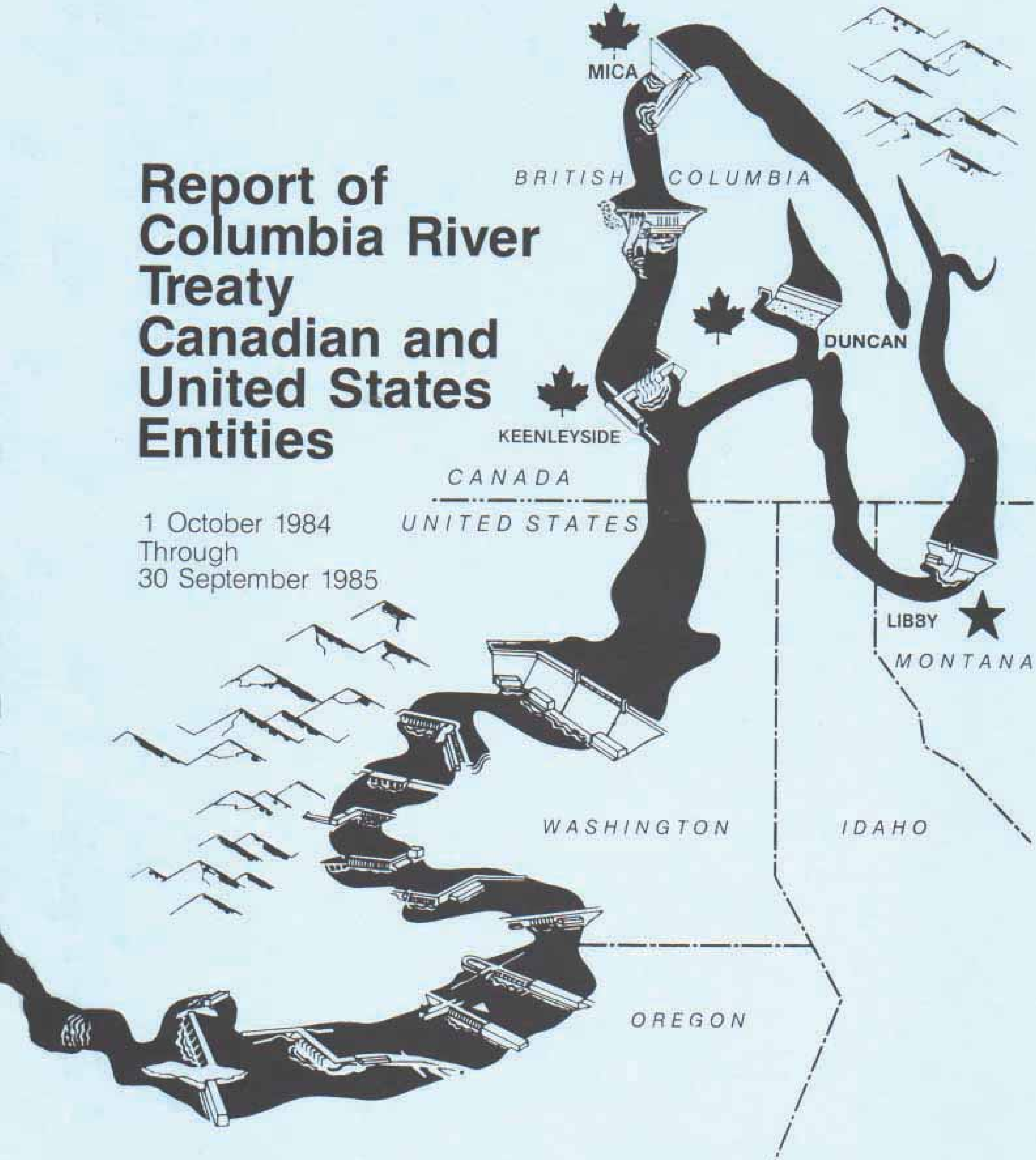
Report of Columbia River Treaty Canadian and United States Entities

1 October 1984
Through
30 September 1985



October 1985

ANNUAL REPORT OF THE

COLUMBIA RIVER TREATY

CANADIAN AND UNITED STATES ENTITIES

For the Period

1 October 1984

Through

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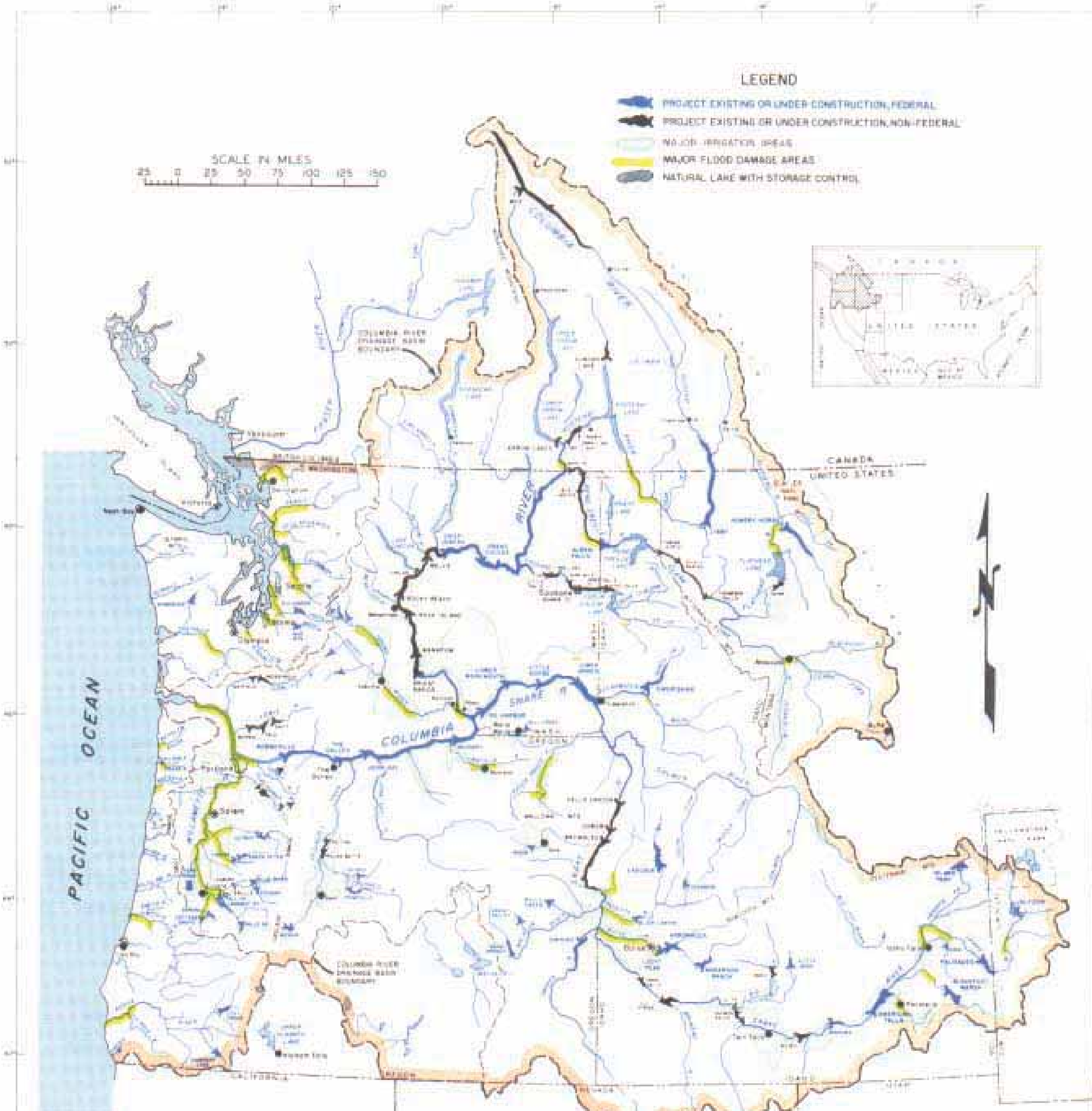
COLUMBIA RIVER AND COASTAL BASINS



1985 REPORT OF THE COLUMBIA RIVER TREATY ENTITIES

C O N T E N T S

C O N T E N T S (Continued)

1985 REPORT OF THE COLUMBIA RIVER TREATY ENTITIES

I. INTRODUCTION

This annual Columbia River Treaty Entity Report is for the 1985 Water Year, 1 October 1984 through 30 September 1985. 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 1984 through 31 July 1985. The power and flood control effects downstream in Canada and the United States are described. This report is the nineteenth 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 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. hydrolectric 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 28 November 1984 in Vancouver, British Columbia. The members of the two Entities during the period of this report were:

UNITED STATES ENTITY

Mr. Peter T. Johnson, Chairman
Administrator Bonneville Power Administration
Department of Energy
Portland, Oregon

Brigadier General George R. Robertson
Division Engineer,
North Pacific Division,
Army Corps of Engineers,
Portland, Oregon

CANADIAN ENTITY

Mr. Chester A. Johnson, Chairman
Chairman, British Columbia Hydro and Power Authority
Vancouver, B.C.

Mr. Chester A. Johnson succeeded Mr. Robert W. Bonner as Chairman of B.C. Hydro and Power Authority on 11 January 1985. Mr. Bonner had been Chairman since 1 February 1976.

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 service as coordinators or focal points on Treaty matters within their organizations. These are:

UNITED STATES ENTITY COORDINATORS

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

Herbert H. Kennon, Coordinator
Chief, Engineering Division
North Pacific Division
Army Corps of Engineers
Portland, Oregon

John M. Hyde, Secretary
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
Gordon G. Green, ACE	William N. Tivy, BCH
John M. Hyde, BPA	Kenneth R. Spafford, BCH

Mr. Griffin succeeded Mr. Charles E. Cancilla as BPA Co-Chairman of the U.S. Section of the Operating Committee on 14 September 1985. Mr. Cancilla, who left Bonneville Power Administration after a long career with Treaty related activities, had replaced Mr. Lawrence A. Dean, who retired from BPA, as Co-Chairman on 4 January 1985.

There were six meetings of the Operating Committee during the year including one joint meeting with the Entity Hydrometeorological Committee. The dates, places and number of persons attending those meetings were:

4 October 1984 at Vancouver, B.C., with 17 attendees;
5 December 1984 at Portland, Oregon, with 19 attendees;
20 February 1985 at Vancouver, B.C., with 12 attendees;
2 May 1985 at Portland, Oregon, with 22 attendees, including Hydromet Committee;
9 July 1985 at Vancouver, B.C., with 15 attendees; and
10 September 1985 at Portland, Oregon with 14 attendees.

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.

The Committee prepared the Entity agreements listed in the following section and developed the Detailed Operating Plan for the 1985-86 operating year. The Entities were not able to agree on several issues which affect the development of the Assured Operating Plan and the Determination of Downstream Power Benefits. The U.S. Entity disputes the position shared by the Canadian Entity and the Permanent Engineering Board that updated streamflow records must be used in the downstream benefit computations and that the implementation of the Northwest Power Planning Council's Water Budget minimum flow requirements in the Assured Operating Plan contradicts Treaty requirements for optimum operation for power and flood control benefits. In order to obtain sufficient information for resolution of the dispute, the Operating Committee agreed to prepare the following two studies:

1. Traditional Assured Operating Plan and Determination of Downstream Power Benefits. This study is similar to last year's study and does not contain updated streamflow records in the downstream benefit computations.

2. U.S. Position Assured Operating Plan and Determination of Downstream Power Benefits. This study includes the Water Budget minimum flows, updated streamflow records, and surplus firm energy shaping.

Results will be made available to the Permanent Engineering Board upon completion of the studies. The Entities will continue to seek a resolution of this dispute and agreement on an Assured Operating Plan and Determination of Downstream Power Benefits at the earliest possible date.

ENTITY HYDROMETEORLOGICAL 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
Douglas D. Speers, ACE, Co-Chairman	Ulrich Sporns, BCH, Chairman
Roger G. Hearn, BPA, Co-Chairman	John R. Gordon, BCH, Member

There were two meetings of the Hydrometeorological Committee during the year, on 9 November 1984 in Vancouver B.C. and the joint meeting with the Entity Operating Committee on 2 May 1985 in Portland, Oregon. Nine people were in attendance at the first meeting and 22 at the second meeting. Discussion topics at both meetings included hydromet data exchange, water supply and streamflow forecasting, snow monitoring, new developments in hydromet facilities, and the Committee's Hydrometeorological Documents report.

The Committee submitted an interim version of the Hydrometeorological Documents Report to the Permanent Engineering Board in November 1984. This was reviewed by the Board's Engineering Committee and several comments were conveyed to the Hydrometeorological Committee in March 1985. Based upon these comments, the Committee worked on revisions to the report along with new maps of the Treaty and Support Facility station locations. A revised version of the report will be issued before the end of the 1985.

Further advancement in the hydromet data exchange occurred during the year, with the addition of new satellite data collection platforms (DCP) in Canada, and the improvement of hardware and software in the United States at the CROHMS (Columbia River Operational Hydromet Management System) central computer facility. The Corps of Engineers procured satellite downlink equipment which will be installed in Portland in late 1985. This will enable both Canadian and United States satellite stations to be reported directly to the CROHMS central computer rather than having it relayed to Portland via other communication channels and through other agencies.

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

Lloyd A. Duscha, Chairman,
Washington, D.C.
J. Emerson Harper, Member
Washington, D.C.

Alex Shwaiko, Alternate
Washington, D.C.
Thomas L. Weaver, Alternate
Golden, Colorado
S. A. Zanganeh, Secretary
Washington, D.C.

CANADIAN SECTION

G. M. MacNabb Chairman
Ottawa, Ontario
B. E. Marr, Member
Victoria, B.C.

H. M. Hunt, Alternate
Victoria, B.C.
E. M. Clark, Alternate & Secretary

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 benefit computations, hydrometeorological documents, 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 28 November 1984 in Vancouver, B.C. Differences between the two Entities and the PEB in how to prepare AOP's and determine downstream power benefits for the future did surface during discussions at this meeting and subsequently in correspondence.

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, Chairman
Washington, D.C.
Gary L. Fuqua, Member
Portland, Oregon
Larry Larson, Alternate
Washington, D.C.

CANADIAN SECTION

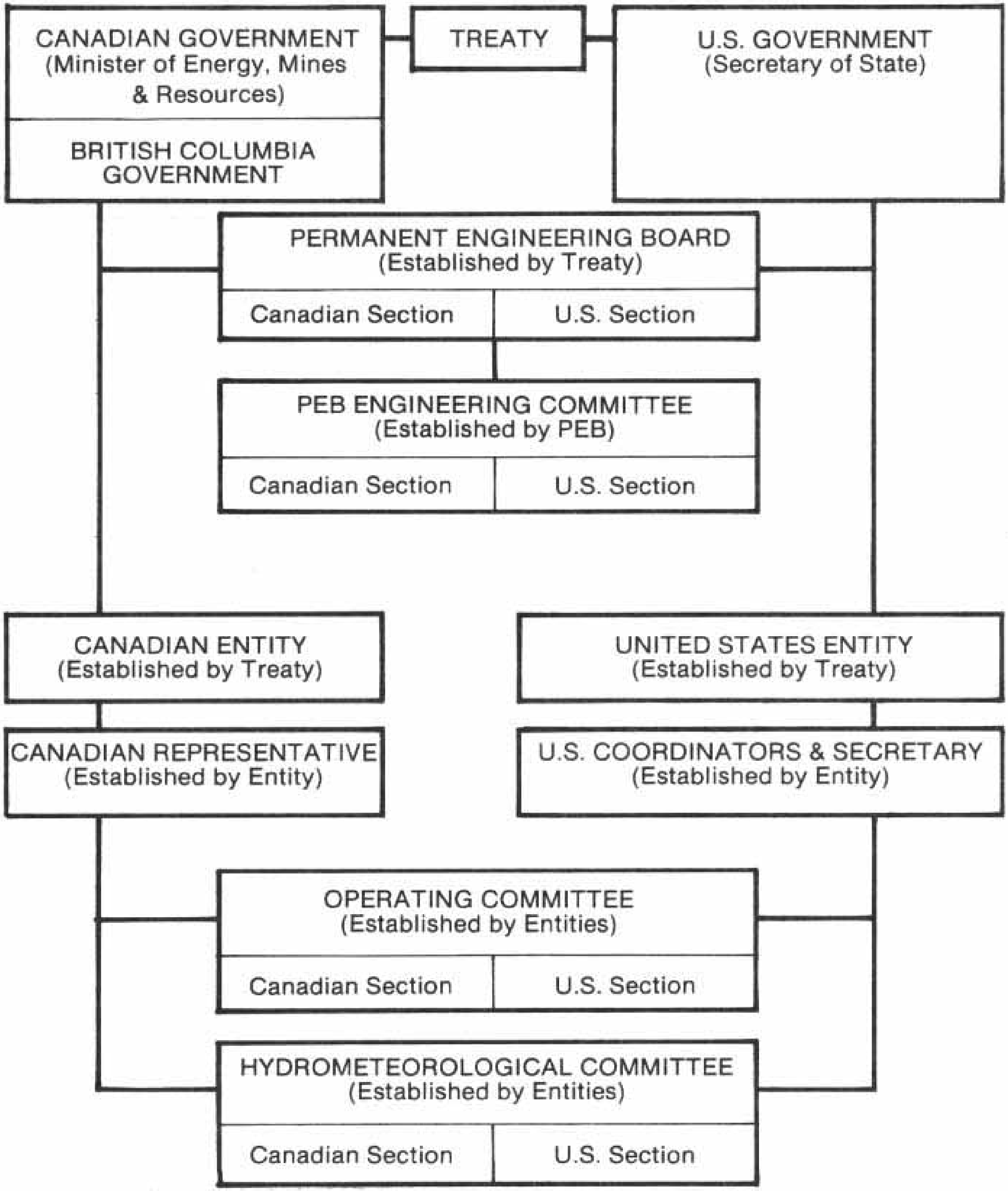
Ron J. White, Chairman
Vancouver, B.C.
David B. Tanner, Member
Victoria, B.C.
R. O. "Neil" Lyons, Alternate
Vancouver, B.C.

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 Annex A.

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 done 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 1984 through July 1985.

ASSURED OPERATING PLAN

The Assured Operating Plan (AOP) dated September 1979 established Operating Rule Curves for Duncan, Arrow and Mica during the 1984-85 operating year. The Operating Rule Curves provided guidelines for refill levels as well as drawdown 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. The AOP for operating year 1990-1991 was started during the year covered by this report but was not completed because of differences between the Entities as to how this plan should be prepared.

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 1983-84 and 1984-85 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 5.5 average megawatts of energy during the period 1 August 1984 through 31 March 1985, and 3.5 average megawatts of energy during the period from 1 April through 31 July 1985. 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 1984-85 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 September

1984. The DOP established criteria for determining the Operating Rule Curves for use in actual operations. Except for minor changes at Arrow, the DOP used the AOP critical rule curves for Canadian projects. The Canadian Entity agreed to raise the Arrow first year February and April critical rule curve to improve the hydroregulation in the 1984-85 Pacific Northwest Coordination Agreement operating plans. The Variable Refill Curves and flood control requirements subsequent to 1 January 1985 were determined on the basis of seasonal volume runoff forecasts during actual operation. The regulation of the Canadian storage was conducted by the Operating Committee on a weekly basis throughout this period because flood control operation did not require daily regulation. During the period of this report the DOP for operating year 1985-86 was prepared.

ENTITY AGREEMENTS

During the period covered by this report two new arrangements were officially approved by the Entities. The following tabulation indicates the date each of these were signed or approved and gives a description of the official title of the agreement:

Date Agreement Signed by Entities	Description
28 November 1984	Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 1989-90, dated October 1984.
28 November 1984	Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1984 through 31 July 1985, dated September 1984.

LONG TERM NON-TREATY STORAGE CONTRACT

An Entity agreement was completed on 9 April 1984 indicating their approval of a new long term contract between B.C. Hydro and BPA (BPA contract no. DE-MS79-84BP90946) relating to the initial filling of Revelstoke and the coordinated use of some of the Canadian Columbia River non-Treaty storage, and Mica and Arrow reservoir refill enhancement. The contract resolved a dispute concerning the initial filling of Revelstoke and Seven Mile reservoirs in Canada, and provides mutual benefits through the storage of water in both non-Treaty and Treaty storage space.

The Entity Agreement also approves a companion contract (BPA contract no. DE-MS79-84BP90945) between BPA and the mid-Columbia purchasers who are owners or purchasers of the output of the five mid-Columbia dams. This contract allows the mid-Columbia purchasers to participate in actions that occur under the contract between BPA and BCH.

This 9 April 1984 Entity agreement states in part: "The United States and Canadian Entities have reviewed these agreements and are satisfied that there are mutual benefits to be derived from these agreements and that these benefits can be achieved without adversely affecting: (1) the operation of Treaty space in accordance with the Columbia River Treaty; and (2) the performance of obligations pursuant to the Canadian Entitlement Purchase Agreement. The Columbia River Treaty Operating Committee is hereby instructed to insure that any operation pursuant to these agreements does not adversely affect operation of Treaty space pursuant to the Columbia River Treaty."

These storage contracts are expected to be in force for ten years from the effective date of 10 October 1983 and the key provisions are:

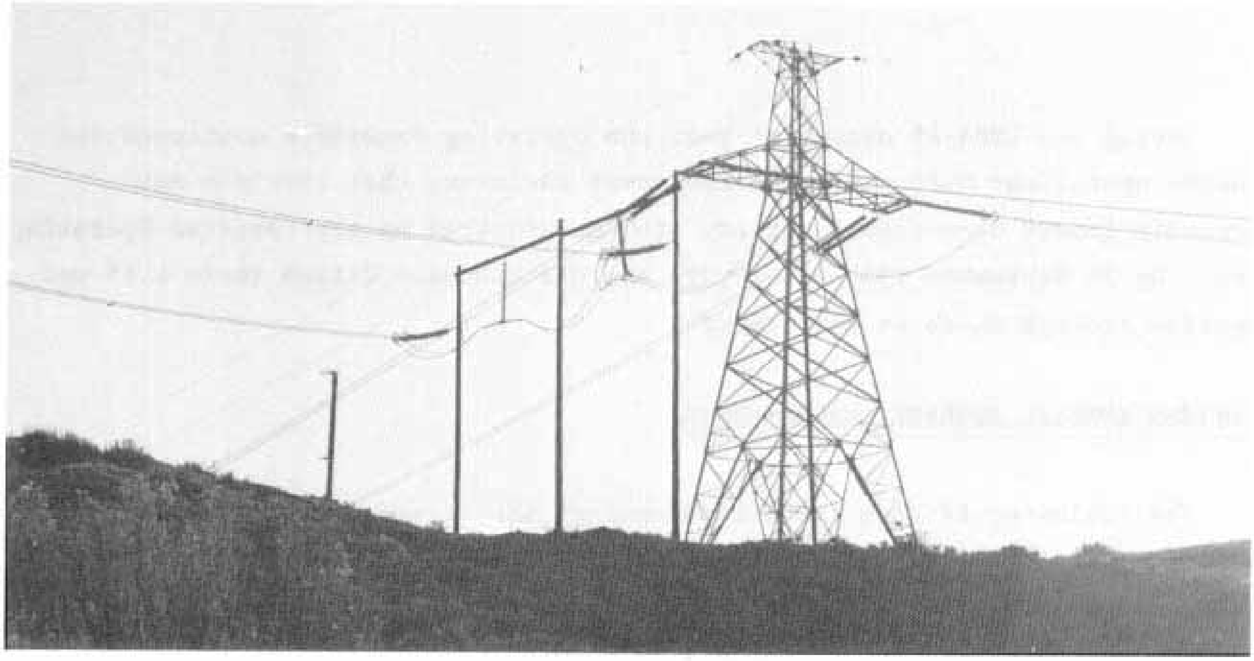
1. Each party will store 1.15 million acre-feet (maf) into inactive reservoir storage space in Revelstoke by 30 September 1985.
2. BCH shall declare 2.0 maf of vacant storage space available as active storage space for use by BPA and BCH.
3. BCH may make additional space available from time to time as recallable storage space, one-half being available to each party.

During the 1984-85 operating year 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. By 30 September 1985 B.C. Hydro and BPA had each filled their 1.15 maf inactive storage space at Revelstoke.

PREVIOUS SPECIAL STORAGE ARRANGEMENTS

The following listing summarizes some of the arrangements that have made possible additional uses of Treaty and non-Treaty reservoirs in the United States and Canada since 1977. These arrangements are in addition to general storage and load-factoring agreements which enabled BPA and B.C. Hydro to accept energy from the other for storage in non-Treaty reservoir space.

Year	Arrangement
1977	Emergency draft of Canadian Treaty storage.
1977	Delivery of B.C. Hydro energy to BPA to raise the summer level of Arrow Lakes.
1978	Agreement to enhance refilling Mica reservoir.
1980	Storage of energy in Mica to enhance its refill and delivery to Canada of energy from the release of 500,000 acre-feet from Mica.
1980	Storage of an additional two feet of water in Arrow Lakes.
1981	Storage of an additional two feet of water in Arrow Lakes.
1983	Two short term agreements providing for use of two feet of non-treaty storage at Arrow and up to four feet of non-treaty storage at Mica.
1984	Long term (ten year) non-treaty agreement relating to the initial filling of Canadian non-treaty reservoirs use of non-treaty storage, and Mica and Arrow refill enforcement.



D-C INTERTIE LINE AND CONVERTER STATION. The direct current line, which is one of the three powerlines known collectively as the Pacific Northwest- Southwest Intertie, stretches 846 miles from the Celilo Converter Station near The Dalles, Oregon, to the Sylmar Converter Station near Los Angeles. On 1 February 1985 the d-c line voltage was raised from 800 kv to 1000 kv by the completion of an additional converter group at each station. Total d-c line capacity was raised from 1560 mw to 1960 mw. The sale of the Canadian entitlement to the Treaty power benefits was one of the major justifications for the original construction of the intertie.

IV. WEATHER AND STREAMFLOW

WEATHER

Chart 1 is a geographical illustration of the seasonal precipitation in percent of normal for the 1 October 1984 through 31 March 1985 period in the Columbia River Basin. Chart 2 shows an index of the accumulated snowpack in the Columbia Basin above The Dalles in percent of normal for the 1 January through 1 May 1985 period. Indices of temperature and precipitation in the Columbia Basin are shown on charts 3, 4, and 5 for the 1 September 1984 to 31 August 1985 period. The following paragraphs describe significant weather factors from 1 August 1984 to 30 September 1985. In this report temperatures are given in degrees Fahrenheit.

Weather over the Columbia Basin in the 1984-85 year was highly variable in nearly all aspects. The fall months of September and October 1984 saw near normal precipitation and below normal temperatures that were broken by three short warm spells. Winter weather arrived on 2 November accompanied by a deep low pressure storm system. Precipitation was persistent throughout the month so that by mid-month there had been only three days in which no precipitation was observed anywhere in the basin. Monthly totals for most subbasins were near 135 percent of normal. Below normal precipitation occurred only in the Clark Fork and Flathead Basins. Precipitation in southern British Columbia was above average with some stations receiving twice their normal amount. By the end of November the mountain snowpacks in most basins were above to well above average.

A high pressure system that settled on the coast on 2 December brought a dramatic change in both temperature and precipitation patterns. Temperatures dropped dramatically. Only a few days near the 10th, 15th and 20th were near normal. Precipitation for the month also dropped dramatically with subbasins totals between 70 and 80 percent of normal. These below normal temperatures continued through January 1985, except in British Columbia which warmed to slightly above normal. Precipitation during January, however, decreased to record lows with some stations receiving their lowest-ever January precipitation in 70 to 100 years. Monthly totals for January were 16 percent of normal for the basin above Grand Coulee, 19 percent for the basin above Ice Harbor, and 16 percent for the basin above The Dalles.

The first two weeks of February were a continuation of the cold January weather although precipitation was near normal. The latter half of the month, however, saw a return of the dry conditions but this time with normal temperatures. Basin-wide precipitation averaged less than 80 percent of normal.

March saw a majority of the drainage, including British Columbia, continue in mild, dry conditions with warm temperatures starting to melt the valley snowpack. Meanwhile storms from northern California were entering the southern portion of the Snake River Basin. This resulted in below normal temperatures and normal to much-above normal precipitation, some as high as 130 percent of the monthly average.

On April 1 there was another shift in weather patterns. The first half of the month was warmer than normal, with normal to below-normal precipitation. The latter half of the month was wet and cold. Exceptions were the northern Columbia Basin in British Columbia and the northern Washington Cascades which were 120 to 150 percent of normal. These weather patterns continued to mid-May when a 10-day warm spell, with temperatures 10 to 12 degrees above normal, produced some significant snowmelt. This was followed by a cool, wet period which lasted until 10 June. The remainder of June and all of July 1985 were 5 to 8 degrees above normal and virtually without precipitation. Precipitation in the Columbia Basin above The Dalles during the January through July 1985 period was only 63 percent of normal, and for several stations record low amounts of precipitation were observed.

The first three weeks of August were relatively cool, 7 degrees below normal, and the preliminary precipitation index averaged well above normal. However, the final index for August indicated basin-wide precipitation was below average. September 1985 was wet and cool, and was the first month since November 1984 with above average precipitation.

The final precipitation index figure for the Columbia Basin above The Dalles each month differs from the preliminary precipitation index figure. The preliminary index is computed daily based on 16 usually 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. There is usually some slight difference between the preliminary and the final monthly precipitation figures. For August 1985 the difference was unusually large. In August the precipitation at the preliminary index stations must have been heavy local showers that were not representative of the basin as a whole. The following tabulation shows the 20-year average (1961-1980) monthly precipitation in the Columbia Basin above The Dalles as compared to the final and the preliminary (prelim) indices for water year 1985 (WY-85).

Month	20-Year Average (in.)	WY-85 Indices Final (%)	WY-85 Indices Prelim (%)	Month	20-Year Average (in.)	WY-85 Indices Final (%)	WY-85 Indices Prelim (%)
Oct '84	1.76	115	91	Apr '85	1.61	83	92
Nov '84	2.71	140	127	May '85	1.75	96	83
Dec '84	3.29	82	71	Jun '85	1.84	84	66
Jan '85	3.33	16	13	Jul '85	0.96	52	24
Feb '85	2.15	82	66	Aug '85	1.29	90	159
Mar '85	1.91	70	62	Sep '85	1.41	206	204

STREAMFLOW

The observed inflow and outflow hydrographs for the period 1 July 1984 to 31 July 1985 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 two unregulated flows at The Dalles during the April through July 1985 period including one that would have occurred if regulated only by the Treaty reservoirs. The following paragraphs describe significant streamflow events from the summer of 1984 through September 1985.

Streamflow during the August through November 1984 period was greater than normal in the southern half of the Columbia River Basin, while there was near normal streamflow across the northern portions. The heavy November precipitation had little direct effect on the fall runoff. In December almost all the southern basins fell to near normal flows, while the northern basins fell to below average. Discharges in the upper Snake, upper Columbia, Clark Fork and Kootenay Basins returned to near normal in January, whereas most central and southern basins fell to below average.

During February and March 1985, the final two months of the winter 1984-85 snow accumulation season, the magnitude of streamflows remained below normal across all of the Columbia Basin except for a small region in the upper Snake, Salmon and eastern Oregon basins that remained near normal. Warm temperatures and average to above-average precipitation in April returned the upper Columbia, Kootenai and Clark Fork Basin streamflows to near normal, and increased most of the remaining central and southern basin streamflows to above average. This trend was short-lived, as May saw a return to normal flows at nearly all stations across the Columbia basin. The situation deteriorated throughout June and July 1985 with flows dropping to below normal in all but the western Oregon and western Washington basins.

The maximum mean monthly modified streamflow for the Columbia River at Grand Coulee occurred in May 1985 and was 104 percent of the long-term average. The maximum for the Columbia River at The Dalles also occurred during May and was 102 percent of the long-term average. Maximum observed mean daily inflows during the 1984-85 operating year were 75,820 cfs at Mica on 25 May, 112,390 cfs at Arrow on 24 May, 18,200 cfs at Duncan on 24 May and 56,100 cfs at Libby on 25 May. The maximum observed mean daily flow in the Columbia River at The Dalles was 279,000 cfs on 6 May and the peak unregulated flow was 550,000 cfs on 27 May. The early peak observed flows were the result of favorable power marketing conditions and not from early snowmelt conditions.

The 1984-85 monthly modified streamflows and the average monthly flows for the 1926-1985 period are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These modified flows have been corrected for storage in lakes and reservoirs to exclude the effects of regulation, and are adjusted to the 1980 level of development for irrigation.

	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Modified Flow 1984-1985	Average 1926-1985	Modified Flow 1984-1985	Average 1926-1985
Aug '84	105,300	98,010	143,400	134,000
Sep '84	57,830	60,170	98,060	92,670
Oct '84	41,080	50,740	89,870	88,170
Nov '84	41,840	46,780	101,900	91,610
Dec '84	26,470	43,220	77,920	95,220
Jan '85	26,870	38,740	73,430	92,310
Feb '85	26,090	41,830	80,700	105,000
Mar '85	33,970	48,720	99,380	120,470
Apr '85	114,500	114,520	251,100	218,750
May '85	281,700	265,100	429,100	417,070
Jun '85	250,800	314,630	359,300	469,420
Jul '85	128,500	186,600	162,200	252,840
YEAR	94,580	109,050	163,860	181,410

SEASONAL RUNOFF FORECASTS AND VOLUMES

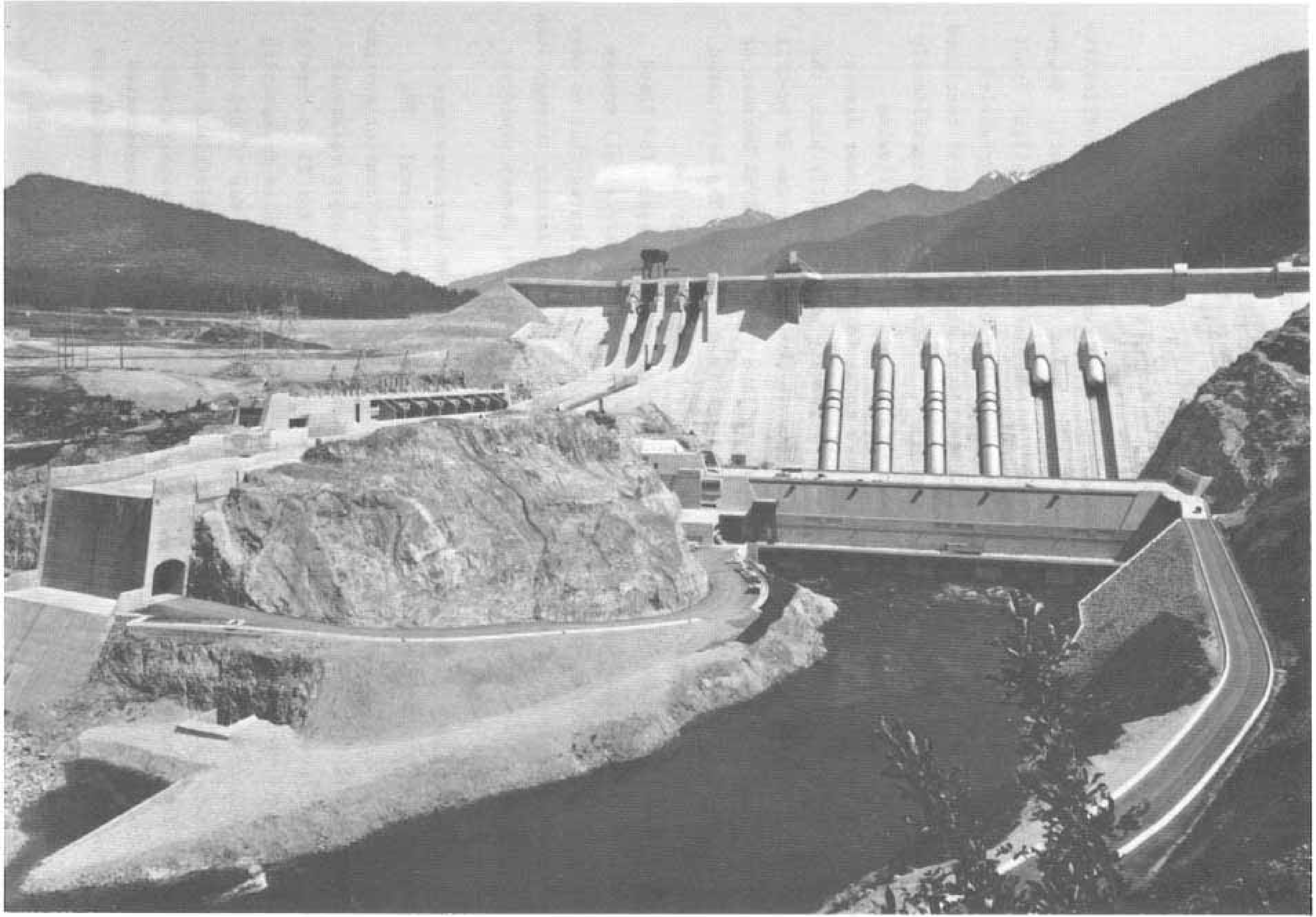
Observed 1985 April through August runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume In 1000 Acre-Feet	Percent of 1961-80 Average
Libby Reservoir Inflow	4,767	72
Duncan Reservoir Inflow	1,802	87
Mica Reservoir Inflow	9,923	85
Arrow Reservoir Inflow	20,661	88
Columbia River at Birchbank	34,866	84
Grand Coulee Reservoir Inflow	51,134	81
Snake River at Lower Granite Dam	19,958	85
Columbia River at The Dalles	78,411	82

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 1985 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 seasonal volume inflow forecasts for Mica, Arrow, Duncan, and Libby projects and for the 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 1985 forecast of January through July runoff for the Columbia River above The Dalles was 98.6 maf and the actual observed runoff was 87.7 maf, a 12 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



REVELSTOKE PROJECT. The project was dedicated on 29 August 1985 by British Columbia Premier W. R. Bennett.

V. RESERVOIR OPERATION

GENERAL

The operating year began with the coordinated reservoir system officially declared full on 1 August 1984 since it was at least 98 percent full. However the system was short on refill by about 1 million acre-feet. A slight draft of the reservoir system occurred in August because of several unscheduled thermal plant outages. A gradual draft for power and flood control continued throughout the autumn months. The system draft rate increased significantly in December as special power marketing arrangements were made allowing extensive drawdown of the reservoir system in anticipation of lower January rule curves. Water supply forecasts for 1 January were unusually high, the result of a very large accumulation of snow in November. The use of On-Call storage in Treaty reservoirs was considered late in December 1984 because of the abundant water supply forecast but no action was taken. The forecasted runoff picture began to change in January due to unseasonably low precipitation for several weeks. Rapid draft of reservoir space for flood control and power continued through January and into February at all treaty projects except Libby, where the water supply forecast indicated that no more draft was necessary. Tables 1 through 5 show the monthly January through June 1985 volume runoff forecasts and VECC computations for the Treaty projects.

Treaty project inflows began rising in April 1985 but increases were moderate until mid-May when temperatures rose to well above normal. The reservoir system was not regulated on a daily basis for flood control anytime during the 1985 runoff season because of considerably more empty reservoir space being available due to power operations than required for flood control use. Weekly flood control Columbia Basin Telecom (CBT) messages designating minimum flood control space requirements were issued between May 10 and June 6, and some small amounts of system flood control space was maintained until June. Above normal temperatures in late June did not trigger significant additional runoff and it became apparent in late June that the coordinated reservoir system would not fill during the summer of 1985. The coordinated reservoir system filled only to 92 percent of capacity by 31 July 1985. Proportional draft of the U.S. coordinated reservoir system to meet firm power requirements began in July 1985. This proportional draft continued through September 1985.

The release of 3.45 maf of U.S. power storage was deferred from the fall and winter of 1984-85 until the downstream juvenile fish migration period, 15 April to 15 June 1985. Grand Coulee and other reservoirs were drafted to meet these flow requirements, sometimes referred to as water budget flows, in 1985 for the second time.

All thermal plants except Hanford were shut down for annual maintenance during the spring 1985 refill period as usual. Hanford went out of service for maintenance and refueling on 11 September 1985. Boardman operated during July and August 1985 to reduce draft requirements of the hydrosystem.

MICA RESERVOIR

As shown in chart 6, the Treaty storage space at Mica reservoir was refilled on 2 August 1984. However, as some of the non-Treaty storage space that was declared available at Mica earlier in the year pursuant to the non-Treaty storage agreement between B.C. Hydro and BPA was not full, the actual reservoir level was only at elevation 2463.8 ft. approximately 11 ft below its normal maximum pool elevation 2475.0 ft. Due to insufficient load requirements in B.C. Hydro's system and to avoid spilling at Mica, the reservoir continued to fill during August, reaching elevation 2472.3 ft on 29 August. The project outflow was then adjusted to equal inflow, maintaining the reservoir level about elevation 2471.0 ft through September.

During the period from 27 September to 3 October 1984, the 34,300 sfd Special Mica Storage stored at Mica in lieu of Seven Mile project initial filling was released from the Mica reservoir. This release, made under the terms of long term non-Treaty storage contract DE-MS79-84BP90946, fulfilled BCH obligations and consequently BPA issued BCH a Release and Discharge of claims for Seven Mile reservoir initial filling.

During the period from October to December 1984, Treaty storage at Mica was operated per 1984-85 DOP but there were some departures from the DOP outflows for Mica due to transfers of non-Treaty storages in and out of the various non-Treaty storage accounts at Mica by both B.C. Hydro and BPA to meet their respective system load requirements. Consequently, Mica reservoir was drawn down to elevation 2450.4 ft on 31 December, slightly higher than its operating rule curve, after adjusting for the non-Treaty storages.

Treaty storage continued to be drafted from the reservoir between January and early April 1985. During the period from 4 to 21 February, Mica project had to spill storage at a rate up to 19,000 cfs, for a total of 248,300 sfd during this period in order to maintain sufficient level at the Revelstoke reservoir. By 12 April, Mica reservoir was drawn down to elevation 2385.9 ft, its lowest level for the current operating year.

Mica began filling when the project outflow was reduced to zero on 13 April 1985. Most of the storage prior to mid-May went to the non-Treaty storage accounts rather than the Treaty storage accounts because inflows into Mica reservoir were below the 10,000 cfs DOP target for the refill period. Inflows increased to above normal after mid-May 1985, peaking at 75,800 cfs on 25 May. Despite well-below average runoff in June and July, Mica continued to fill with outflows varying between zero and 30,000 cfs. Again, departure from the DOP release schedule was due to transfers of storages in and out of the various non-Treaty storage accounts at Mica.

The Treaty storage space at Mica was completely filled on 25 July 1985. The actual reservoir level was at elevation 2453.0 ft, approximately 22 feet below its normal maximum pool elevation 2475.0 ft. The reservoir reached its highest elevation of the year, 2453.9 ft, on 4 August 1985. During August and September, storages were released from the non-Treaty storage accounts by both B.C. Hydro and BPA, drafting the reservoir to elevation 2452.0 ft by 30 September 1985.

REVELSTOKE RESERVOIR

Revelstoke reservoir began initial filling in October 1983. By 13 August 1984, the reservoir was filled for the first time to elevation 1877.8 ft, slightly below its normal full pool elevation 1880.0 ft. Subsequent to BCH filling one half (1.150 maf) of the Inactive Storage space at Revelstoke, BCH received a Release and Discharge of Claims from BPA for the initial filling of Revelstoke reservoir.

The fourth generating unit at Revelstoke began commercial operation on 25 January 1985. During the 1984-85 operating year, the project was operated basically as a run-of-river plant. However, the reservoir did fluctuate to as low as elevation 1867.2 ft and as high as elevation 1879.6 ft as required to meet B.C. Hydro's system load and other requirements. During the period from 14 to 19 February 1985, the Revelstoke project was spilling at a rate as high as 33,500 cfs for a total of 112,910 sfd in order to meet Treaty storage release requirements at Arrow reservoir.

ARROW RESERVOIR

As shown in chart 7, Arrow reservoir was filled to elevation 1441.5 ft on 31 July 1984. After accounting for the 82,500 sfd of Treaty storage temporarily stored at Revelstoke reservoir, Treaty storage at Arrow was considered full. From August to September 1984, the Arrow project outflow was adjusted to discharge natural flows and to accommodate transfers of storages in and out of the various non-Treaty storage accounts at Mica, Revelstoke and Arrow reservoirs. During the period from October to December, operation of the Treaty storage at Arrow (including the Arrow Treaty storage at Revelstoke) followed the flood control rule curve. Project outflows during this period varied between 5,000 cfs and 62,000 cfs and the reservoir was drawn down to slightly below its flood control rule curve on 31 December after adjusting for the storage imbalance between Revelstoke and Arrow reservoirs. Arrow was drafted heavily during January and February 1985, with project releases up to 95,000 cfs. Treaty storage at Arrow was completely drafted by 20 March, however, because of the non-Treaty storage transferred earlier from Revelstoke to Arrow, the Arrow reservoir was able to maintain its level at elevation 1382.5 ft, approximately 5 ft above its normal minimum level of 1377.9 ft.

Arrow reservoir began filling in early April 1985. With project outflow reduced to as low as 5,000 cfs, the project was able to fill to elevation 1415.2 ft by 31 May, approximately 13 ft higher than its variable refill curve. Inflows into the reservoir peaked at 112,390 cfs on 24 May.

By early July 1985, after it was recognized that the runoff in the Columbia River Basin would not be sufficient to refill all projects, it became necessary for Arrow reservoir discharges to be increased to help fill other major reservoirs proportionally. As a result, Arrow only filled to elevation 1435 ft by late June 1985 and was maintained at that level until the project resumed filling on 20 July. By 31 August, Arrow reservoir was filled to approximately 1 ft below normal full pool and by 30 September 1985 the reservoir was at elevation 1444.9 ft, slightly above normal full pool.

DUNCAN RESERVOIR

As shown in chart 8, Duncan reservoir was filled to its normal full pool elevation 1892.0 ft on 29 July 1984. During the period from August until early November, the project discharged inflow. On 27 August runoff from heavy rain temporarily surcharged the reservoir to elevation 1892.8 ft.

Storage draft at Duncan began on 11 November 1984 when the project discharge was increased to 10,000 cfs to deliver Treaty storage to meet generation requirements in the U.S. system. The project maintained this rate of release until 28 December, except for a period between 19 and 23 November when the project outflow was reduced to 1,000 cfs. By 28 December, Duncan reservoir was drawn down to elevation 1849.5 ft, approximately 8 ft higher than its operating rule curve. Duncan reservoir continued to draft during January and February 1985, with discharges varying between 5,000 cfs and 7,000 cfs. The project reached elevation 1802.9 ft, its lowest level for the 1984-85 operating year, on 2 March 1985.

On 3 March 1985, Duncan project discharge was reduced to 100 cfs and the reservoir began to fill. Inflows into Duncan reservoir were below average during March and April but increased to above normal after mid-May and peaked at 18,200 cfs on 24 May. Beginning 25 May, Duncan project discharge was maintained at 1,000 cfs. By 31 May Duncan reservoir was filled to elevation 1845.7 ft, approximately 16 ft higher than its variable refill curve. Despite well below normal runoff in June 1985, the project continued to fill rapidly during the month.

By early July it was recognized that there would not be sufficient runoff to fill all projects. Therefore on 13 July 1985 with the Duncan reservoir at elevation near 1886 ft, the project discharge was increased to equal inflow to help fill other system reservoirs proportionally. As a result, Duncan reservoir reached its maximum elevation of the year, 1886.8 ft on 7 August 1985. On 10 August the project began drafting. By 31 August 1985, approximately 9 ft of storage had been drafted out of Duncan reservoir, lowering the reservoir to elevation 1878.6 ft. Duncan reservoir continued to draft during September and was at elevation 1872.6 ft on 30 September 1985.

LIBBY RESERVOIR

On 31 July 1984, Lake Koocanusa was at normal full pool elevation of 2459.0 ft as shown in chart 9. The lake remained near this level until 19 August when it began drafting to meet power commitments. The lake continued drafting throughout autumn with an average discharge of 13,000 cfs in October and November. By 30 November 1984 the lake elevation was 2422.4 ft, approximately 27 ft below the 1 December flood control requirement. The draft rate increased in December with the project discharge being maintained near 20,000 cfs until mid-month when it was increased to 24,000 cfs as unit 5 became available for commercial service on 11 December.

The lake elevation was 2391.9 ft on 31 December 1984, approximately 16 ft below the 1 January base energy content curve and 18 ft below the 1 January flood control rule curve. This draft below ECC occurred because BPA requested, and the Corps of Engineers approved this extra draft due to the unseasonably heavy autumn snowpack and an expected high runoff volume forecast which would result in significant lowering of rule curves. The project continued discharging at full powerhouse capacity until the end of January 1985 when the release was reduced because weather conditions had become dry in the Kootenai River Basin, resulting in a decreased volume forecast. The outflow was reduced to the preferred minimum of 4,000 cfs by mid-February and then to the absolute minimum of 3,000 cfs on 1 April because of concern about project refill. The lake reached its lowest level, 2341.8 ft on 1 April 1985.

The inflow to Lake Koocanusa began increasing in late April 1985 and the seasonal peak inflow of 56,100 cfs occurred on 25 May. By the end of June the inflow had receded to 15,000 cfs. The outflow was held at 3,000 cfs during most of the refill season but it became apparent by late June that there would not be sufficient runoff to completely refill the coordinated reservoir system, including Lake Koocanusa, because BPA had decided to market all its authorized energy, including an average of 1500 mw of surplus firm starting in July 1985. Consequently, Libby discharge was increased and the project passed inflow for the remainder of July. The lake reached its highest elevation of 2449.9 ft, 9 ft below full pool, on 28 July 1985. By reducing the project discharge from 4,000 cfs to 3,000 cfs on 1 April, the lake filled 4.5 ft higher by mid-July 1985 than it otherwise would have. The project continued to pass inflow through the end of August and then in September the discharge was increased in accordance with proportional draft requirements. The lake was at elevation 2444.3 on 30 September 1985.

KOOTENAY LAKE

As shown in chart 10, Kootenay Lake was gradually drawn down during July and August after filling to its peak in June 1984. By 31 August 1984, Kootenay Lake was drafted to elevation 1743.3 ft. Between 1 September and 25 October 1984, Kootenay Lake outflow was reduced as required to prevent spill at the Brilliant project. During this period inflows into Kootenay Lake were sufficient to fill the lake to elevation 1745.1 ft by 20 October, slightly below the International Joint Commission (IJC) rule curve elevation 1745.3 ft. During November and December, Kootenay Lake maintained its level near elevation 1745.0 ft, discharging between 16,000 cfs and 35,000 cfs.

Following the IJC rule curve, Kootenay Lake was drafted during the period January through March 1985. Discharge was reduced to as low as 10,000 cfs during March due to below average inflows into Kootenay Lake. By 1 April 1985, Kootenay Lake was drawn down to elevation 1738.9 ft, its lowest level for the current operating year.

Kootenay Lake began to fill in early April and by 19 April 1985 it was at elevation 1740.3 ft. The lake was drafted slighly because of low inflows before it resumed filling to a peak elevation of 1747.5 ft on 30 June 1985. With outflows as high as 52,000 cfs, Kootenay Lake was drawn down below elevation 1743.32 ft, its IJC rule curve for summer operation, on 9 July. Kootenay Lake then discharged inflows, maintaining its level slightly below the IJC rule curve during July and August.

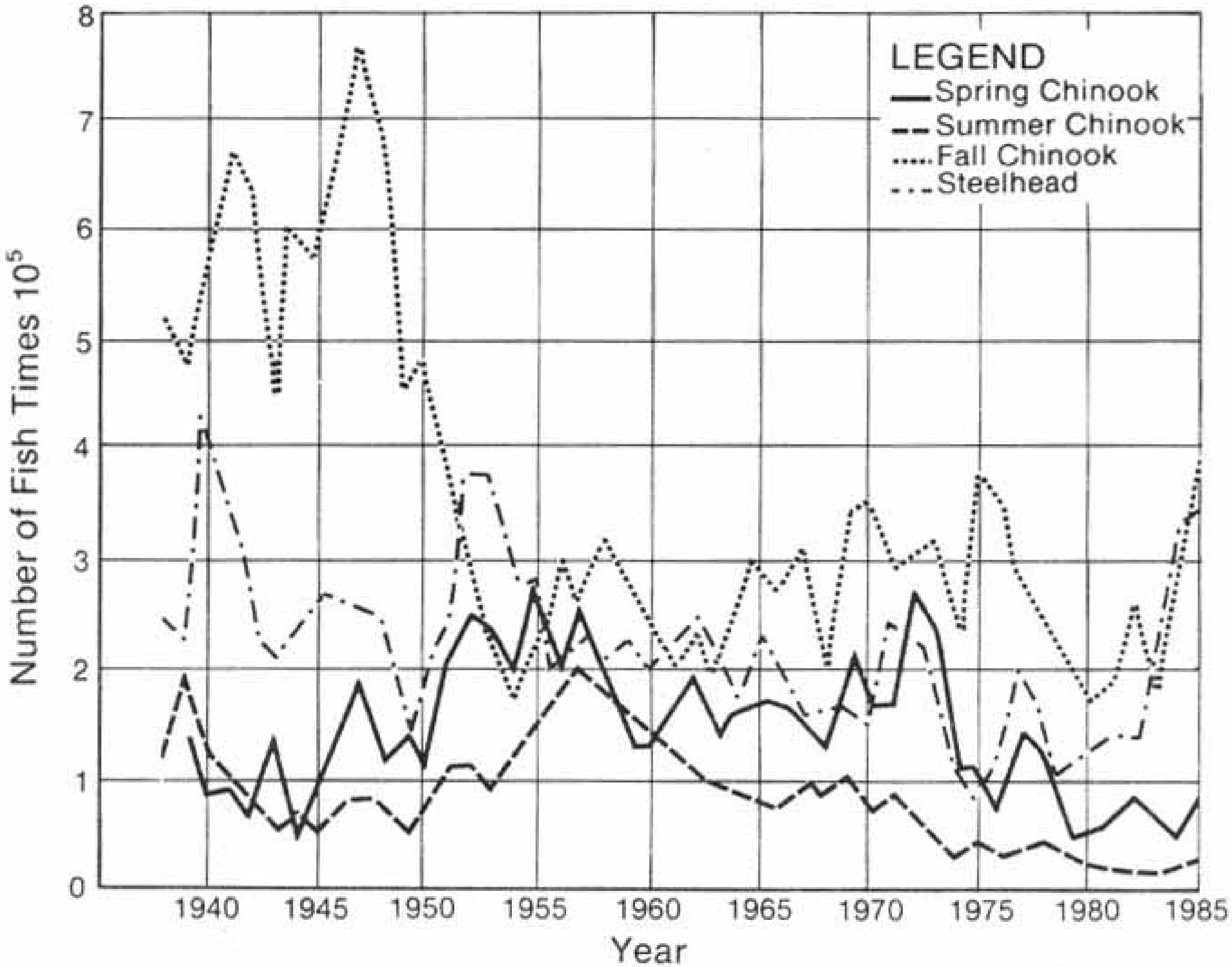
Beginning 1 September 1985, Kootenay Lake outflow was reduced to prevent spill at the Brilliant project and begin filling the lake towards elevation 1745.32 ft, the IJC rule curve for winter operation. On 30 September 1985 the lake was at elevation 1744.4 ft.

HISTORICAL OPERATIONS SUMMARY

The following listing summarizes the January through July forecasted and actual runoff in the Columbia Basin above The Dalles each year since 1967, the first year a treaty reservoir (Duncan) was put into operation. The 20-year (1961-80) average runoff is 106.9 million acre-feet (maf). The annual refill status of the Columbia reservoir system is also summarized in the listing.

Year	Jan-Jul Runoff above The Dalles				Reservoir System Refill Status
	Forecasted		Actual		
	1 Jan (maf)	1 Apr (maf)	(maf)	(%)	
1967	108.3	118.0	112.3	105	All available space filled including initial filling of Duncan which was started in May and completed in July.
1968	92.2	100.3	95.9	90	All major reservoirs filled including initial portion of Arrow.
1969	111.8	120.1	108.2	101	All major reservoirs filled including Arrow for first time and Grand Coulee after unusual deep draft for third powerhouse construction.
1970	82.5	94.3	95.7	90	Reservoir system refilled. The NW-SW d-c intertie began full commercial operation on 21 May.

Year	Jan-Jul Runoff above The Dalles				Reservoir System Refill Status
	Forecasted		Actual		
	1 Jan (maf)	1 Apr (maf)	(maf)	(%)	
1971	110.9	134.0	137.5	129	All available space filled.
1972	110.1	146.1	151.7	142	All available space filled including initial filling of Libby and Dworshak up to spillway crests.
1973	93.1	83.0	71.2	67	Initial filling started at Mica but system lacked 10 maf refilling including Libby, Hungry Horse, Grand Coulee, Arrow, Duncan and Mica.
1974	123.0	146.0	156.3	146	All reservoirs refilled except non-treaty space in Mica.
1975	96.1	116.7	112.4	105	All major reservoirs refilled except Libby and non-treaty space in Mica.
1976	113.0	124.0	122.8	115	All major reservoirs refilled including all Mica non-treaty space for the first time.
1977	75.7	58.1	53.8	50	Major reservoir system failed to refill by 12 maf.
1978	120.0	101.0	105.6	99	All major reservoirs refilled.
1979	88.0	87.3	83.1	78	System failed to refill by 5 maf including space at Libby, Mica, Arrow, and Grand Coulee.
1980	88.9	89.7	95.8	90	All major reservoirs refilled plus non-treaty space at Arrow.
1981	106.0	81.9	103.4	97	All major reservoirs refilled plus non-treaty space at Arrow.
1982	110.0	130.0	129.9	122	All major reservoirs refilled.
1983	110.0	121.0	118.7	111	All major reservoirs refilled plus non-treaty space in Arrow and Mica.
1984	113.0	102.0	119.1	111	All reservoirs filled, including Revelstoke for first time, except for about 1 maf, mostly non-treaty space in Mica.
1985	131.0	98.6	87.7	82	System failed to refill on 31 July by almost 5 maf including space in Mica, Arrow, Duncan, Libby, and Grand Coulee.



COLUMBIA RIVER FISH COUNTS. Ever since the Army Corps of Engineers' Bonneville Dam became operational in 1938, the states of Washington and Oregon through their departments of fisheries, have been jointly making estimates of the total numbers of adult fish entering the mouth of the Columbia River destined for spawning areas above Bonneville. These data are based on actual counts at Bonneville Dam fish ladders and estimates of commericial and sport catches in the river below Bonneville. The 1985 data are preliminary and subject to revision.

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. "Columbia River Treaty Hydroelectric Operating Plan - Assured Operating Plan for Operating Year 1984-85," dated September 1979.
2. "Detailed Operating Plan for Columbia River Treaty Storage - 1 August 1984 through 31 July 1985," dated September 1984.
3. "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 1984-85 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 1984-85 Assured Operating Plan prepared in 1979, was used as the basis for the preparation of the 1984-85 Detailed Operating Plan.

POWER

The Canadian Entitlement to downstream power benefits from Duncan, Arrow and Mica for the 1984-85 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 468 average megawatts at rates up to 1,172 megawatts from 1 August 1984 through 31 March 1985, and 444 average megawatts at rates up to 1,134 megawatts from 1 April 1985 through 31 July 1985. All CSPE power was used to meet Pacific Northwest loads during the period of this report.

The coordinated reservoir system was more than 98 percent full on 1 August 1984 and after being drawn down during the 1984-85 operating year, recovered to only 92 percent full on 31 July 1985. The following table shows the status of the energy stored in the coordinated system in billions of kilowatt-hours at the end of each month compared to rule curves during the 1984-85 operating year:

Month	Rule Curves	Actual	Difference
Aug '84	46.4	45.1	-1.3
Sep '84	43.8	43.2	-0.6
Oct '84	40.8	40.0	-0.8
Nov '84	36.6	37.0	0.4
Dec '84	33.0	30.8	-2.2
Jan '85	16.0 1/	21.4	5.4
Feb '85	12.8 1/	13.7	0.9
Mar '85	9.7 1/	9.6	-0.1
Apr '85	13.3 1/	13.6	0.3
May '85	23.7 1/	28.3	4.6
Jun '85	39.5 1/	40.0	0.5
Jul '85	46.3	42.8	-3.5

1/ NOTE: Rule curves were lowered due to volume runoff forecasts shown in table 1.

On 14 September 1984 BPA implemented a new Pacific Southwest Intertie Access Policy designed to enhance BPA's power marketing program. The new policy assures BPA full access to its portion of the intertie and established a more equitable allocation of intertie access when demand by Pacific Northwest utilities exceeds available line capacity. BPA's policy limits the Canadian utilities access to the intertie to the capacity remaining after Pacific Northwest utilities have declared their surplus available for sale. Notwithstanding the new policy, B.C. Hydro experienced record sales to the United States during the 1984-85 operating year. BCH sold a total of 37.88-billion kwh of electricity during the 12 months ended 31 March 1985, including record exports of 6.378-billion kwh of surplus electricity. The following table shows BPA nonfirm and surplus firm sales in megawatt-hours to northwest and southwest utilities during the 1984-85 operating year.

	To Northwest Utilities		To Southwest Utilities	
Period	Nonfirm	Surplus Firm	Nonfirm	Surplus Firm
Aug '84	1,375	278,400	0	777,966
Sep '84	0	36,240	0	956,449
Oct '84	0	7,450	0	1,092,979
Nov '84	11,475	7,200	0	1,319,961
Dec '84	31,511	0	0	1,178,285
Jan '85	1,488,360	15,000	886,033	532,836
Feb '85	202,299	16,000	1,829,613	337,615
Mar '85	727,585	14,540	81,846	166,723
Apr '85	608,899	10,800	1,584,745	72,000
May '85	197,061	11,160	2,765,545	74,400
Jun '85	133,377	10,800	1,468,244	374,277
Jul '85	0	2,780	0	1,112,280
TOTAL	3,401,942	410,370	8,616,026	7,995,771

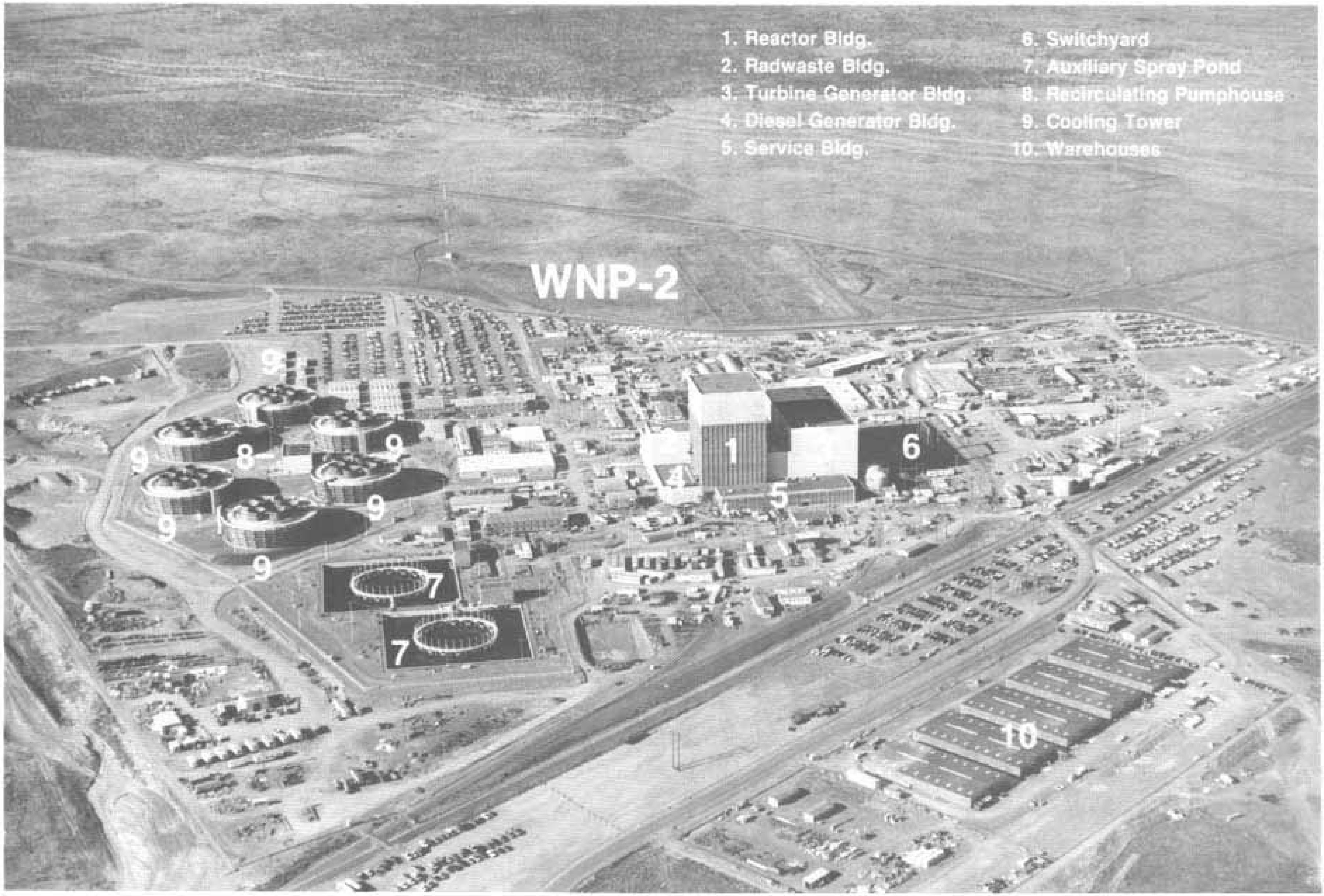
FLOOD CONTROL

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made periodically as usual before and during the 1985 spring runoff season in accord with the Treaty Flood Control Operating Plan. The results of these computations started out on 1 January 1985 at 480,000 cfs then decreased to 400,000 cfs on 1 February, 365,000 cfs on 1 March, 350,000 cfs on 1 April and 320,000 cfs on 1 May. Data for the 1 May ICF computation are given in table 6.

Because it was anticipated in December that a high runoff forecast would make a large amount of reservoir storage available beginning in January, special arrangements were made in December for U.S. reservoirs to immediately increase outflows to serve additional power markets. This large early drawdown and the subsequent below normal precipitation and seasonal runoff resulted in much more flood control space being available than normally would have been required under the circumstances.

For the above reasons it was not necessary to operate the Columbia reservoir system on a daily basis for flood control anytime during the 1985 runoff season. Instead, minimum flood control space requirements were established on a weekly basis between 10 May and 6 June 1985. In most cases, much more space was actually available than these weekly minimum requirements, consequently flood control operations had a minimum effect on spring refill conditions. Streamflow forecasts indicated that even with high temperatures, the normal reservoir refill operation would keep river levels below flood stage.

Flood control during the spring 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 during 1 July 1984 through 31 July 1985 are shown with a summary hydrograph on chart 13 for comparison with historical flows. As shown on chart 14 the unregulated peak at The Dalles would have been 550,000 cfs on 27 May 1985 and it was controlled to a maximum observed mean daily flow at The Dalles of 279,000 cfs on 6 May. The observed peak stage at Vancouver, Washington was 9.5 ft, whereas floodstage is 16.0 ft. The peak inflow of the Snake River at Lower Granite was 124,400 cfs on 8 June 1985. Chart 14 also shows the effect of Mica, Arrow, Duncan and Libby regulations on the flow at The Dalles during the April through July 1985 freshet period. Chart 15 documents the relative filling of Arrow and Grand Coulee during the principal filling period, and compares the regulation of the two reservoirs to guidelines in the Treaty Flood Control Operating Plan.



WPPSS NUCLEAR PLANT NO. 2. WNP-2 is a boiling water nuclear reactor owned and operated by the Washington Public Power Supply System on the Hanford Reservation near Richland, Washington. The plant, which began commercial operation in December 1984, generates 1100 mw when at full power.

Table 1

Unregulated Runoff Volume Forecasts
Millions of Acre-Feet
1985

Forecast Date - 1st of	DUNCAN Most Probable 1 April-31 August	ARROW Most Probable 1 January-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 January-31 July
January	2.4	24.7	12.1	7.0	131.0
February	1.9	21.5	10.8	6.3	109.0
March	1.9	21.8	10.8	5.9	105.0
April	1.8	20.6	10.6	5.6	98.6
May	2.0	21.6	10.7	5.5	98.6
June	2.0	21.9	10.9	5.4	100.0
Actual	1.8	20.7	9.9	4.8	87.7

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 1985

	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]		4834.9	4486.3	4577.1	4421.5	4472.2	4632.5
2 95% FORECAST ERROR, KSFD		718.3	537.9	498.3	485.6	457.9	448.9
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD [2]		4116.6	3948.4	4078.8	3935.9	4014.3	4183.6
4 OBSERVED FEB 1 - DATE INFLOW, KSFD				136.1	204.4	423.9	1458.1
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD [3]		4116.6	3948.4	3942.7	3731.5	3590.4	2725.5
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]		4116.6					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		2180.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]		1592.6					
MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		2430.7					
JAN 31 ECC, FT [7]		2430.7					
BASE ECC, FT	2435.7						
LOWER LIMIT, FT	2411.4						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.8	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		4026.0	3865.5				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1760.0	1760.0				
MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]		1263.2	1423.7				
MIN. FEB 28 RESERVOIR ELEVATION, FT [6]		2423.4	2427.0				
FEB 28 ECC, FT [7]		2422.2	2422.2				
BASE ECC, FT	2422.2						
LOWER LIMIT, FT	2401.9						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		95.4	95.6	97.7			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		3927.2	3774.7	3852.0			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1295.0	1295.0	1295.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		897.0	1049.5	972.2			
MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		2415.2	2418.7	2416.9			
MAR 31 ECC, FT [7]		2413.9	2413.9	2413.9			
BASE ECC, FT	2413.9						
LOWER LIMIT, FT	2393.7						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		91.0	91.0	93.0	95.2		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		3746.1	3593.0	3666.7	3552.4		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		920.0	920.0	920.0	920.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		703.1	856.2	782.5	896.8		
MIN. APR 30 RESERVOIR ELEVATION, FT [6]		2410.7	2414.3	2412.6	2415.2		
APR 30 ECC, FT [7]		2407.1	2407.1	2407.1	2407.1		
BASE ECC, FT	2401.7						
LOWER LIMIT, FT	2393.7						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		74.1	73.7	75.3	77.1	81.0	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		3050.4	2910.0	2968.9	2877.0	2908.2	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		610.0	610.0	610.0	610.0	610.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		1088.8	1229.2	1170.3	1262.2	1231.0	
MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		2419.5	2422.7	2421.4	2423.4	2422.7	
MAY 31 ECC, FT [7]		2416.1	2416.1	2416.1	2416.1	2416.1	
BASE ECC, FT	2416.1						
LOWER LIMIT, FT	2393.7						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		36.9	36.5	37.3	38.2	40.1	49.0
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		1519.0	1441.2	1470.6	1425.4	1439.8	1349.1
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]		2320.2	2398.0	2368.6	2413.8	2399.4	2490.1
MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		2446.0	2447.5	2446.9	2447.9	2447.6	2449.4
JUN 30 ECC, FT [7]		2445.9	2445.9	2445.9	2445.9	2445.9	2445.9
BASE ECC, FT	2445.9						
LOWER LIMIT, FT	2393.7						
JUL 31 ECC, FT	2469.8	2469.8	2469.8	2469.8	2469.8	2469.8	2469.8

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (3529.2 KSFD) PLUS PRECEDING LINE LESS LINE PRECEDING THAT (USABLE STORAGE)
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 1985

		INITIAL	JAN 1 TOTAL	FEB 1 LOCAL	MAR 1 LOCAL	APR 1 LOCAL	MAY 1 LOCAL	JUN 1 TOTAL
1	PROBABLE FEB 1 - JUL 31 INFLOW, KSFD [1]		10660.7	4928.3	5176.4	4738.0	5121.4	9891.5
2	95% FORECAST ERROR, KSFD		1546.3	948.7	802.3	633.6	555.5	856.3
3	95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD [2]		9114.4	3979.6	4374.1	4104.4	4565.9	9035.2
4	OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	276.0	342.5	860.3	3884.2
5	RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD [3]		9114.4	3979.6	4098.1	3761.9	3705.6	5151.0
	ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
	ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]		9114.4					
	MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		1454.0					
	MICA REFILL REQUIREMENTS, KSFD [8]		1936.6					
	MIN. JAN 31 RESERVOIR CONTENTS, KSFD [5]		2144.2					
	MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		1377.9					
	JAN 31 ECC, FT [7]		1384.5					
	BASE ECC, FT	1419.7						
	LOWER LIMIT, FT	1384.5						
	ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.5	97.2				
	ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		8886.5	3868.2				
	MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1314.0	1314.0				
	MICA REFILL REQUIREMENTS, KSFD [8]		2321.7	1760.0				
	MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]		1671.2	734.6				
	MIN. FEB 28 RESERVOIR ELEVATION, FT [6]		1377.9	1377.9				
	FEB 28 ECC, FT [7]		1380.1	1380.1				
	BASE ECC, FT	1402.9						
	LOWER LIMIT, FT	1380.1						
	ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		94.7	93.8	96.5			
	ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		8631.3	3732.9	3954.7			
	MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1159.0	1159.0	1159.0			
	MICA REFILL REQUIREMENTS, KSFD [8]		2688.3	1295.0	1295.0			
	MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		1204.4	289.3	511.1			
	MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		1377.9	1377.9	1377.9			
	MAR 31 ECC, FT [7]		1378.5	1378.5	1378.5			
	BASE ECC, FT	1411.4						
	LOWER LIMIT, FT	1378.5						
	ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		89.0	86.1	88.6	91.8		
	ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		8111.8	3426.4	3630.9	3453.4		
	MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		1009.0	1009.0	1009.0	1009.0		
	MICA REFILL REQUIREMENTS, KSFD [8]		2980.2	920.0	920.0	920.0		
	MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		543.1	242.2	37.7	215.2		
	MIN. APR 30 RESERVOIR ELEVATION, FT [6]		1377.9	1383.7	1378.9	1383.1		
	APR 30 ECC, FT [7]		1377.9	1383.7	1378.9	1383.1		
	BASE ECC, FT	1413.1						
	LOWER LIMIT, FT	1377.9						
	ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		68.7	62.2	64.0	66.3	72.3	
	ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		6261.6	2475.3	2622.8	2494.1	2679.1	
	MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		854.0	854.0	854.0	854.0	854.0	
	MICA REFILL REQUIREMENTS, KSFD [8]		2592.3	610.0	610.0	610.0	610.0	
	MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		764.3	1348.3	1200.8	1329.5	1144.5	
	MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		1395.0	1406.4	1403.6	1406.1	1402.6	
	MAY 31 ECC, FT [7]		1395.0	1406.4	1403.6	1406.1	1402.6	
	BASE ECC, FT	1426.0						
	LOWER LIMIT, FT	1377.9						
	ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		31.9	26.8	27.6	28.6	31.2	46.4
	ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		2907.5	1066.5	1131.1	1075.9	1156.1	2390.1
	MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		434.0	434.0	434.0	434.0	434.0	434.0
	MICA REFILL REQUIREMENTS, KSFD [8]		1211.8	310.0	310.0	310.0	310.0	1211.8
	MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]		2317.9	2637.1	2572.5	2627.7	2547.5	2835.3
	MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		1423.8	1429.1	1428.0	1428.9	1427.6	1432.3
	JUN 30 ECC, FT [7]		1423.8	1429.1	1428.0	1428.9	1427.6	1432.3
	BASE ECC, FT	1443.6						
	LOWER LIMIT, FT	1377.9						
	JUL 31 ECC, FT	1444.0	1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - 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 FEBRUARY 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

95 Percent Confidence Variable Energy Content Curve Duncan 1985

	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]		917.7	821.3	811.9	760.8	835.1	861.5
2 95% FORECAST ERROR, KSFD		154.7	118.6	113.5	105.6	95.4	94.0
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD [2]		763.0	702.7	698.4	655.2	739.7	767.5
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	12.1	27.3	80.5	309.8
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD [3]		763.0	702.7	686.3	627.9	659.2	457.7
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]		763.0					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		18.1					
MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]		-39.0					
MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		1794.2					
JAN 31 ECC, FT [7]		1797.6					
BASE ECC, FT	1833.9						
LOWER LIMIT, FT	1797.6						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.8	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		747.2	687.9				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		15.3	15.3				
MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]		-25.1	33.2				
MIN. FEB 28 RESERVOIR ELEVATION, FT [6]		1794.2	1801.7				
FEB 28 ECC, FT [7]		1799.0	1801.7				
BASE ECC, FT	1835.2						
LOWER LIMIT, FT	1799.0						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		95.4	95.5	97.5			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		727.9	671.1	669.1			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		12.2	12.2	12.2			
MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		-9.9	46.9	48.9			
MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		1794.2	1804.3	1804.7			
MAR 31 ECC, FT [7]		1794.6	1804.3	1804.7			
BASE ECC, FT	1837.2						
LOWER LIMIT, FT	1794.6						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		90.3	90.1	92.0	94.3		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		689.0	633.1	631.4	592.1		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		9.2	9.2	9.2	9.2		
MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		26.0	81.9	83.6	122.9		
MIN. APR 30 RESERVOIR ELEVATION, FT [6]		1800.2	1810.6	1810.9	1817.4		
APR 30 ECC, FT [7]		1800.2	1810.6	1810.9	1817.4		
BASE ECC, FT	1834.2						
LOWER LIMIT, FT	1794.2						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		70.5	69.7	71.2	73.0	77.4	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		537.9	489.8	488.6	458.4	510.2	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		6.1	6.1	6.1	6.1	6.1	
MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		174.0	222.1	223.3	253.5	201.7	
MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		1825.2	1832.2	1832.3	1836.6	1829.3	
MAY 31 ECC, FT [7]		1825.2	1832.2	1832.3	1836.6	1829.3	
BASE ECC, FT	1848.6						
LOWER LIMIT, FT	1794.2						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		33.3	32.4	33.1	33.9	36.0	46.5
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		254.1	227.7	227.2	212.9	237.3	212.8
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		3.1	3.1	3.1	3.1	3.1	3.1
MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]		461.5	481.2	481.7	496.0	471.6	496.1
MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		454.8	1865.9	1865.9	1867.6	1864.7	1867.6
JUN 30 ECC, FT [7]		1862.6	1865.9	1865.9	1867.6	1864.7	1867.6
BASE ECC, FT	1872.0						
LOWER LIMIT, FT	1794.2						
JUL 31 ECC, FT	1892.0	1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (705.8 KSFD) PLUS PRECEDING LINE LESS LINE PRECEDING THAT
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 5

95 Percent Confidence Forecast and Variable Energy Content Curve Libby 1985

		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................		3538.7	3171.8	3008.7	2792.3	2769.6	2726.9
2	95% FORECAST ERROR, KSFD		877.2	598.8	546.6	495.1	414.7	348.4
3	OBSERVED JAN 1 - DATE INFLOW, KSFD		0.0	83.8	154.6	236.2	447.4	1314.2
4	95% CONF. DATE - JUL 31 INFLOW, KSFD [1].............		2661.5	2489.2	2307.5	2060.0	1907.5	1064.3
	ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		96.9					
	ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [2]		2580.1					
	FEB MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0					
	MIN. FEB 1 - JUL 31 OUTFLOW, KSFD [4].................		543.0					
	MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]		473.4					
	MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		2337.4					
	JAN 31 ECC, FT [7]		2337.4					
	BASE ECC, FT	2407.7						
	LOWER LIMIT, FT	2330.4						
	ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		94.2	97.1				
	ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		2506.3	2418.0				
	MAR MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0				
	MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		459.0	459.0				
	MIN. FEB 1 RESERVOIR CONTENT, KSFD [5]		463.2	551.5				
	MIN. FEB 1 RESERVOIR ELEVATION, FT [6]		2336.5	2344.3				
	FEB 28 ECC, FT [7]		2336.5	2344.3				
	BASE ECC, FT	2406.3						
	LOWER LIMIT, FT	2307.6						
	ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		90.7	93.7	96.4			
	ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		2416.4	2331.4	2224.9			
	APR MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0	3000.0			
	MIN. APR 1 - JUL 31 OUTFLOW, KSFD		366.0	366.0	366.0			
	MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		460.1	545.1	651.6			
	MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		2336.3	2343.8	2353.0			
	MAR 31 ECC, FT [7]		2336.3	2343.8	2353.0			
	BASE ECC, FT	2405.1						
	LOWER LIMIT, FT	2289.3						
	ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		81.7	84.3	86.8	90.0		
	ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		2174.7	2098.2	2002.2	1954.0		
	MAY MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0	3000.0	3000.0		
	MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		276.0	276.0	276.0	276.0		
	MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		611.8	688.3	784.3	932.5		
	MIN. APR 30 RESERVOIR ELEVATION, FT [6]		2349.7	2356.0	2363.6	2374.5		
	APR 30 ECC, FT [7]		2349.7	2356.0	2363.6	2374.5		
	BASE ECC, FT	2403.7						
	LOWER LIMIT, FT	2287.0						
	ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		52.8	54.4	56.0	58.1	64.6	0.0
	ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		1403.9	1354.6	1292.7	1196.8	1231.5	0.0
	JUN MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0	3000.0	3000.0	3000.0	0.0
	MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		183.0	183.0	183.0	183.0	183.0	0.0
	MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		1289.6	1338.9	1400.8	1496.7	1462.0	0.0
	MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		2398.3	2401.3	2405.0	2410.7	2408.7	0.0
	MAY 31 ECC, FT [7]		2398.3	2401.3	2405.0	2410.7	2408.7	0.0
	BASE ECC, FT	2427.6						
	LOWER LIMIT, FT	2287.0						
	ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		19.0	19.6	20.2	20.9	23.2	36.0
	ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		504.9	487.1	465.0	430.5	442.9	382.8
	JUN MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0	3000.0	3000.0	3000.0	3000.0
	MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		93.0	93.0	93.0	93.0	93.0	93.0
	MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]		2098.6	2116.4	2138.5	2173.0	2160.6	2220.7
	MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		2440.3	2441.1	2442.2	2443.8	2443.2	2446.1
	JUN 30 ECC, FT [7]		2440.3	2441.1	2442.2	2443.8	2443.2	2446.1
	BASE ECC, FT	2452.6						
	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 [8]		118.0	111.0	111.0	98.6	97.7	95.1

1 LINE 1 - LINE 2 LINE 3.
2 PRECEDING LINE TIMES LINE 4.
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 ELEVATION FROM 5, STORAGE CONTENT TABLE, DATED JUNE 1980.
7 ELEVATION FROM 6, BUT LIMITED BASE ECC, AND 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 1985

1 May Forecast of May-August Unregulated Runoff Volume, MAF		76.8
Less Estimated Depletions, MAF		1.5
Less Upstream Storage Corrections, MAF		
MICA	6.2	
ARROW	5.0	
LIBBY	3.7	
DUNCAN	1.2	
HUNGRY HORSE	1.4	
FLATHEAD LAKE	.5	
NOXON	.0	
PEND OREILLE LAKE	.5	
GRAND COULEE	4.2	
BROWNLEE	.4	
DWORSHAK	1.2	
JOHN DAY	.2	
TOTAL	24.5	24.5
Forecast of Adjusted Residual Runoff Volume, MAF		50.8
Computed Initial Controlled flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		320.0

Chart 1
Seasonal Precipitation
Columbia River Basin
October 1984 - March 1985
Percent of 1961-1980 Average

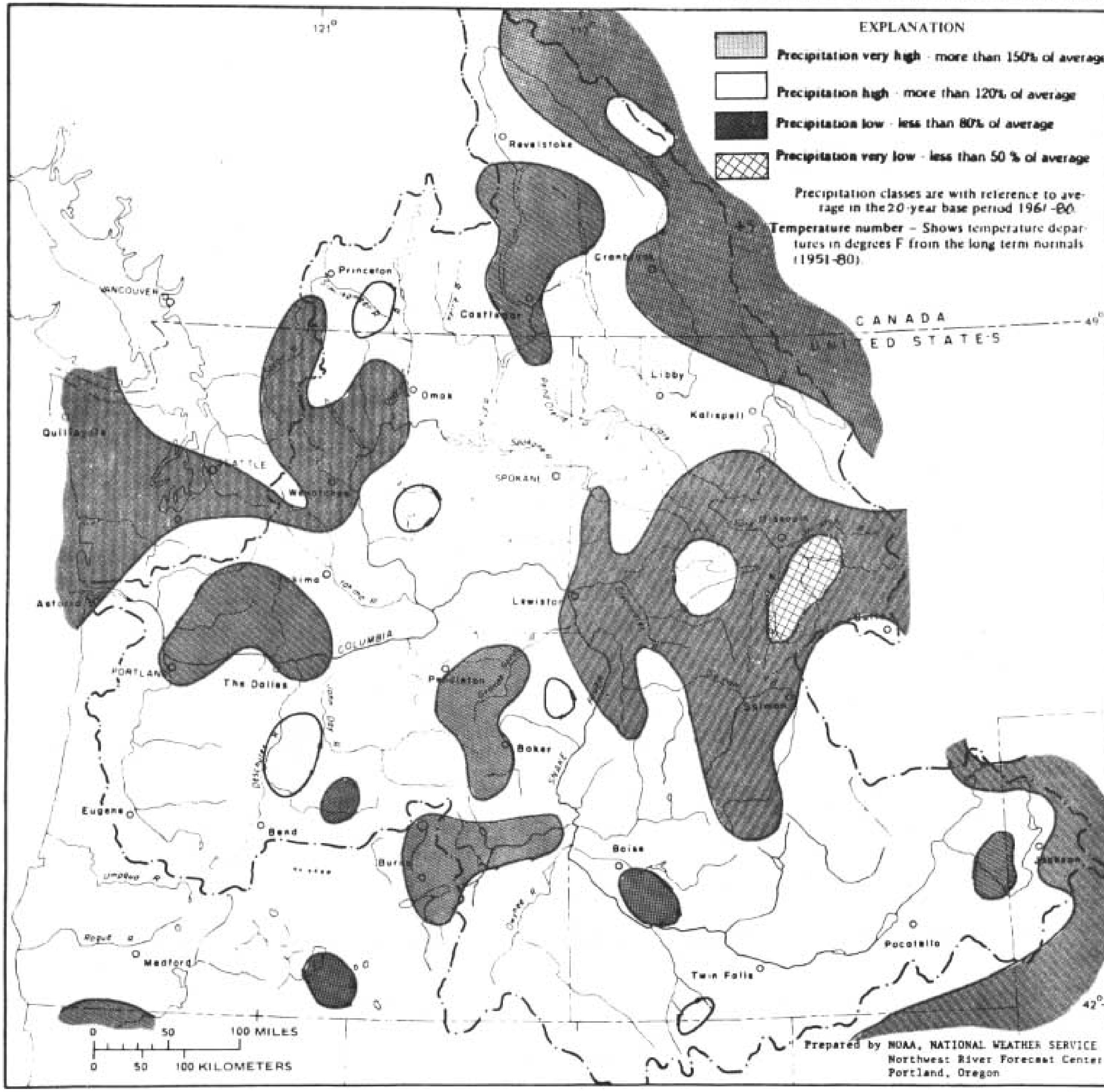


Chart 2
Columbia Basin Snowpack

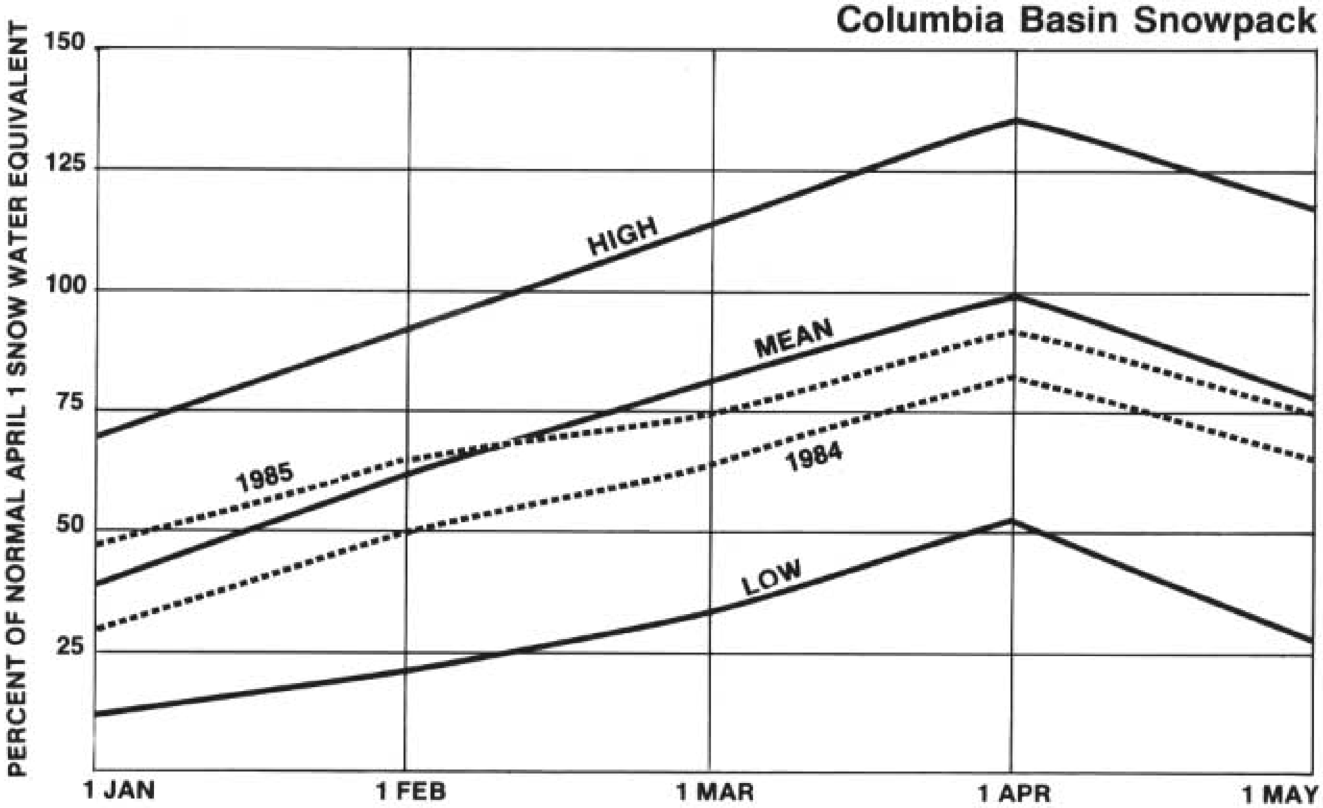


Chart 3
Winter Season
Temperature and Precipitation Indexes 1984-1985
Columbia River Basin above The Dalles

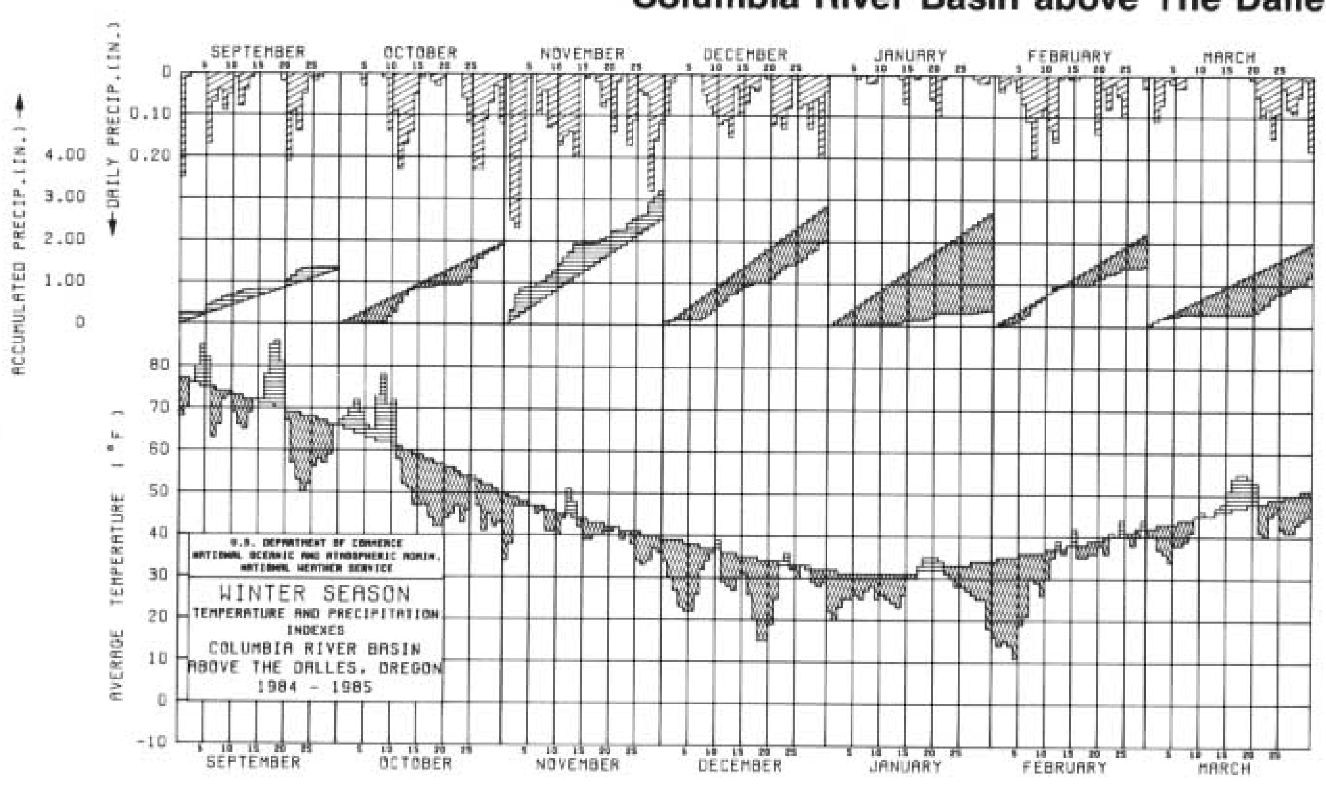


Chart 4
Snowmelt Season
Temperature and Precipitation Indexes 1984-1985
Columbia River Basin above The Dalles

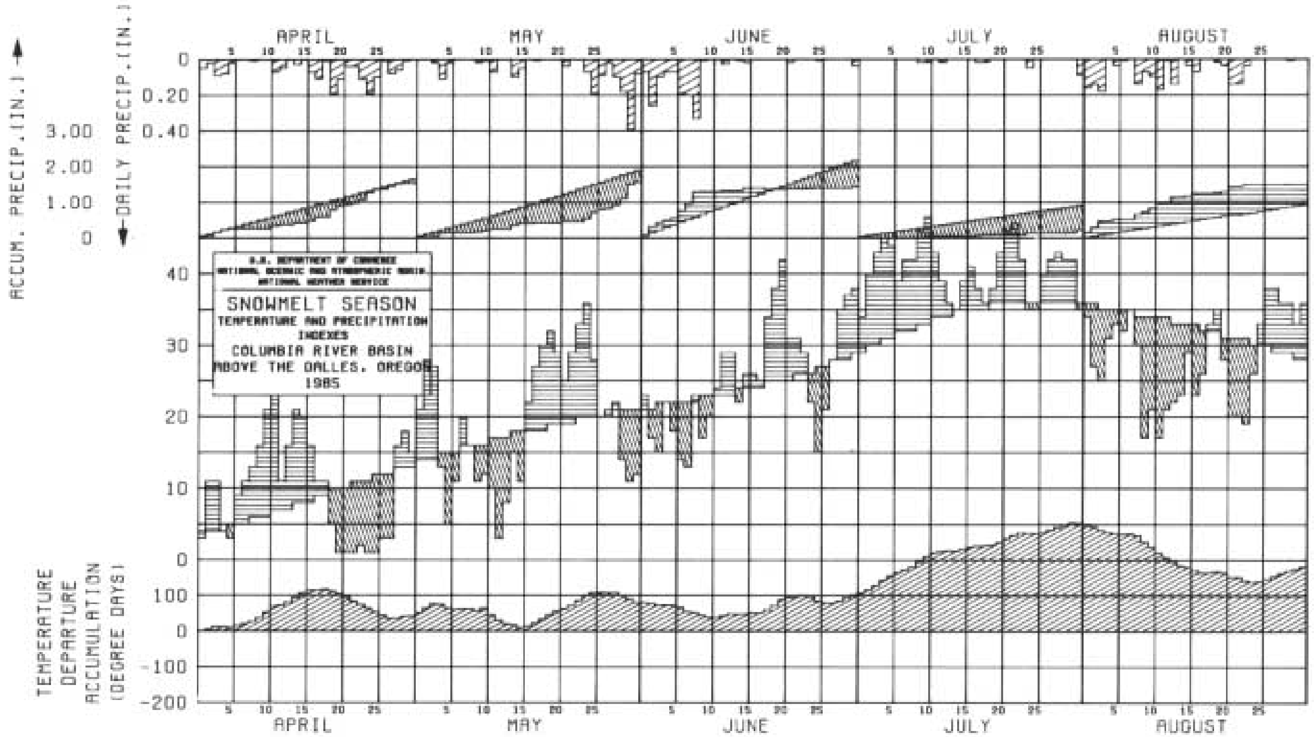


Chart 5
Snowmelt Season
Temperature and Precipitation Indexes 1984-1985
Columbia River Basin in Canada

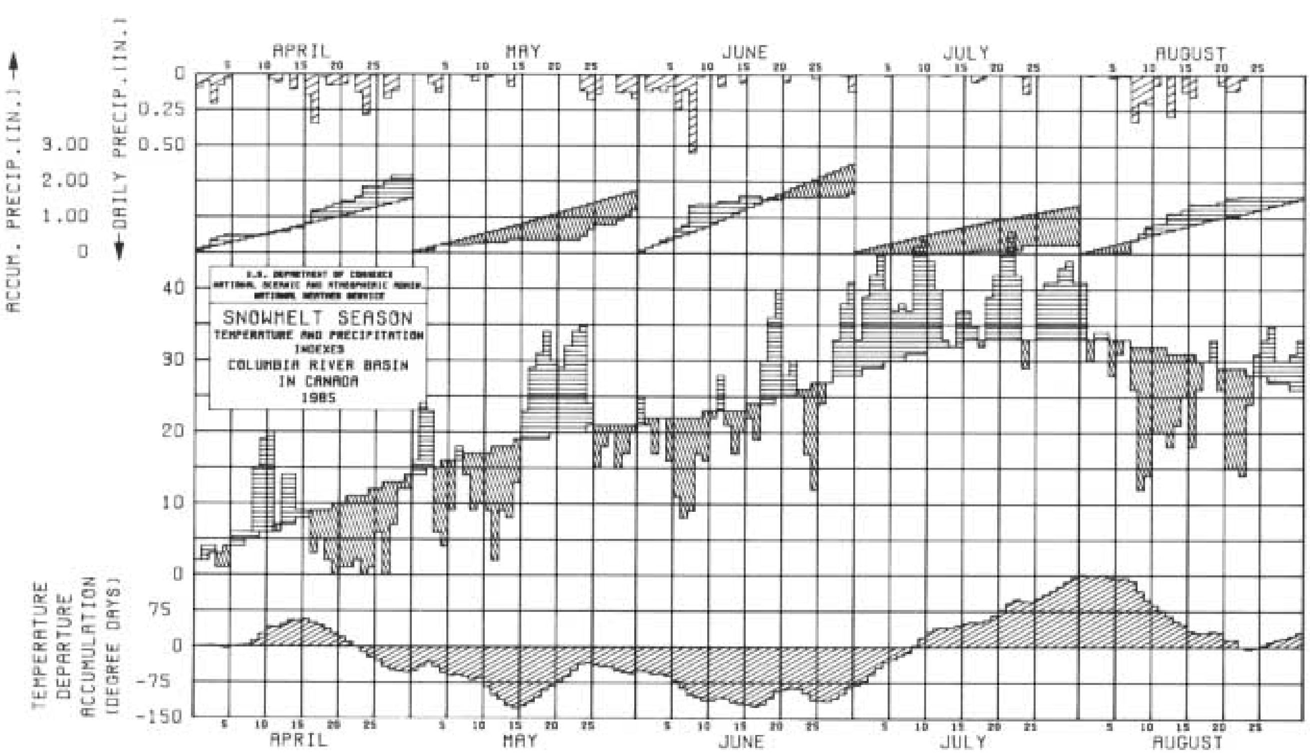


Chart 6

Regulation of Mica
1 July 1984 — 31 July 1985

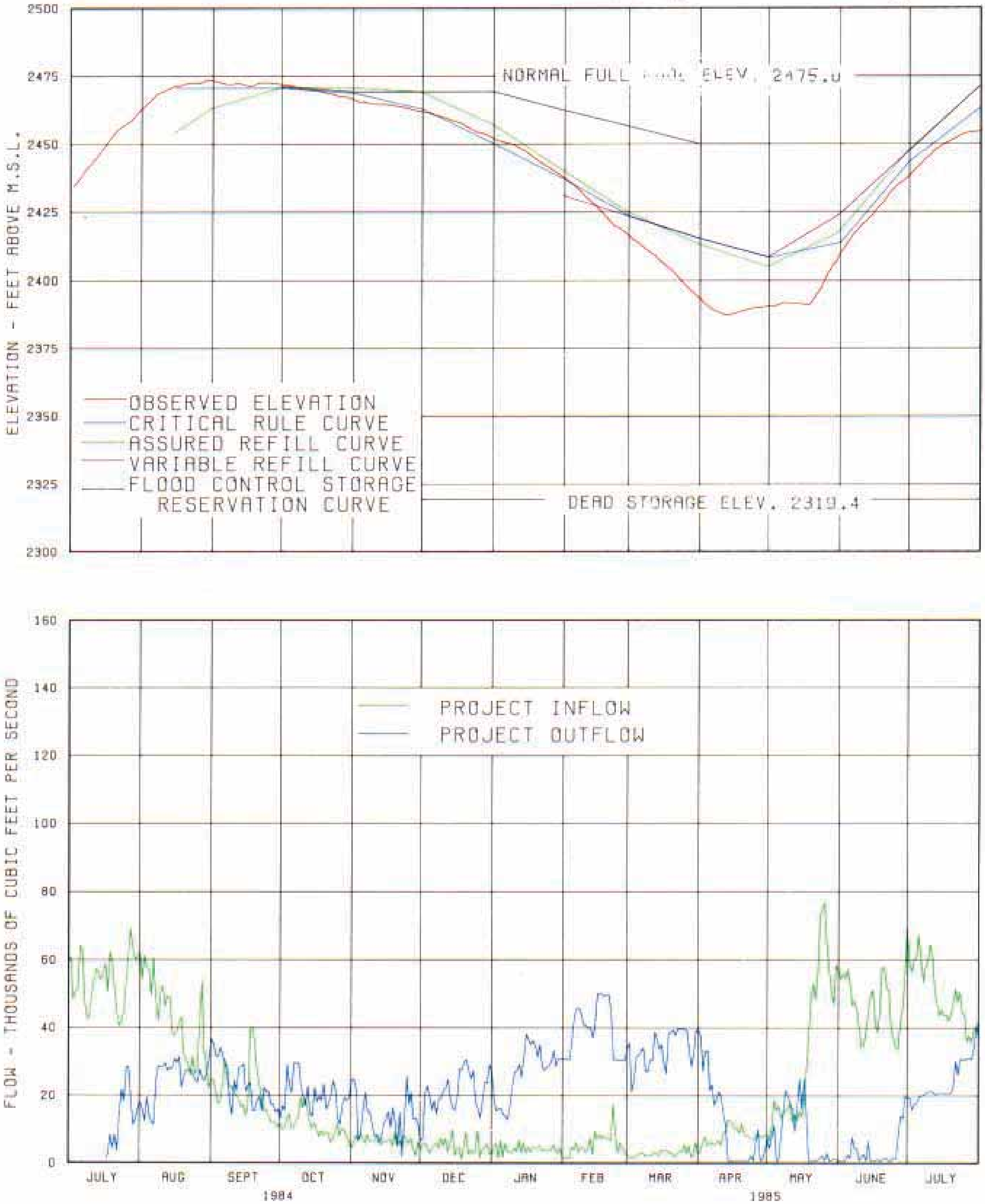
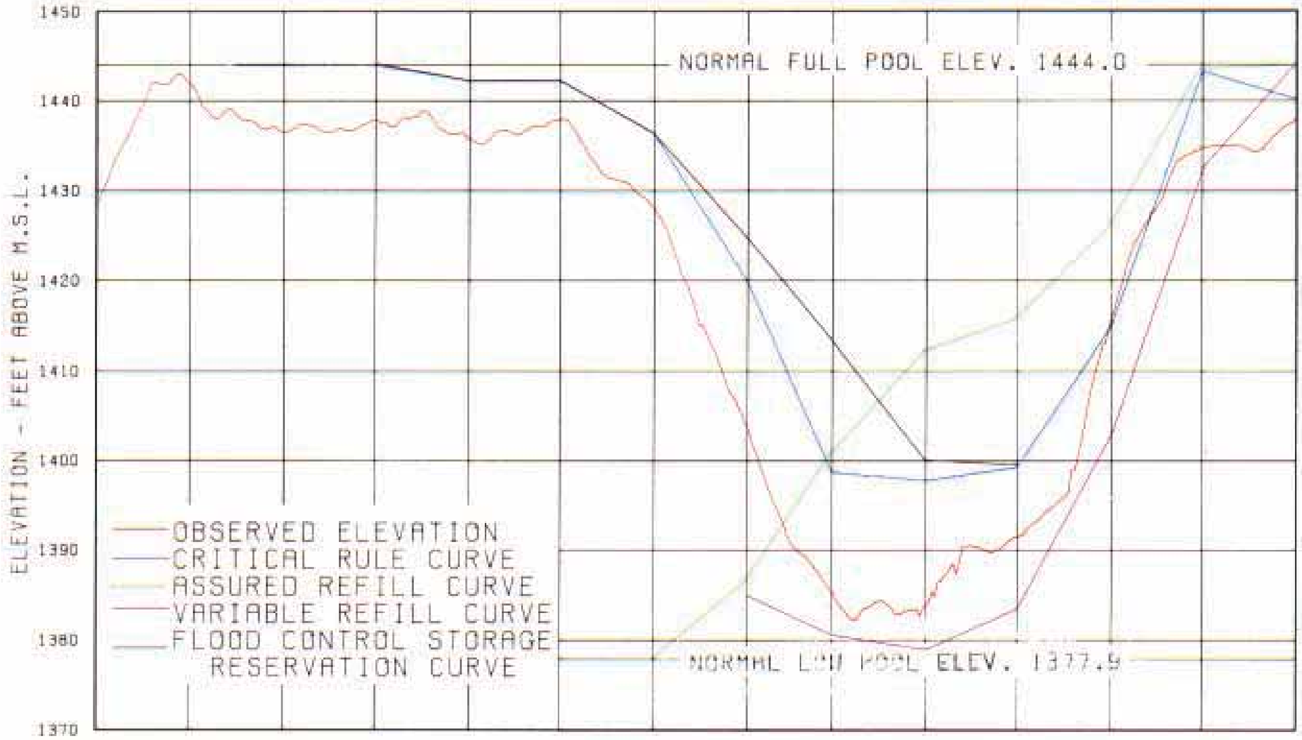


Chart 7

Regulation of Arrow 1 July 1984 — 31 July 1985



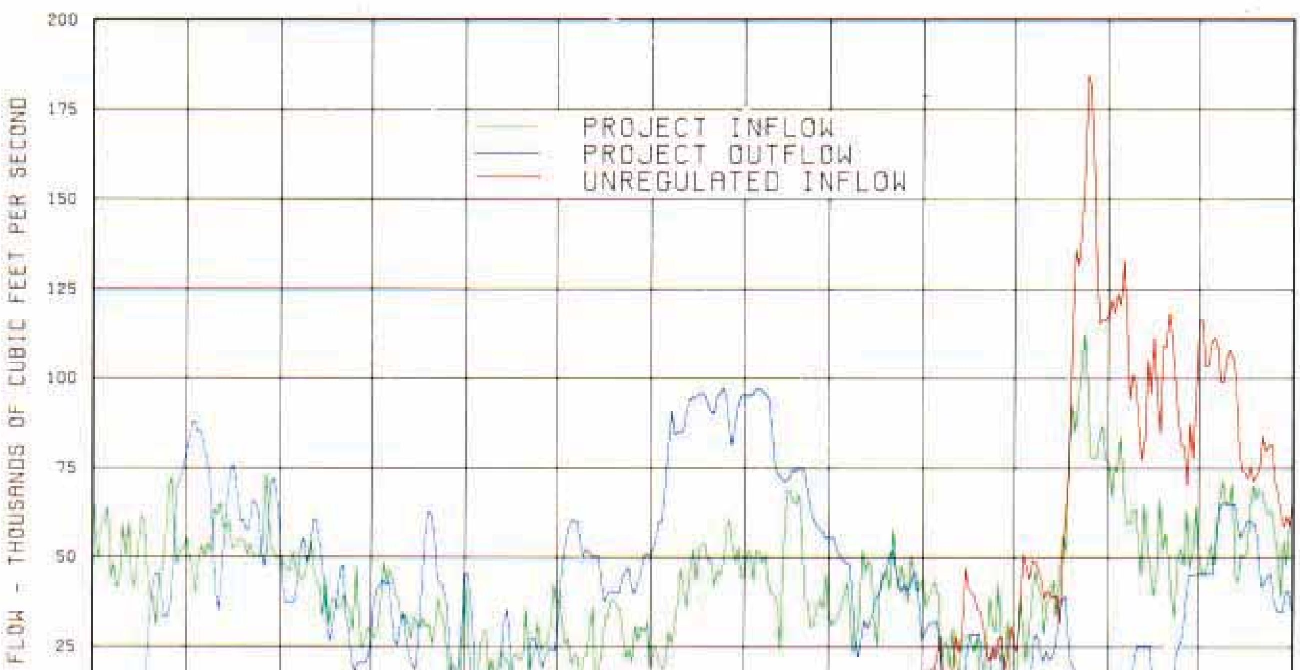
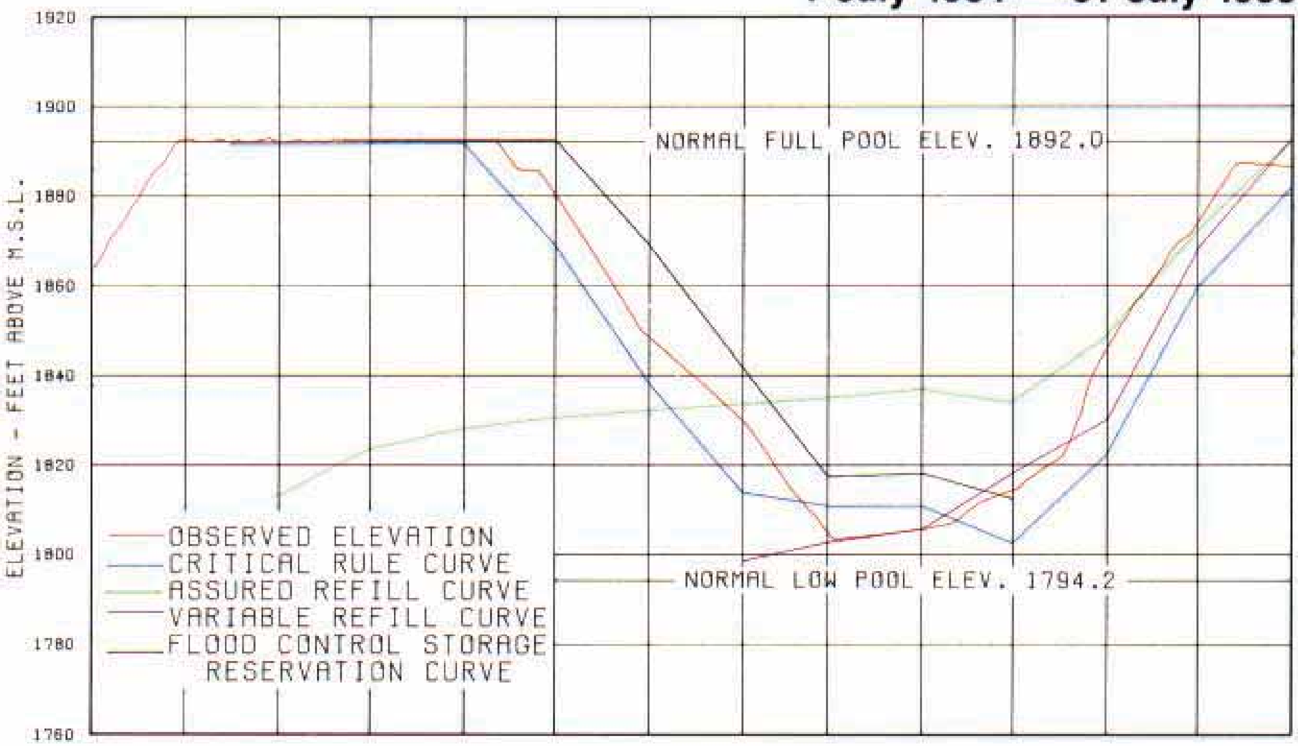


Chart 8
Regulation of Duncan
1 July 1984 — 31 July 1985



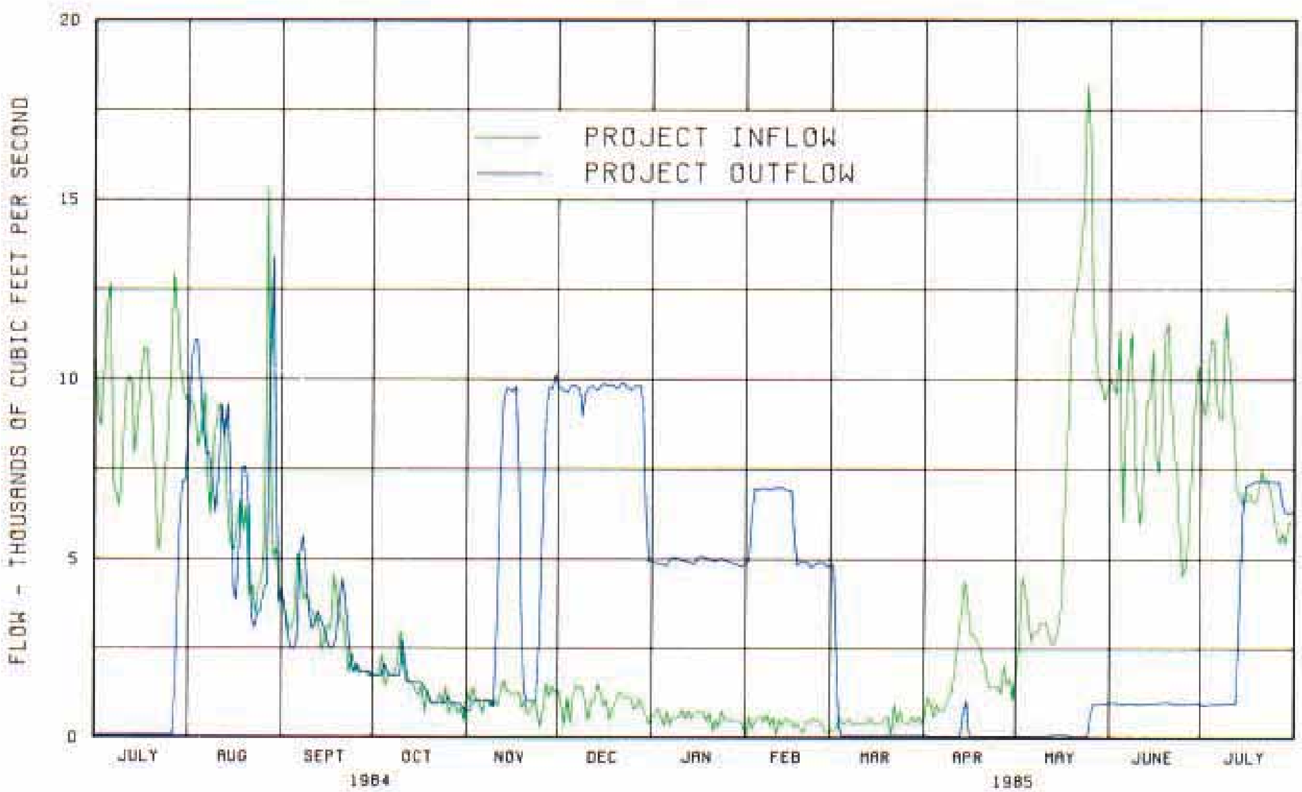
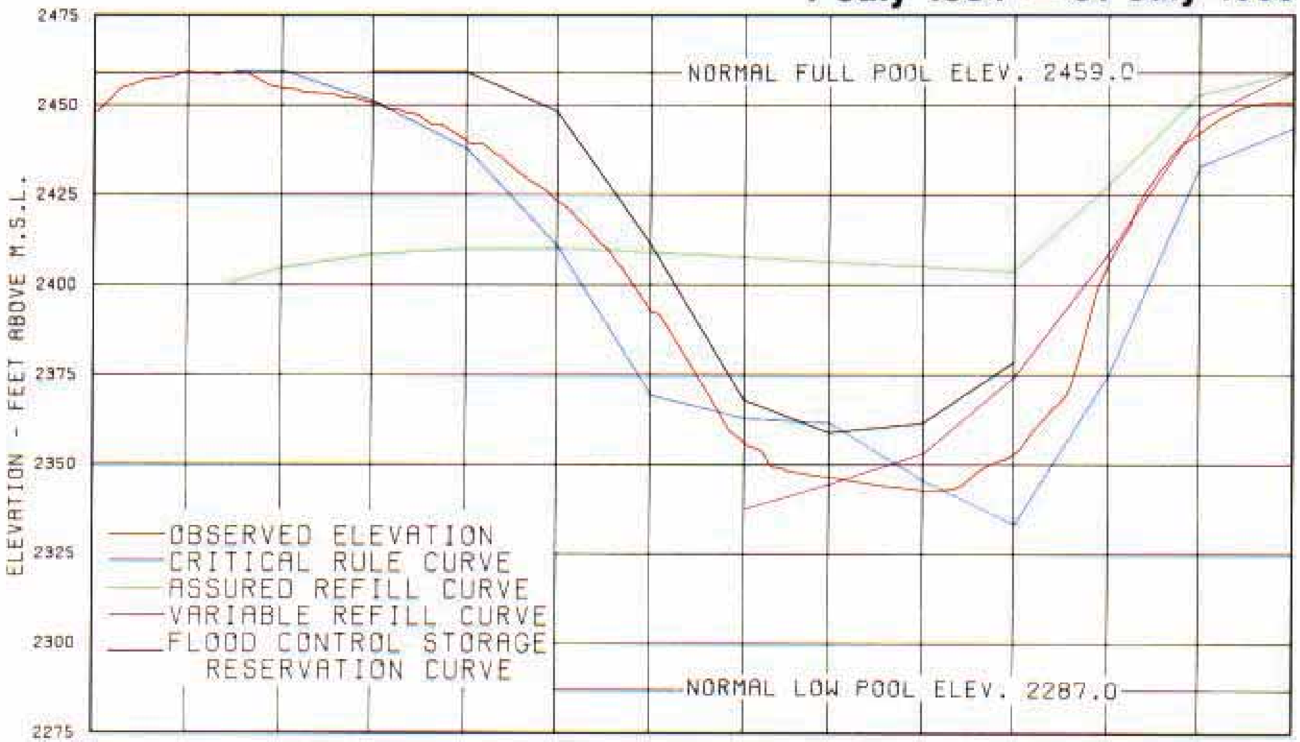


Chart 9

Regulation of Libby
1 July 1984 — 31 July 1985



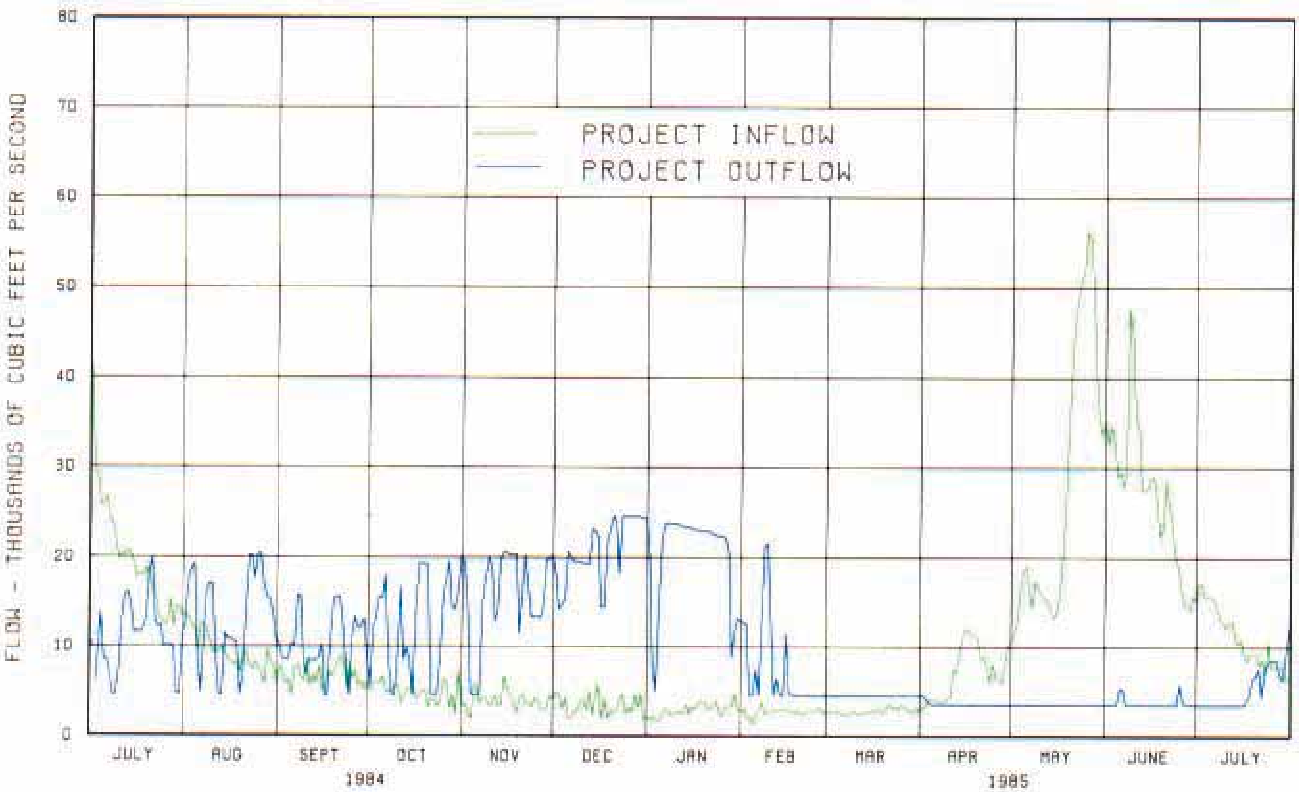


Chart 10

Regulation of Kootenay Lake
1 July 1984 — 31 July 1985

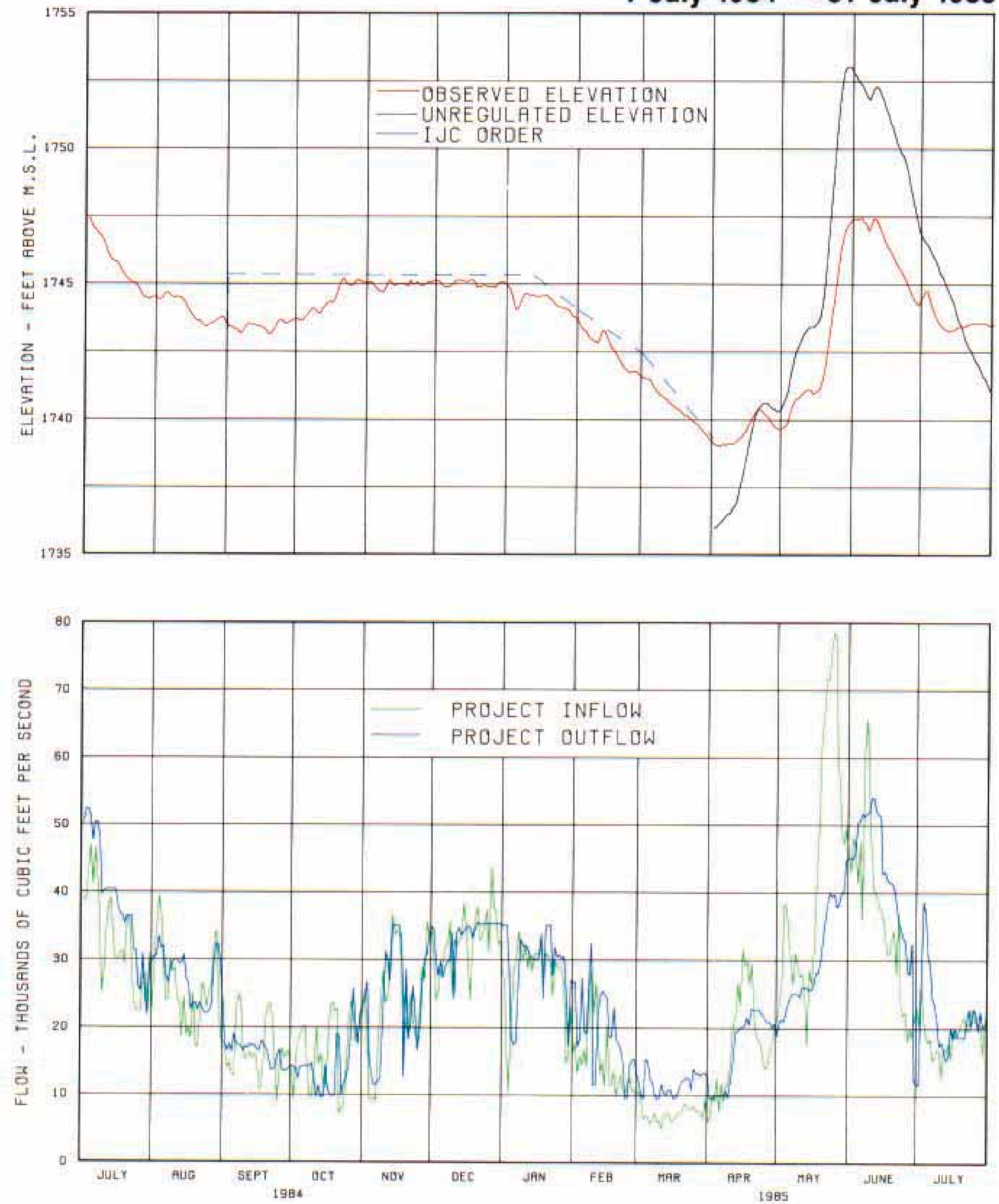


Chart 11

Columbia River at Birchbank
1 July 1984 — 31 July 1985

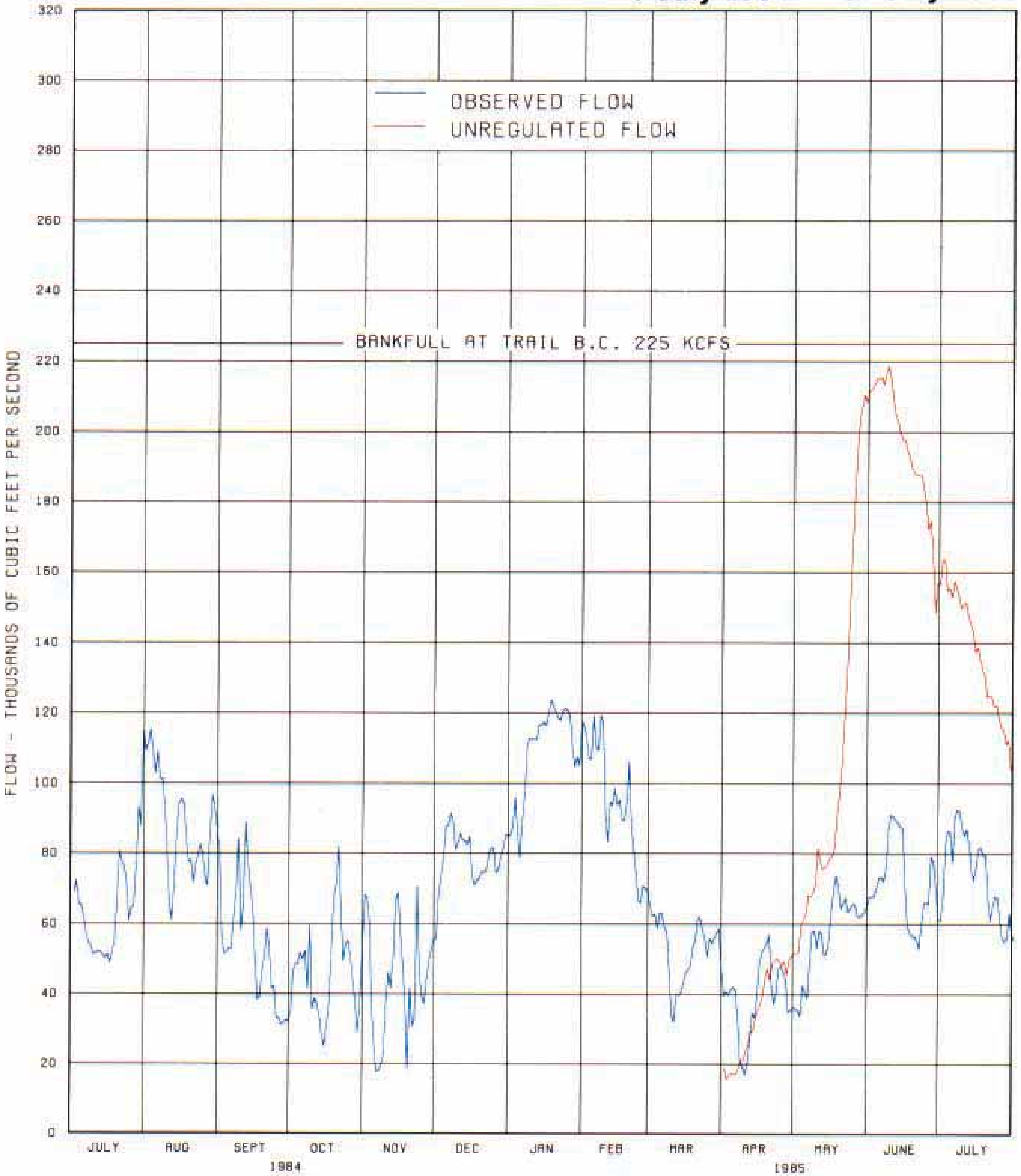


Chart 12

Regulation of Grand Coulee
1 July 1984 — 31 July 1985

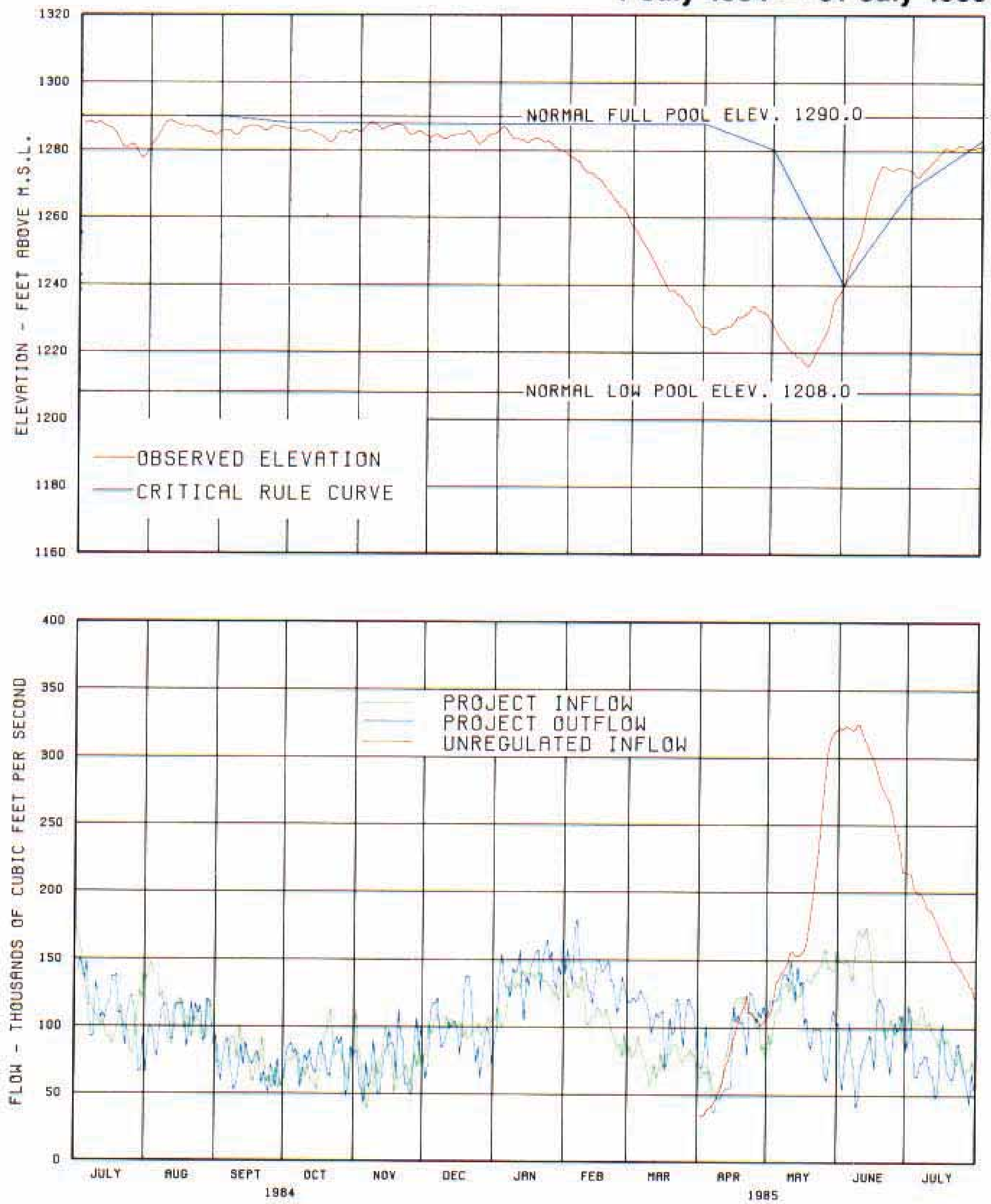


Chart 14

Columbia River at The Dalles
1 April 1985 — 31 July 1985

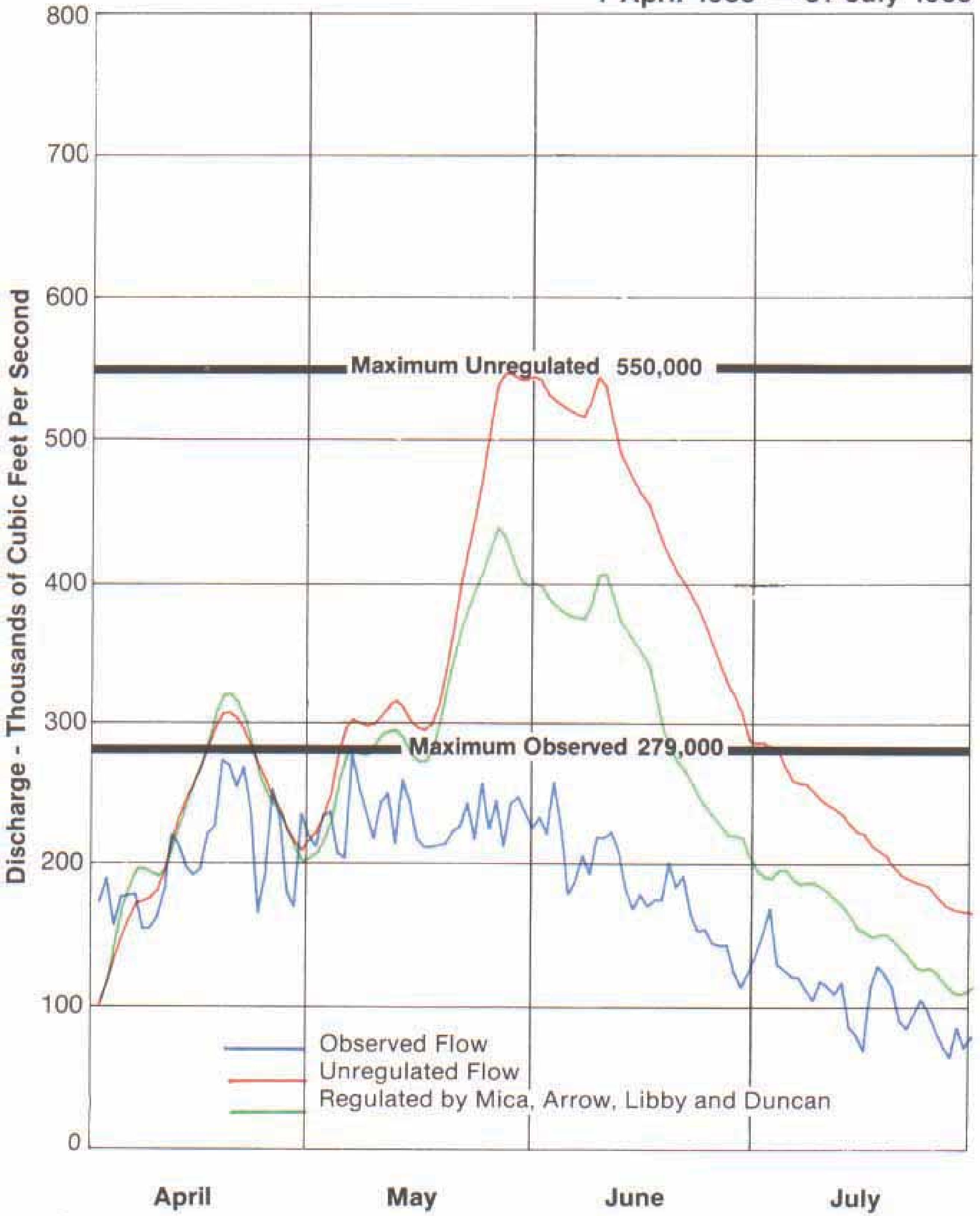


Chart 15

1985 Relative Filling
Arrow and Grand Coulee