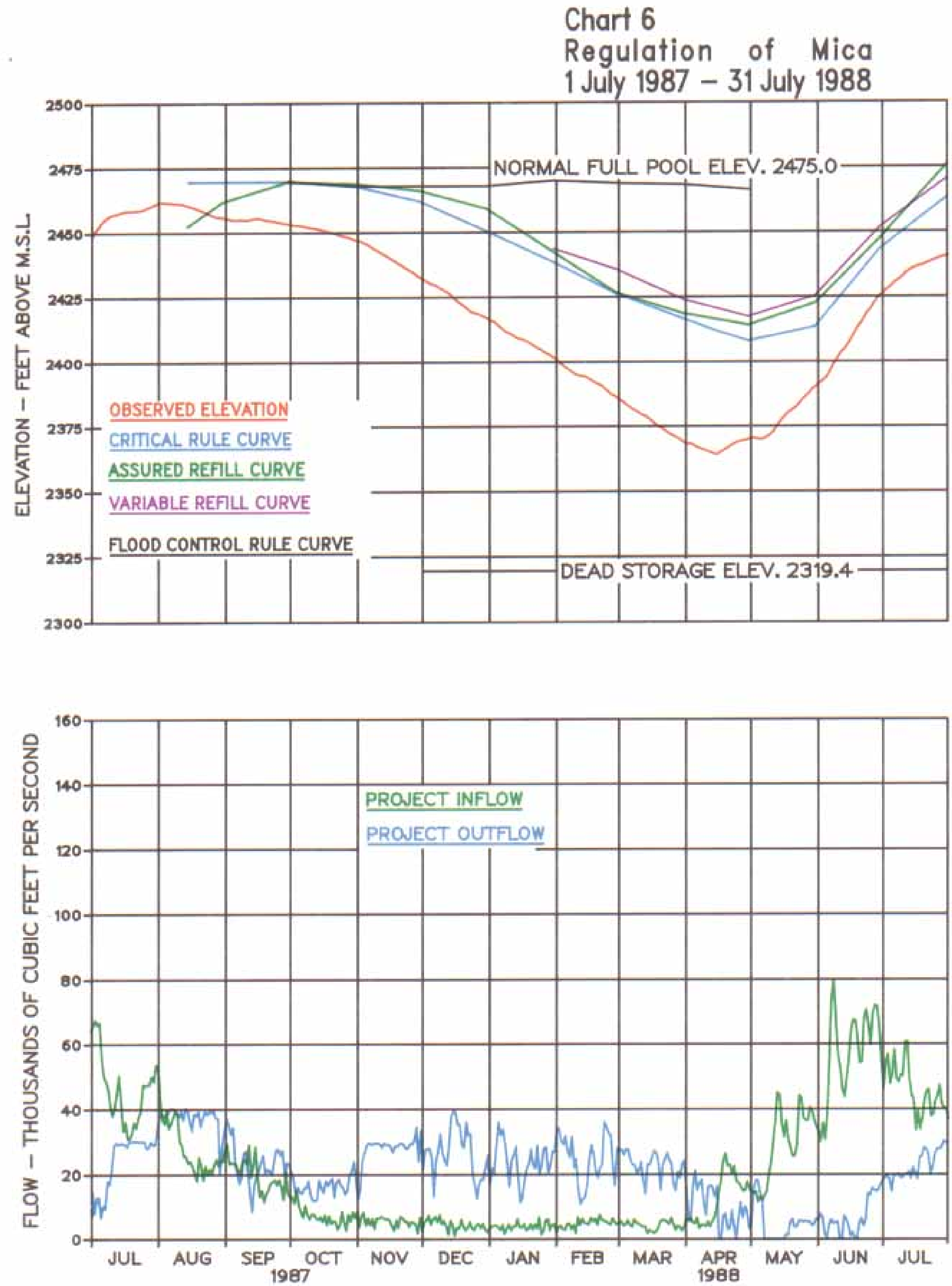
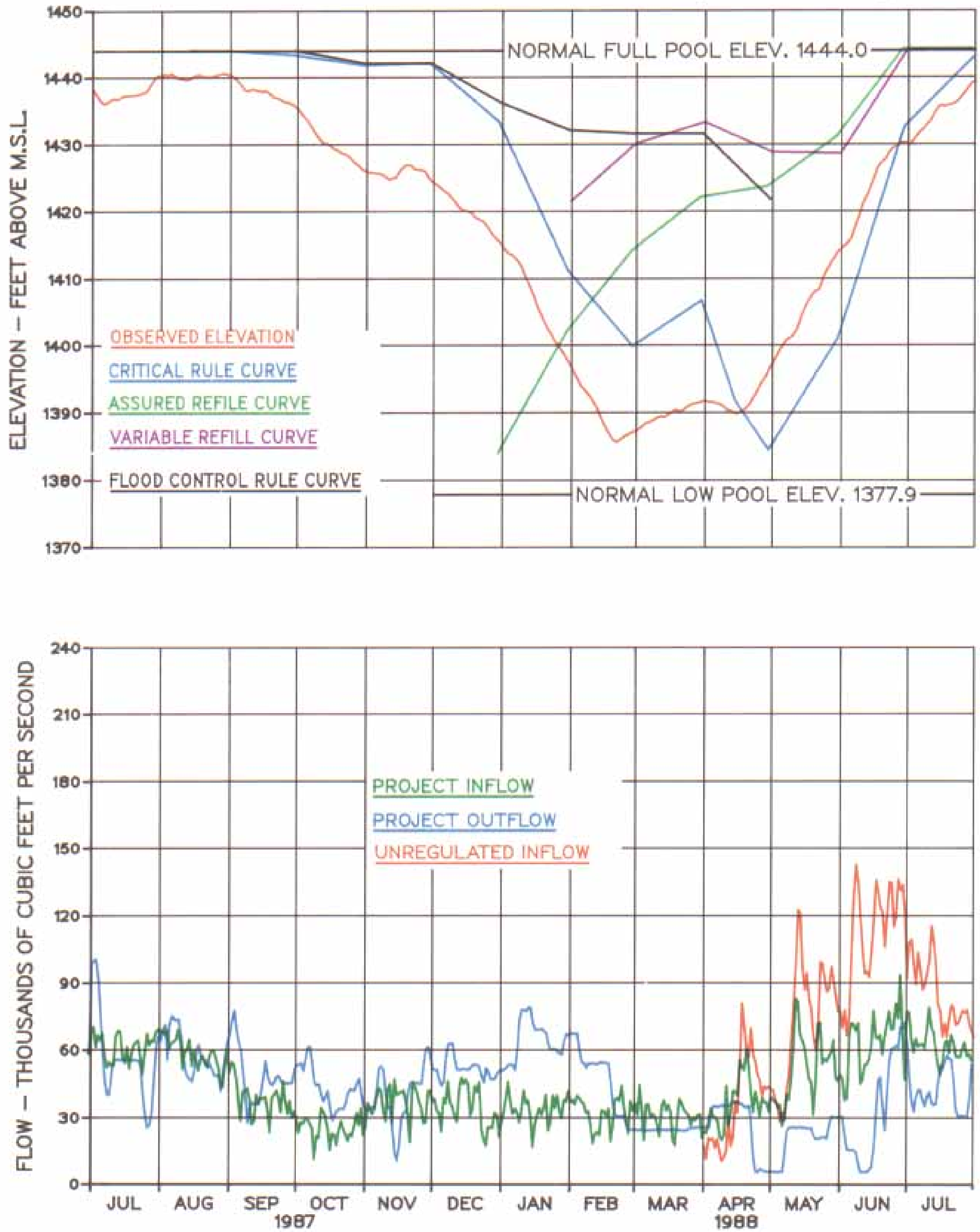


Chart 6
Regulation of Mica
1 July 1987 – 31 July 1988
NORMAL FULL POOL ELEV. 2475.0
DEAD STORAGE ELEV. 2319.4
OBSERVED ELEVATION
CRITICAL RULE CURVE
ASSURED REFILL CURVE
VARIABLE REFILL CURVE
FLOOD CONTROL RULE CURVE
ELEVATION – FEET ABOVE M.S.L.
2500
2475
2450
2425
2400
2375
2350
2325
2300
PROJECT INFLOW
PROJECT OUTFLOW
FLOW – THOUSANDS OF CUBIC FEET PER SECOND
160
140
120
100
80
60
40
20
0
JUL
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
JUN
JUL
1987
1988

Chart 7
Regulation of Arrow
1 July 1987 – 31 July 1988



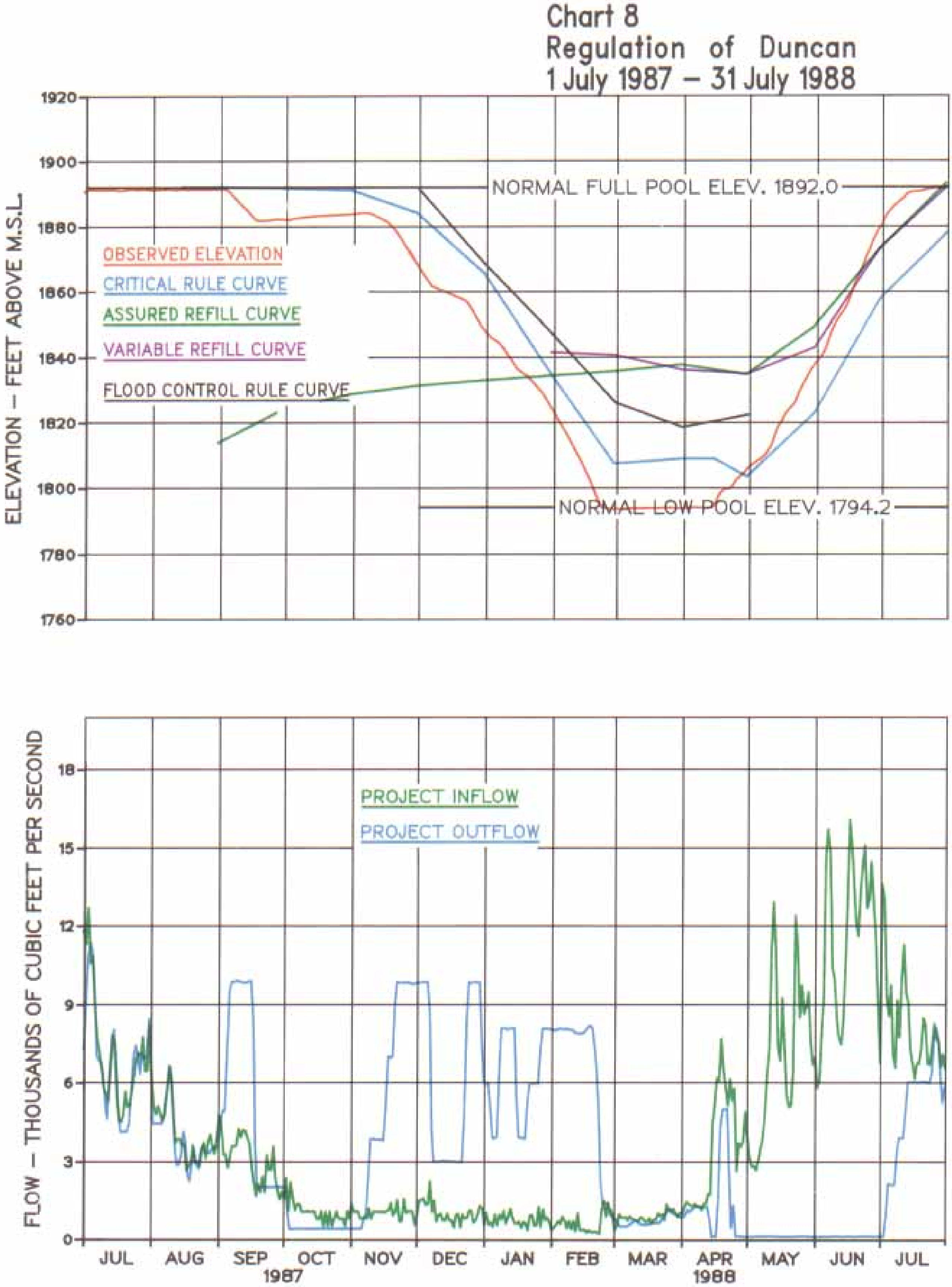


Chart 8
Regulation of Duncan
1 July 1987 – 31 July 1988
ELEVATION – FEET ABOVE M.S.L.
1920
1900
1880
1860
1840
1820
1800
1780
1760
NORMAL FULL POOL ELEV. 1892.0
OBSERVED ELEVATION
CRITICAL RULE CURVE
ASSURED REFILL CURVE
VARIABLE REFILL CURVE
FLOOD CONTROL RULE CURVE
NORMAL LOW POOL ELEV. 1794.2
FLOW – THOUSANDS OF CUBIC FEET PER SECOND
18
15
12
9
6
3
0
PROJECT INFLOW
PROJECT OUTFLOW
JUL
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
JUN
JUL
1987
1988

Chart 9
Regulation of Libby
1 July 1987 – 31 July 1988

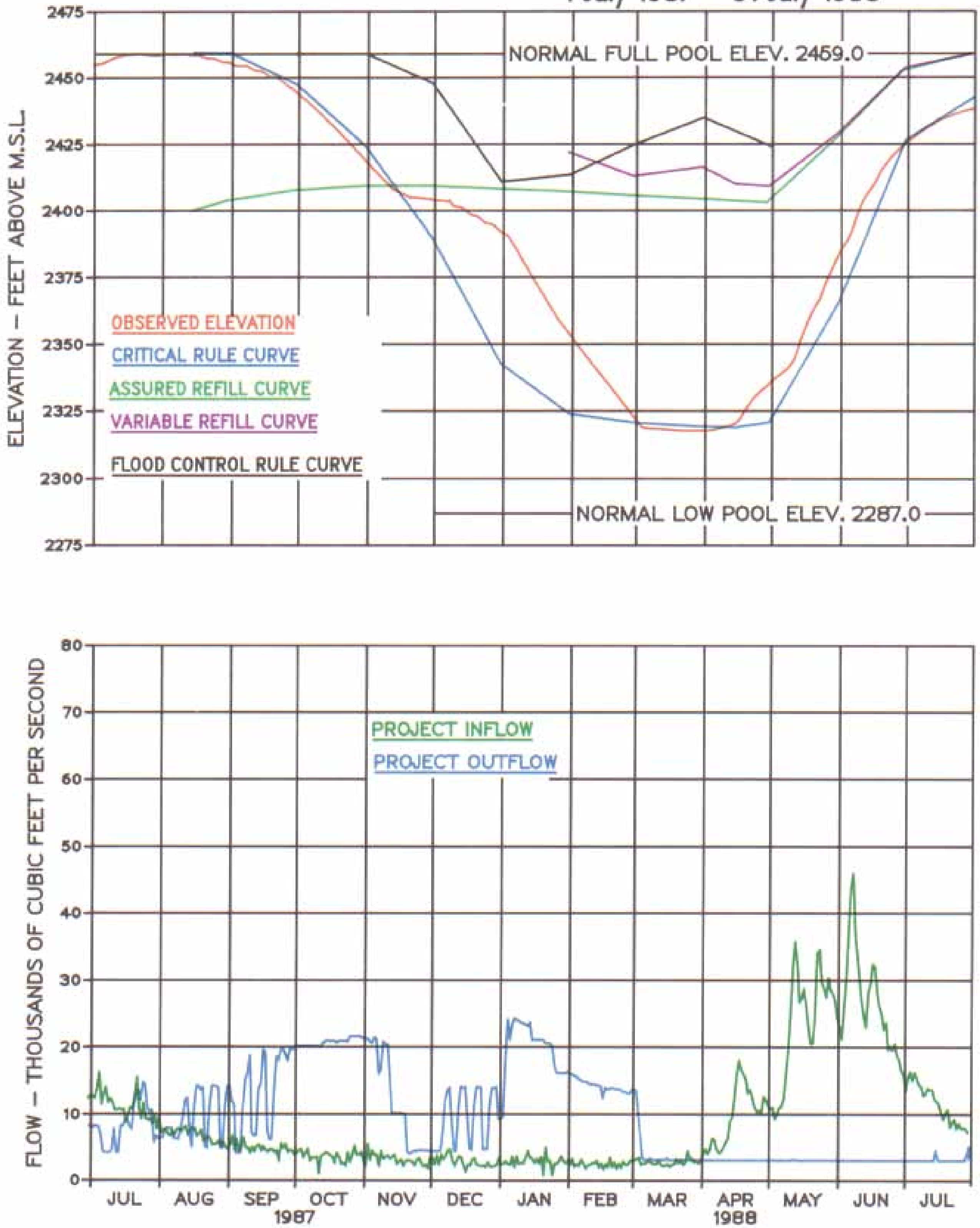


Chart 10
Regulation of Kootenay Lake
1 July 1987 – 31 July 1988

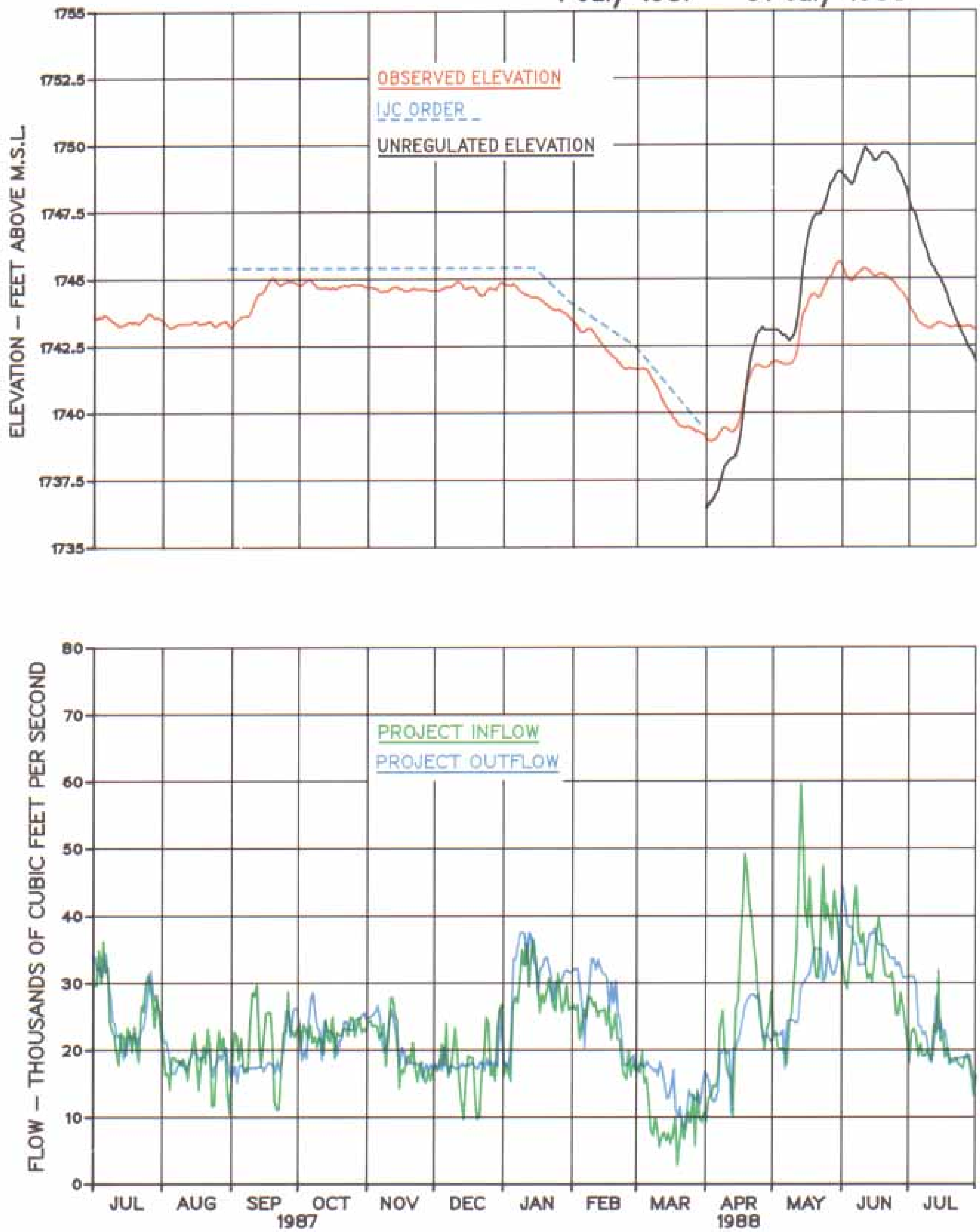


Chart 11
Columbia River at Birchbank
1 July 1987 – 31 July 1988

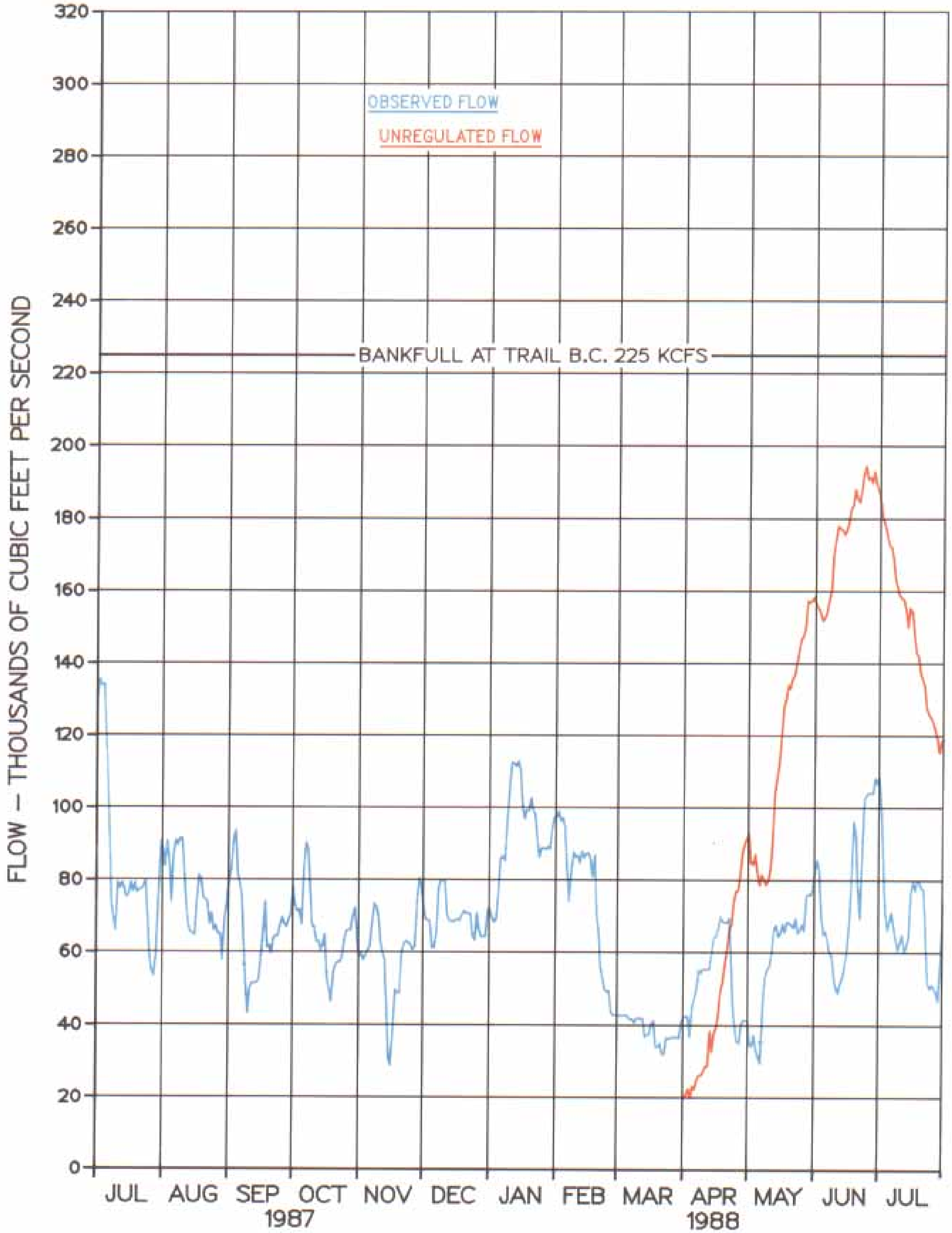


Chart 12
Regulation of Grand Coulee
1 July 1987 – 31 July 1988

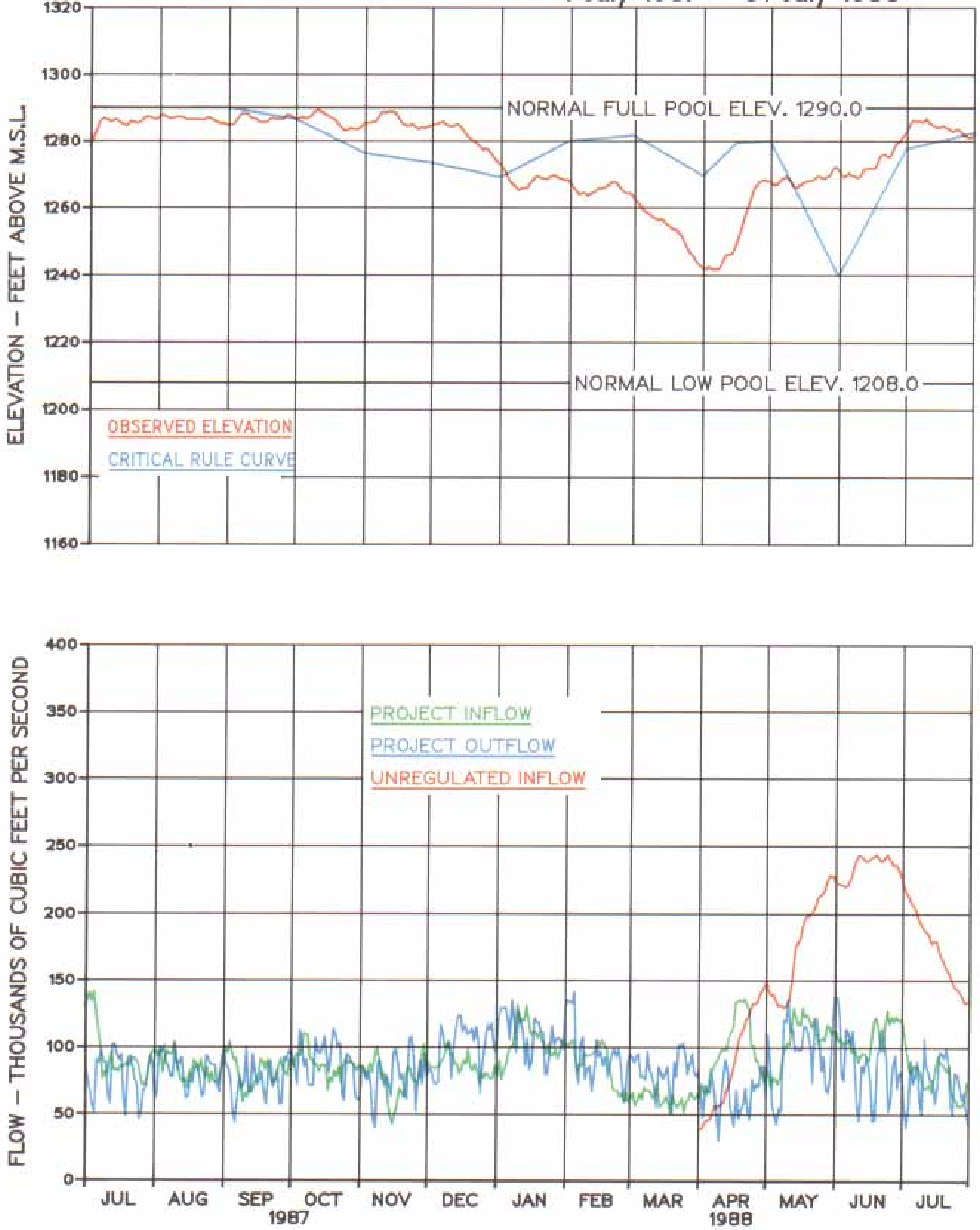


Chart 13
Columbia River at The Dalles
1 July 1987 – 31 July 1988

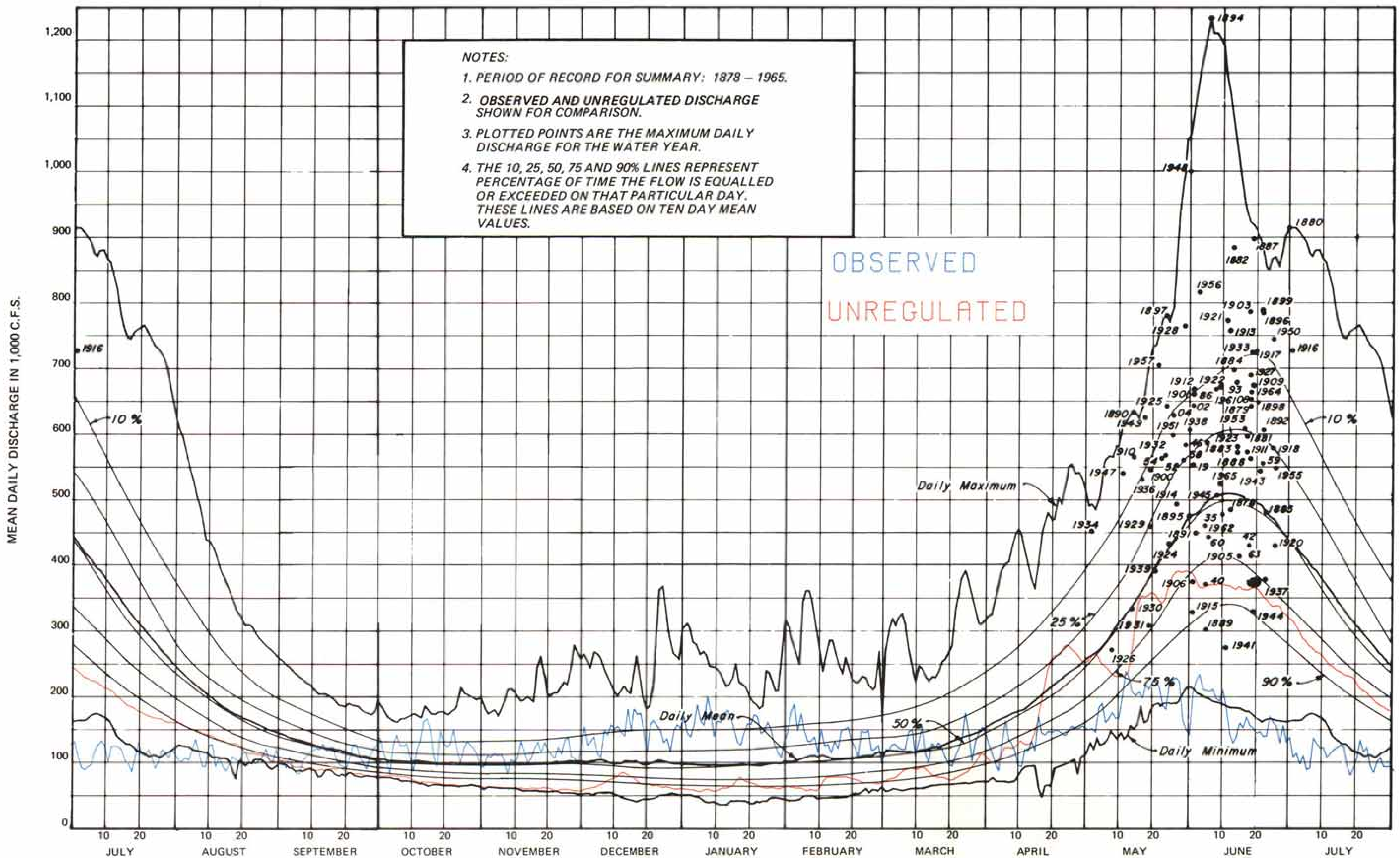


Chart 14
Columbia River at The Dalles
1 April 1988 – 31 July 1988

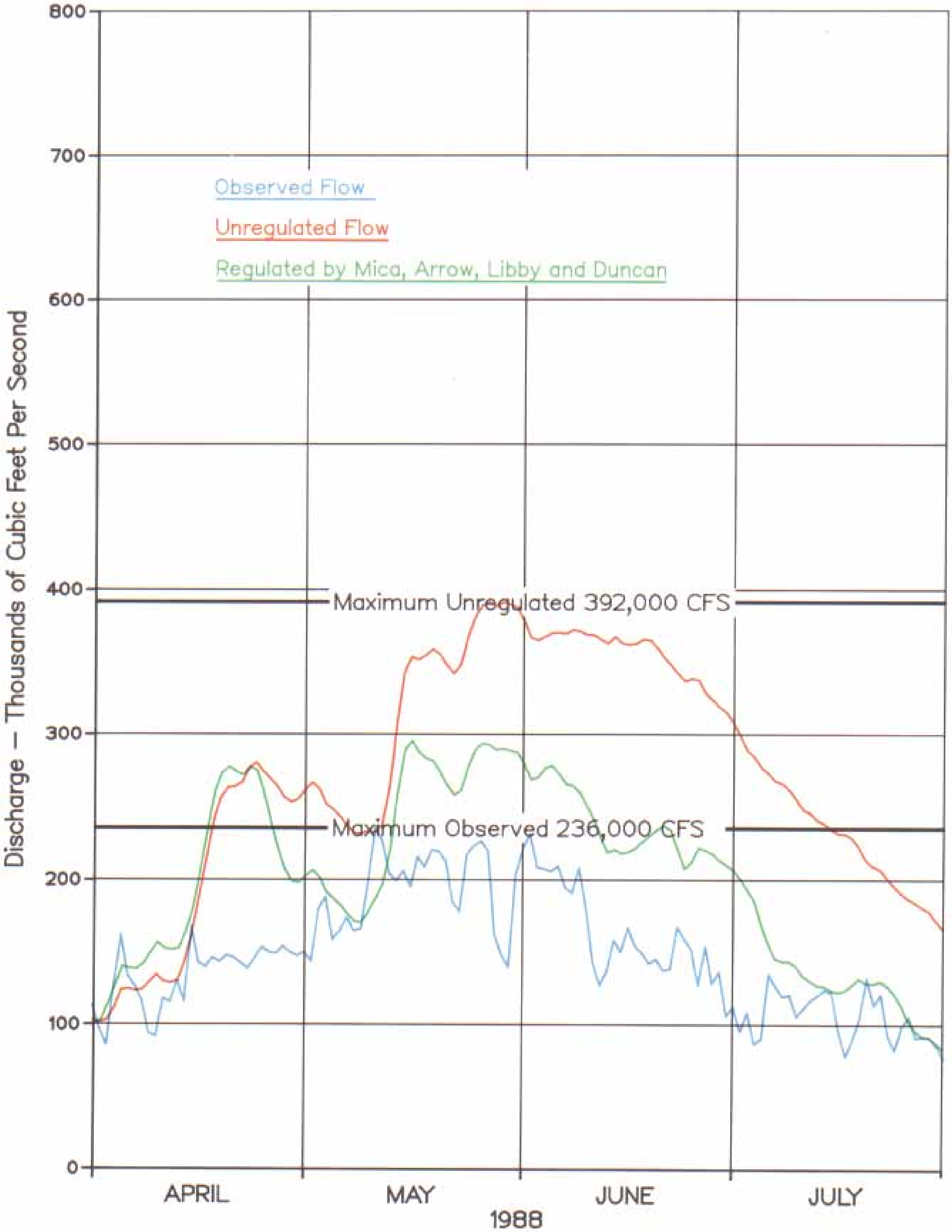


Chart 15
1988 Relative Filling
Arrow and Grand Coulee