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

1 October 1999 through
30 September 2000

November 2000

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

FOR THE PERIOD
OCTOBER 1, 1999 - SEPTEMBER 30, 2000

Executive Summary

General

The Canadian Treaty projects, Mica, Duncan, and Arrow, were operated during the reporting period according to the 1999-00 and 2000-01 Detailed Operating Plans, the October 1972 Flood Control Operating Plan and the revised October 1999 Flood Control Operating Plan, and several supplemental operating agreements described below. Throughout the year, Libby was operated according to the 1972 and 1999 Flood Control Operating Plans. During a portion of the year, Libby was operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). During the remainder of the year, Libby was operated according to the Biological Opinions (BiOp) as recommended by both the U.S. Fish and Wildlife Service (USFWS) and the U.S. National Marine Fisheries Service (NMFS), and according to supplemental operating agreements described below.

During the reporting period, the Entities agreed to a Libby Coordination Agreement (LCA) that resolved a five year dispute on compensation claims for the operation of Libby for nonpower purposes and the related impact on the Assured Operating Plans (AOP) and Determinations of Downstream Power Benefits (DDPB). As a result, the Entities were able to agree on the AOP/DDPB for the 2000-01, 2001-02, 2002-03, 2003-04, and 2004-05 operating years.

From 1 August 1999 through 31 July 2000, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Duncan and Arrow reservoirs to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amount returned, not including transmission losses and scheduling adjustments, was 306.8 average MW at rates up to 801.7 MW. No Entitlement power was disposed directly in the U.S. during 1 August 1999 through 31 July 2000, as was allowed by the 29 March 1999 Agreements on "Aspects of the Delivery of the Canadian Entitlement for April 1, 1998 through September 15, 2024" and "Disposals of the Canadian Entitlement within the U.S. for April 1, 1998 through September 15, 2024."

Entity Agreements

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

- Columbia River Treaty Entity Agreement Coordinating the Operation of the Libby Project with the Operation of Hydroelectric Plants on the Kootenay River and Elsewhere in Canada, signed 16 February 2000.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2000-01, signed 16 February 2000.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2001-02, signed 16 February 2000.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2002-03, signed 16 February 2000.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2003-04, signed 16 February 2000.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2004-05, signed 16 February 2000.
- Columbia River Treaty Entity Agreement to Study Various Alternatives for Shifting Columbia River Flows to Make Available Increased Amounts of Water in July and August, signed 31 May 2000.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2000, through 31 July 2001, signed 11 July 2000.

Operating Committee Agreements

Agreements approved by the Operating Committee include:

- Agreement on Implementation of the Arrow Local Method for Canadian Treaty Storage for Operating Year 1999-00, among the Columbia River Treaty Operating Committee, the Bonneville Power Administration, and the British Columbia Hydro and Power Authority, signed 23 December 1999.
- Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 2000, signed 22 December 1999.

- Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the Period 1 September 2000 through 30 April 2001, signed 23 August 2000.

System Operation

Under the 1999-00 Detailed Operating Plan (DOP), the Coordinated System operation is modeled similar to the Assured Operating Plan, without updated loads and U.S. fishery requirements. The Coordinated System operation under the DOP was essentially on Operating Rule Curve the entire year. No system wide proportional draft was required to meet established firm load carrying capability.

The 1 January 2000 water supply forecast for the Columbia River at the Dalles (January-July) was 105.0 million acre-feet (Maf), or 99 percent of the 1961-90 average. Precipitation was near average through April, when monthly average precipitation began to sag to below normal. The water supply forecast remained near normal through June until the low precipitation for May and June took its toll. The unregulated runoff from January through July was 98.0 Maf at The Dalles, only 93 percent of the 1961-90 average. The runoff in 2000 was very early, with the peak unregulated flow at The Dalles occurring in late April. The observed peak daily average flow observed at The Dalles was 375,100 cubic feet per second (cfs) on 23 April 2000.

The lower Columbia River flow was regulated for juvenile fish between 3 April and 31 August based on recommendations of the "Technical Management Team" (TMT) consisting of representatives from five U.S. Federal agencies. State fishery agencies and Indian tribes also provided input at the TMT meetings. This information was usually provided through the Fish Passage Center (FPC). The TMT's Policy and Technical groups make recommendations to the two operating agencies (USACE and Bureau of Reclamation) or the three Action Agencies (USACE, Bureau of Reclamation, and Bonneville Power Administration) on flow and operations to optimize passage conditions for juvenile and adult anadromous salmons in the lower Snake and Columbia Rivers in accordance with the National Marine Fisheries Service's 1995 Biological Opinion, the 1998 Supplemental Biological Opinion, and the 2000 Supplemental Biological Opinion (BiOp). The 1995 Biological Opinion also addresses operations recommended by the USFWS for sturgeon. Each year, the TMT also prepares a Water Management Plan to meet various fishery, flow, reservoir operation, and other objectives. The Biological Opinions recommend operations for thirteen listed fish species, and cover operations during each month of the year except September and October.

Treaty Project Operation

The Canadian Treaty projects, Duncan, Mica and Arrow, were operated throughout the year in accordance with the 1999-00 Detailed Operating Plan, the October 1972 Flood Control Operating Plan, and the revised October 1999 Flood Control Operating Plan, and the various Operating Committee Agreements. The Libby reservoir was operated in accordance with the 1999 Flood Control Operating Plan and the October 1972 Flood control Operating Plan throughout the period, and in accordance with the Libby Coordination Agreement, subsequent to its signing on 16 February 2000.

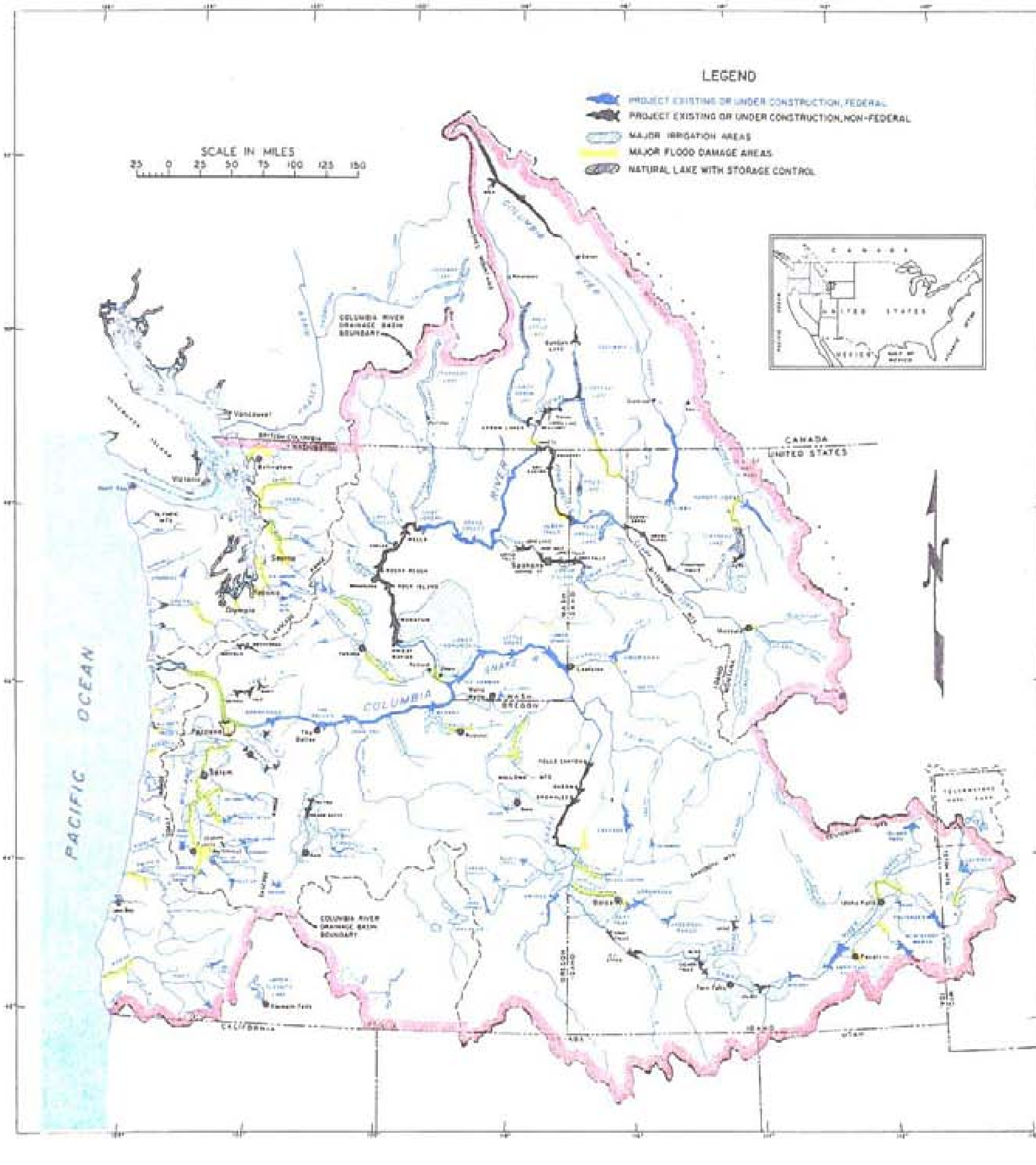
The Mica Treaty storage account was 6.7 million acre-feet (Maf) on 31 July 1999 and with continued impoundment reached 7.0 Maf or 100 percent full storage on 10 August 1999. The actual reservoir elevation reached a maximum of 2474.6 feet (0.4 feet below full) on 31 August 1999. By 31 December 1999, Treaty storage was drafted to 4.8 Maf, and the observed reservoir level had dropped to elevation 2434.2 feet. Treaty storage reached the lowest level for the year on 30 April 2000 at 0.46 Maf. The reservoir reached its lowest level for the 1999-2000 water year, elevation 2384.5 feet, on 27 April 2000. From then on, Mica Treaty storage refilled reaching 94 percent full at 6.6 Maf, on 31 July 2000. The maximum level for 2000 was elevation 2457.9 feet (17.1 feet below normal full pool), reached on 14 August 2000.

The Arrow Treaty storage account started the 1999-00 operating year 100 percent full at 7.1 Maf on 31 July 1999. The reservoir was drafted to elevation 1423.3 feet by 31 December 1999 with a Treaty storage of 5.8 Maf, or 81 percent of full. Arrow Reservoir reached its lowest level of the year at elevation 1393.8 feet on 4 April 2000. Arrow Treaty storage reached its annual minimum on 28 March 2000 at 0.99 Maf, or 14 percent of full. During the period 21 December 1999 to 17 January 2000, Arrow outflows were held between 50,000 cubic feet per second (cfs) and 55,000 cfs to maintain lower river levels during the whitefish spawning period. The Arrow Reservoir reached its lowest level for the 1999-2000 water year, elevation 1393.9 feet on 4 April 2000. During April and May 2000 outflows were held at about 20,000 cfs to ensure rainbow trout would not spawn immediately below Arrow, at high water levels. The reservoir reached its highest level on 25 July 2000 at elevation 1443.9 feet with the Treaty storage content reaching 100 percent full at 7.1 Maf on 2 August 2000.

Duncan reservoir elevation on 31 July 1999 was 1891.9 feet with Treaty storage filled to 99.8 percent of full capacity (1.4 Maf). The project passed inflow throughout August to maintain the reservoir near full pool. During September through December, Duncan was used to support the Kootenay Lake levels and increase Kootenay River flows. By 31 December 1999 the reservoir had drafted to 1866.8 feet. The reservoir continued to draft and reached its lowest level for the year at elevation 1794.3 feet on 1 April 2000. Minimum release during May to 22 July 2000 allowed the reservoir to refill reaching the full pool elevation of 1892.0 feet by 30 July 2000. Duncan passed inflow until 18 August 2000 before starting to draft to supplement flow into Kootenay Lake. The Duncan reservoir remained at or below the flood control curve throughout the operating year.

Libby reservoir on 31 July 1999 was at elevation 2456.9 feet, only 2.1 feet from full. Lake Koocanusa filled on 14 August 1999 and remained within the top five feet of full through August. Libby drafted to slightly below the 31 December 1999 flood control elevation at 2408.1 feet. Above average water supply forecasts, and above average inflow to Libby allowed the project to operate for flood control and its 95 percent confidence of refill curve at elevation 2436.2 feet on 15 April 2000. In May and June inflow dropped well below average to as low at 75 percent of average in June. In June 2000 the US Fish and Wildlife Service requested a sturgeon operation of 19 days at full powerhouse capacity near 25,000 cfs. During July through mid-September 2000 Libby was required to release a minimum flow of 8,000 cfs to enhance listed bull trout habitat downstream. The sturgeon and bull trout operations combined with below average inflow to Libby prevented the project from refilling. Lake Koocanusa reached its maximum elevation on 15 August 2000 at elevation 2436.33 feet, 22.67 feet below full, or 83 percent of full storage.

COLUMBIA RIVER AND COASTAL BASINS



2000 Report of the Columbia River Treaty Entities
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2000 Report of The Columbia River Treaty Entities
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I Introduction

This annual Columbia River Treaty Entity Report is for the 2000 Water Year, 1 October 1999 through 30 September 2000. 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 1999 through 31 July 2000. The power and flood control effects downstream in Canada and the United States are described. This report is the thirty-fourth 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 operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the United States of America. In 1964, the Canadian and the United States governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the Treaty. The Canadian Entity is the British Columbia Hydro and Power Authority (B.C. Hydro). The United States Entity is the Administrator of the Bonneville Power Administration (BPA) and the Division Engineer of the Northwestern Division, U.S. Army Corps of Engineers (USACE).

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 power benefits the U.S. base system 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 downstream power benefits 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 one half of the present worth of expected future 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. had the option (which it exercised) to construct Libby Dam with a reservoir that extends 42 miles into Canada and for which Canada agreed to make the land available.

7. Both Canada and the United States have the right to make diversions of water for consumptive uses. In addition, since September 1984 Canada has had 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 and U.S. Entities and Entity Coordinators) during the year on the morning of 16 February 2000 in Portland, Oregon. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY
Ms. Judith A. Johansen, Chair
Administrator & Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

Brigadier General Carl A. Strock, Member
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY
Mr. Brian R. D. Smith, Chair
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

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

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 (no longer in effect)
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.

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

Entity Coordinators & Secretaries

The Entities have appointed Coordinators from members of their respective staffs to help manage and coordinate Treaty related work, and Secretaries to serve as information focal points on all Treaty matters within their organizations.

The members are:

UNITED STATES ENTITY COORDINATORS
Gregory K. Delwiche, Coordinator
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

Michael B. White, Coordinator
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR
T. J. (Tim) Newton, Coordinator
Vice President, Strategic Planning
POWEREX
Vancouver, British Columbia

UNITED STATES ENTITY SECRETARY
Dr. Anthony G. White
Regional Coordination
Power and Operations Planning
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY SECRETARY
Douglas A. Robinson
Resource Management
Power Supply
B.C. Hydro and Power Authority
Burnaby, British Columbia

Columbia River Treaty Operating Committee

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

UNITED STATES SECTION
Richard M. Pendergrass, BPA, Co-Chair
William E. Branch, USACE, Co-Chair
Cynthia A. Henriksen, USACE
John M. Hyde, BPA

CANADIAN SECTION
Ralph D. Legge, B.C. Hydro, Chair
Kenneth R. Spafford, B.C. Hydro
Kelvin Ketchum, B.C. Hydro
Dr. Thomas K. Siu, B.C. Hydro

The Committee met six times during the reporting period to exchange information, review and discuss operating plans and issues, and approve work plans. The meetings were held every other month from September 1999 alternating between Canada and the U.S. The Committee also met numerous times to discuss and negotiate a proposal to resolve the Libby dispute. 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 have been prepared by the Committee with the assistance of others. During the period covered by this report, the Operating Committee negotiated the Libby Coordination Agreement, (which was agreed to by the Entities), coordinated changes to the Flood Control Operating Plan, and completed the 2004-05 Assured Operating Plan, the 1 August 2000 through 31 July 2001 Detailed Operating Plan (DOP), and several supplemental operating agreements. The Operating Committee also initiated studies analyzing the proposed Variable Q (flow) adjustments to Libby's flood control rule curves and the potential for increasing summer outflows from Canadian storage for U.S. flow augmentation. Also, during this period, the Operating Committee completed review of the USACE' revised Flood Control Operating Plan, dated October 1999. At the request of the Operating Committee the USACE' held a workshop on 6-8 June 2000 to discuss flood control procedures and the development of refill curves.

Operating Committee and support staff at the 27 July 2000 meeting at Libby Dam

Pictured from left to right: Bolyvong Tanovan (USACE); Tom Siu (B.C. Hydro, member); John Hyde (BPA, member); Kelvin Ketchum (B.C. Hydro, member); Ken Spafford (B.C. Hydro, member); Allen Woo (B.C. Hydro); Jim Gaspard (B.C. Hydro); Tim Newton (B.C. Hydro, coordinator); Rick Pendergrass (BPA, co-chair); Tony White (U.S. secretary); Bill Branch (USACE, co-chair); Cindy Henriksen (USACE, member); Ralph Legge (B.C. Hydro, chair); Doug Robinson (Canadian Secretary); Geri Mason (USACE); Tim Smith, (BPA); Julie Ammann (USACE); Mitzi Bauer (BPA).

Columbia River Treaty Hydrometeorological Committee

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

UNITED STATES SECTION	CANADIAN SECTION
Nancy L. Stephan, BPA Co-Chair	Eric Weiss, B.C. Hydro, Chair
Peter F. Brooks, USACE, Co-Chair	Don Druce, B.C. Hydro, Member

The only committee meeting (No. 46) for the year was hosted by BPA on 23 November 1999. There were seven attendees, including Harold Opitz who is the Hydrologist-in-Charge of the National Weather Service's Northwest River Forecast Center (NWSRFC).

Once again, a major part of the meeting dealt with the continuing issue of Treaty stations vs. Support stations as defined in the Terms of Reference for the Hydromet Committee. There were several conclusions which resulted from the discussion. Treaty stations would be defined as those used for the monitoring of the operations of Libby, Mica, Arrow, Duncan, Grand Coulee, and The Dalles. Support stations would include everything else used for both water supply and operational forecasts. With these definitions resolved, the committee will be sending a letter to the Permanent Engineering Board with the committee's interpretation of the definitions. This will clarify the definitions but the terms of reference will remain the same. In addition to clarifying the definitions, it was also decided that the committee would develop a list of current stations necessary for forecasting requirements, both operational forecasting and water supply forecasts. The primary purpose of the station list will be to make all users aware of the importance of these stations and to encourage their continued effort towards funding and operating those stations used for both treaty and support functions.

Other meeting topics included a review of the past year's reservoir operations, water supply forecasts, and weather. There was also a brief discussion on the upcoming Y2K event. Most agencies were implementing a freeze on any software changes until after the New Year. B.C. Hydro noted that this would impact their progress towards providing access for BPA and the NWSRFC to their File Transfer Protocol (FTP) site for direct retrieval of Canadian data. Since the meeting this effort has been successfully completed.

Once the general meeting topics were concluded, B.C. Hydro and BPA each provided a briefing on some key modeling and software being used in each group. Stephanie Smith provided an informative review of B.C. Hydro's new daily forecast model. She described the model's capabilities to allow adjustments and then rerun to generate new results. Ann McManamon, along with Harold Opitz, provided a demonstration of the National Weather Service Mountain Mapper software suite. The software uses underlying layers of elevation and mean monthly precipitation to estimate either observed data or forecast information in areas without observed or forecasted values. The software is used for quality checking data as well as converting point data into mean area values.

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
Stephen L. Stockton, Chair San Francisco, California Ronald H. Wilkerson, Member Missoula, Montana	Daniel R. Whelan, Chair Ottawa, Ontario Charles S. Kang, Member Victoria, British Columbia
Earl E. Eiker, Alternate nominee Washington, D.C. George E. Bell, Alternate Portland, Oregon	James Mattison, Alternate Victoria, British Columbia David E. Burpee, Alternate Ottawa, Ontario
Robert A. Bank, Secretary Washington, D.C.	David E. Burpee, Secretary Ottawa, Ontario

Under the Treaty, the PEB is to assemble records of flows of the Columbia River and the Kootenay River at the international boundary. It is also to report to both governments if there is deviation from the hydroelectric or flood control operating plans, and if appropriate, include recommendations for remedial action. Additionally, the PEB is to:

- 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;
- prepare 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, Operating Committee agreements, corrections to Hydrometeorological documents, and the annual Entity report to the Board for their review. The annual joint meeting of the PEB and the Entities was held on the morning of 16 February 2000 in Portland, Oregon, where the Entities briefed the PEB on the preparation and implementation of operating plans, the delivery of the Canadian Entitlement, and the resolution of a dispute over the operation of the Libby project.

PEB Engineering Committee

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

UNITED STATES SECTION
Robert A. Bank, Chair nominee
Washington, D.C.
Michael S. Cowan , Member
Lakewood, CO
Earl E. Eiker, Member
Washington, D.C.
James D. Barton, Member
Portland, OR
D. James Fodrea, Member
Boise, ID

CANADIAN SECTION
Roger S. McLaughlin, Chair
Victoria, British Columbia
Larry N. Adamache, Member
Vancouver, British Columbia
Myriam Boudreault, Member
Ottawa, Ontario
Dr. G. Bala Balachandran, Member
Victoria, British Columbia

The PEBCOM met with the Operating Committee on 26 October 1999 in Vancouver, British Columbia.

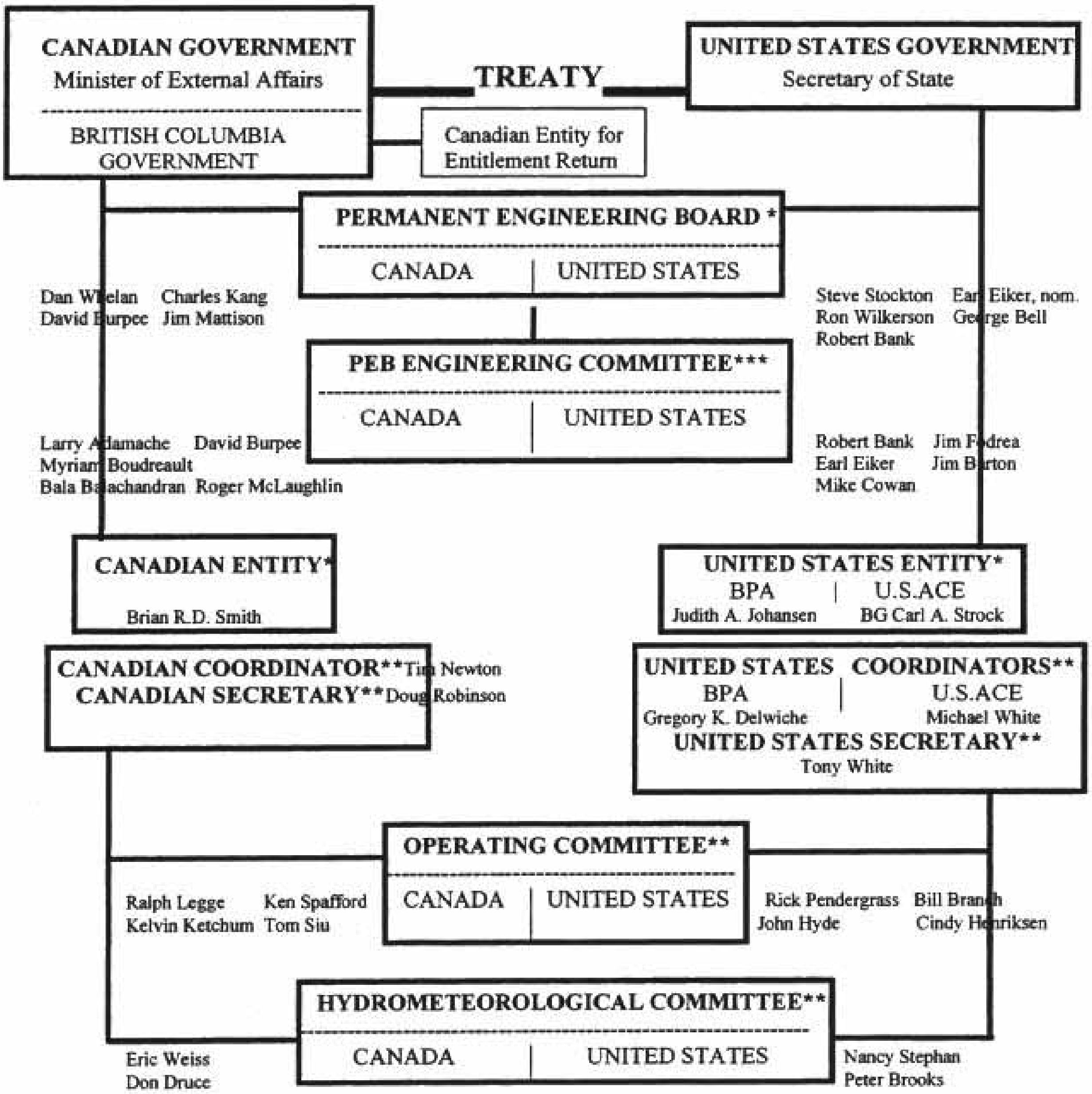
International Joint Commission

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 the Entities or the PEB cannot resolve a dispute concerning the Columbia River Treaty, that dispute may be referred to the IJC for resolution.

The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC informed. There are three such boards west of the continental divide. These are the International

Kootenay Lake Board of Control, the International Columbia River Board of Control, and the International Osoyoos Lake Board of Control. The Entities and the IJC Boards 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



* ESTABLISHED BY TREATY
** ESTABLISHED BY ENTITY
*** ESTABLISHED BY PEB

III Operating Arrangements

Power and Flood Control Operating Plans

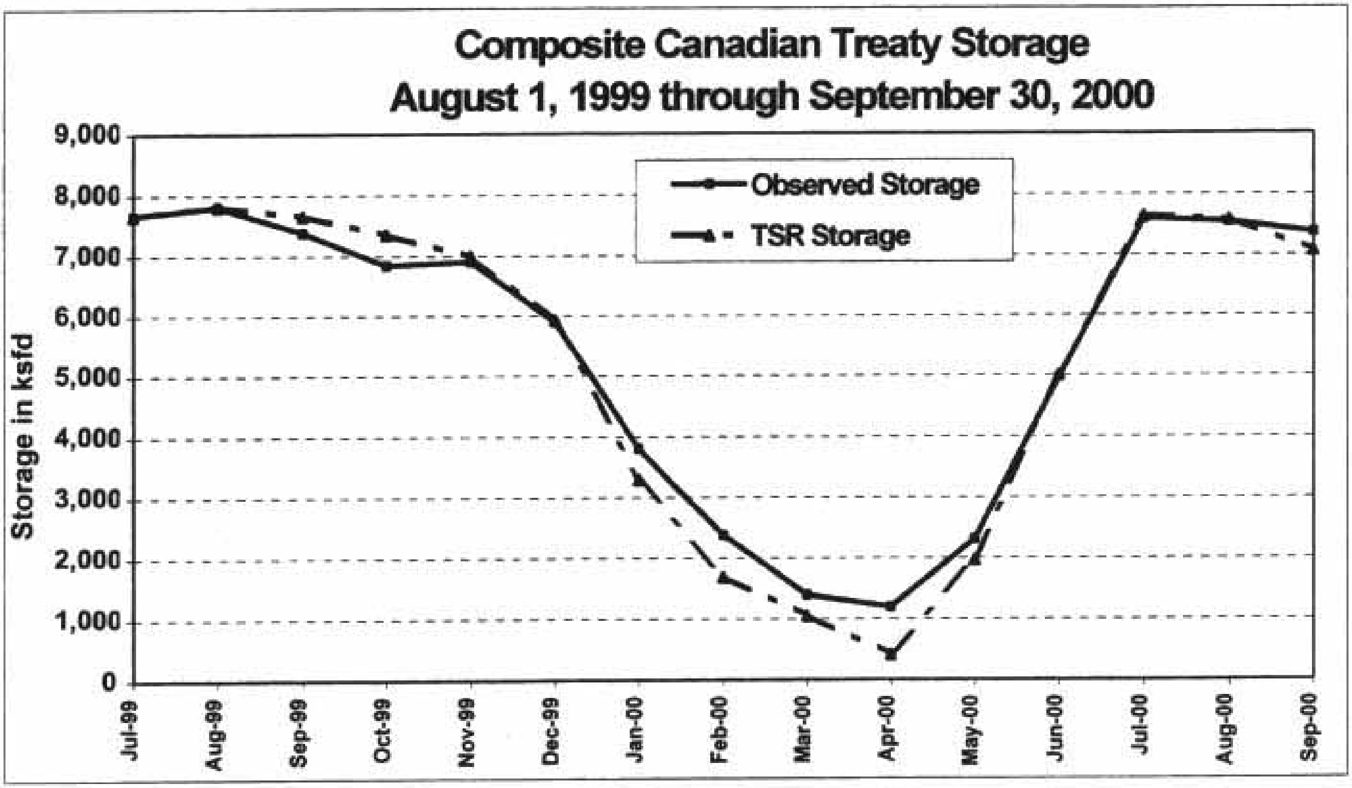
The Columbia River Treaty requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty stipulates that the United States Entity will submit flood control operating plans (FCOP). Annex A also says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

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans" dated December 1991 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1972, and the revised plan, dated October 1999, establish and explain the general criteria used to develop the DOP and operate Treaty storage during the period covered by this report. The flood control storage Reservation Diagram for Libby contained in the 1972 Flood Control Operating Plan, was amended by agreement of the Operating Committee to that contained in the USACE "Review of Flood control, Columbia River Basin, Columbia River & Tributaries Study, CRT-63, dated June 1991, and is included in the revised October 1999 Flood Control Operating Plan.

The planning and operation of Treaty Storage as discussed on the following pages is for the operating year, 1 August through 31 July. The operation of Treaty storage is determined by the Treaty Storage Regulation (TSR). The TSR is developed based upon the critical rule curves and Power Discharge Requirements for all projects in the Pacific Northwest that were developed for the 1999-00 Assured Operating Plan (AOP). The resultant rule curves for Canadian projects may be updated to be consistent with current requirements upon agreement of both Entities. The Canadian Storage operations in the TSR become input to the Pacific Northwest Coordination Agreement Actual Energy Regulation. The planning and operating for U.S. storage was accomplished according to the Pacific Northwest Coordination Agreement which now utilizes the same period. U.S. storage projects operate to the principles defined in the Pacific Northwest Coordination Agreement procedures and the resultant Actual

Energy Regulations (AER). Most of the hydrographs and reservoir charts in this report are for a thirteen-month period, July 1999 through July 2000.

The following chart compares the observed operation of the composite Canadian Treaty Storage to the results of the DOP Treaty Storage Regulation (TSR) study. The TSR was regulated to the Operating Rule Curve (ORC) during the entire period.



Assured Operating Plan

The Assured Operating Plans, dated November 1994 and February 2000, established Operating Rule Curves and other operating criteria for Duncan, Arrow, and Mica during the 1999-00 and 2000-01 operating years, respectively. The Operating Rule Curves provided guidelines for draft and refill. They were derived from Critical Rule Curves, Assured Refill Curves, Upper Rule Curves, and Variable Refill Curves, consistent with flood control requirements, as described in the 1991 Principles and Procedures document. The Flood Control Storage Reservation Curves were established to conform to the Flood Control Operating Plan of 1972, as amended and subsequently replaced in 1999.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits resulting from Canadian Treaty storage for the sixth succeeding year is made in conjunction with the Assured Operating Plan. For operating year 2000-01 the estimate of benefits resulting from operating plans designed to achieve optimum operation in both countries was not less than that which would have prevailed from an optimum operation in the United States only. The Entities agreed that, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement (CEPA), the United States was entitled to receive:

- 0.4 average megawatts of energy and no dependable capacity during the period 1 April 1999 through 31 March 2000, and

- No energy and no dependable capacity during the period 1 April 2000 through 31 March 2001.

  Suitable arrangements were made between BPA and B.C. Hydro for delivery of this energy, scheduled in accordance with the capacity provisions.

Return of Canadian Entitlement

Canadian Entitlement to downstream power benefits was sold to a nonprofit organization, the Columbia Storage Power Exchange, (CSPE, a consortium of 41 Northwest utilities), under a contract called the Canadian Entitlement Purchase Agreement (CEPA) for a period of thirty years following the Treaty-specified required completion date for each Canadian storage project. Purchase of Entitlement under CEPA expired 31 March 1998 for Duncan, and 31 March 1999 for Arrow, and will expire 31 March 2003 for Mica.

On 1 April 1998 Entitlement power began returning to Canada at the U.S.-Canada border, over existing power lines, as established by the 20 November 1996 Entity Agreement on Aspects of the Delivery of the Canadian Entitlement. For the period 1 August 1999 through 31 March 2000, the amount returned for Duncan and Arrow was 306.8 average megawatts of energy, scheduled at rates up to 802 megawatts. For the period 1 April 2000 through 31 September 2000, the amount returned for Duncan and Arrow was 277.4 average megawatts of energy, scheduled at rates up to 794 megawatts.

Detailed Operating Plan

During the period covered by this report, the Operating Committee used the 1 August 1999 through 31 July 2000 "Detailed Operating Plan for Columbia River Treaty Storage" (DOP), dated June 1999 and the 1 August 2000 through 31 July 2001, DOP, dated July 2000, to guide storage operations. These DOP's established criteria for determining the Operating Rule Curves, proportional draft points, and other operating data for use in actual operations. The DOP used AOP loads and resources, and AOP rule curves for both Canadian and U.S. projects to develop the Treaty Storage Regulation (TSR) study. The TSR study is updated twice monthly throughout the operating year, and together with any supplemental operating agreements, defines the end-of-month draft rights for Canadian storage. The Variable Refill Curves and flood control requirements subsequent to 1 January 2000 were determined on the basis of seasonal volume runoff forecasts during actual operation. The Operating Committee directed the regulation of the Canadian storage, on a weekly basis throughout the year, in accordance with the applicable DOP's and supplemental operating agreements made thereunder.

Entity Agreements

During the period covered by this report, eight joint U.S.-Canadian arrangements were approved by the Entities. The following tabulation indicates the date each of these were signed and gives a description of the agreement:

Date Agreement Signed by Entities	Description
16 February 2000	Columbia River Treaty Entity Agreement Coordinating the Operation of the Libby Project with the Operation of Hydroelectric Plants on the Kootenay River and elsewhere in Canada.
16 February 2000	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2000-01.
16 February 2000	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2001-02.
16 February 2000	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2002-03.

16 February 2000	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2003-04.
16 February 2000	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2004-05.
31 May 2000	Columbia River Treaty Entity Agreement to Study Various Alternatives for Shifting Columbia River Flows to Make Available Increased Amounts of Water in July and August.
11 July 2000	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2000 through 31 July 2001.

Operating Committee Agreements

During the period covered by this report, the Operating Committee approved four joint U.S. - Canadian agreements. The following tabulation indicates the dates they were signed, gives descriptions of the agreements, and cites the authority:

Date Agreement Signed by Committee	Description	Authority
22 December 1999	Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 2000	Detailed Operating Plan, 1 August 1999 through 31 July 2000, approved 24 June 1999 and dated July 1999
23 December 1999	Agreement on Implementation of the Arrow Local Method for Treaty Storage For Operating Year 1999-00 Among the Columbia River Treaty Operating Committee, the Bonneville Power Administration, and the British Columbia Hydro and Power Authority	Detailed Operating Plan, 1 August 1999 through 31 July 2000, approved 31 June 1999 and dated July 1999
23 August 2000	Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the Period 1 September 2000 through 30 April 2001	Detailed Operating Plan, 1 August 2000 through 31 July 2001, approved 11 July 2000 and dated July 2000

Non-Treaty Storage Letter Agreement

A letter agreement (Agreement) dated 3 March 2000 between B.C. Hydro and BPA confirmed discussions and arrangements regarding expected water storage and release transactions under the BCH-BPA Contract Number DE-MS798-90BP92754 (Non-Treaty Storage Agreement, or "NTSA") for the period 1 May 2000 through 31 August 2000. The Operating Committee, in accordance with that agreement, monitored the storage operations made under this Agreement to insure that they did not adversely impact operation of Treaty storage.

Long Term Non-Treaty Storage Contract

An Entity Agreement dated 9 July 1990 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, in accordance with that agreement, monitored the storage operations made under this Agreement throughout the operating year to insure that they did not adversely impact operation of Treaty storage.

IV Weather and Streamflow

Weather

In early August, 1999, a trough of low pressure off the California coast produced a moist southwest flow at mid levels of the atmosphere. Within this flow were weather disturbances which tracked northeast and helped to initiate scattered showers and thunderstorms, which were primarily focused across the higher terrain. In the middle of August, the jet stream lifted to the north in response to a building area of high pressure across the region. Intervals of light precipitation were reported across southern British Columbia. Dry and warmer weather prevailed elsewhere across the Pacific Northwest. A trough of low pressure brought unseasonably cool temperatures and unsettled conditions in late August. For August, precipitation was 131 percent of normal (1961-1990) at Columbia above Coulee; 101 percent of normal at the Snake River above Ice Harbor; and 122 percent of normal at Columbia above The Dalles.

In September 1999, a series of upper level disturbances brought light precipitation primarily to northern tier basins during the very beginning and end of the month. A ridge of high pressure maintained mainly dry weather during the remainder of the month. Chart 1 shows accumulated precipitation across the Columbia Basin during the October 1999 through the September 2000 water year. For September, precipitation was 47 percent of normal (1961-1990) at Columbia above Coulee; 23 percent of normal at the Snake River above Ice Harbor; and 34 percent of normal at Columbia above The Dalles. Chart 3 tracks the monthly precipitation and temperature departures above The Dalles during the winter period of September 1999 through March 2000.

In general, below normal precipitation and above normal temperatures were experienced for the southern half of the basin, near normal precipitation and below normal temperatures for the north. A ridge of high pressure dominated the basin early in October 1999 with minor disturbances progressing north into Canada. This pattern produced light precipitation and cold air in Canada, Idaho and Montana. A period of short lived southwesterly flow followed, bringing moderate rain to western Washington and light precipitation into northern Idaho and northwestern Montana. The mid and latter portions of the month were dominated by a ridge building into the south with minor disturbances brushing northwest Washington and Canada.

A cold front moved through western Montana on 2 and 3 October 1999 resulting in daily minimum temperature records. For October, precipitation was 129 percent of normal (1961-1990) at

Columbia above Coulee; 62 percent of normal at the Snake River above Ice Harbor; and 100 percent at Columbia above The Dalles. Early in November a slow moving flat ridge of high pressure dominated the basin weather picture. Generally dry weather exists during this period, with an exception to northwest basins, where a cold front brought light precipitation. By mid-month this flat ridge moved east of the Rockies and was replaced by a series of storm systems bringing bouts of precipitation mainly west of the Cascades.

During the latter portion of November 1999, a series of weather disturbances moving along a stalled frontal system tapped a rich supply of moisture originating from the subtropics. This combination of weather features produced moderate to locally heavy precipitation west of The Cascades and locally heavy precipitation across higher elevations east of The Cascades. A mild flow off the Pacific Ocean and lack of Arctic intrusions led to average temperatures ranging from 2 to 10 degrees above normal. For November, precipitation was 148 percent of normal (1961-1990) at Columbia above Coulee; 70 percent of normal at the Snake River above Ice Harbor; and 114 percent of normal at Columbia above The Dalles.

Frequent periods of light precipitation occurred in December 1999, which were focused mainly across west side basins as well as central and northern Idaho. Early in the month a series of frontal systems affected the region. During the end of the month, a strong ridge of high pressure maintained generally dry weather and near normal temperatures across the region. Temperature inversions and lack of significant mixing in lower levels of the atmosphere produced ideal conditions for persistent low clouds, fog, and patchy drizzle or snow flurries across some valley locations.

For December 1999, precipitation was 90 percent of normal (1961-1990) at Columbia above Coulee; 93 percent of normal at the Snake River above Ice harbor; and 93 percent at Columbia above The Dalles. Precipitation for the month of December was generally slightly below average except for pockets of above average precipitation in western Washington, in northeast Oregon and in the Clearwater basin in Idaho. The driest conditions were in southern Idaho and southern Oregon. Mountain snow as reported by the British Columbia Ministry of Environment and the Natural Resource Conservation Service was below average for most of the basin. The exceptions were British Columbia, Montana, northern Idaho and southwest Washington where above average 1 January snow conditions existed. The lowest 1 January snow conditions were in southern Oregon and southern Idaho where the snow pack was near 50 percent of average. Fall runoff had been above average in Washington, British Columbia and in the Clearwater River area in Idaho. The above average runoff in northern areas reflects more rainfall runoff due to above average temperatures and indicates that soil moisture storage in these areas will be above average.

The January 2000, 1st volume forecast for the January - July period at The Dalles is 105.million acre feet or 99 percent of average. This compares to a runoff of 124.1 million in 1999. Chart 2 depicts the Columbia Basin snowpack accumulation from January through May 2000. Water supplies in February improved for all Snake River tributaries, while in the northern portions of the basin water supply forecasts changed little from January. Precipitation during January was above average for most of Idaho and near average for the northern basins. Seasonal precipitation for the Columbia basin above The Dalles was at 104 percent of normal.

February 2000 began with a strong jet stream located along the southern periphery of a trough of low pressure across the Gulf of Alaska. This guided storm systems into the Pacific Northwest on a frequent basis. When systems were able to tap moisture from the subtropics, heavy precipitation was often the result, especially across the Olympic Peninsula, Cascades, and coastal range. Breaks in this overall weather pattern occurred for only a couple of days early in the month and again for a slightly longer period at the end of the month. During these hydrologically benign weather periods, high pressure maintained dry weather and high freezing levels.

For January 2000, precipitation was 100 percent of normal (1961 - 1990) at the Columbia above Coulee; 119 percent of normal at the Snake River above Ice Harbor; and 103 percent of normal at the Columbia above The Dalles.

It was a warmer and wetter than normal in February 2000. A split jet stream ushered a series of generally week low pressure systems into the northern and southern tiers of the basin early in February 2000. By mid month, and through the end of the month, the weather pattern shifted to a more zonal flow bringing rain to the basin valleys and snow to the mountains. Low pressure systems came onshore with frequency of every other day toward the later part of the month.

During February 2000, snow conditions for basins in most of Washington, northern Idaho, British Columbia and western Montana remained near to slightly below average. However, snow conditions in southern basins increased dramatically with increases of 20 - 50 percent from January 1st. Runoff for January was above average in the Upper Columbia and Kootenai and near to below average for the rest of the basin. The 1 February forecast for the January - July period at the Columbia River above The Dalles was 106 million acre feet or 100 percent of average, an increase of 1 percent from January. February precipitation was: 94 percent of normal (1961-1990) at Columbia above Coulee, 142 percent of normal at the Snake River above Ice Harbor, and 111 percent at Columbia above The Dalles.

Below normal precipitation was evident across much of the Pacific Northwest during March 2000. Notable exceptions included much of central and eastern Washington and Oregon as well as southern British Columbia, where precipitation was over 130 percent of normal in a few locations. Temperatures were above normal across much of Idaho and western Montana and near normal elsewhere east of the Cascades. West of the Cascades, temperatures were below normal.

Early in March 2000, a series of frontal systems brought abundant precipitation to western Washington and northwest Oregon. Precipitation was much lighter elsewhere across the region. During the middle of the month, precipitation started out being rather light as a cut off low pressure system developed across the desert southwest and the main storm track lifted north of the region. As this system lifted out of the southwest, a series of frontal systems once again began effecting the region. Moderate to locally heavy precipitation returned to western Washington, northwest Oregon, and higher elevations east of the Cascades. Late in the month, occasional showers occurred, especially across northern tier basins. Otherwise, a ridge of high pressure was fairly dominant through the latter part of the month. No temperature or precipitation records occurred in the month of March.

For March 2000, precipitation was: 111 percent of normal (1961-1990) at Columbia above Grand Coulee, 86 percent of normal at the Snake River above Ice Harbor, and 103 percent at Columbia above The Dalles. The 1 March snow conditions were somewhat below to near average for most of the basin. In the Upper Columbia-Kootenai, Pend Oreille and Spokane areas, snow accumulations during February were slightly below average while snow improved by 5 - 15 percent in other areas.

Above average temperatures and generally above average precipitation caused above average runoff for most of the Columbia River area above Grand Coulee, the Upper Snake and on western Oregon tributaries. Other areas had February runoff ranging from 70 to 85 percent of average. The March final runoff volumes in general decreased slightly on the Columbia River and increased by 5 - 15 percent on the Snake River. The January - July runoff for the Columbia River above The Dalles was at 105.0 million acre-feet or 99 percent of average. This was down 1 percent from February 1st.

During March 2000, snow water equivalent percentages increased slightly across northern portions of the basin and decreased 3-15 percent in the southern areas of the basin. The best improvements in snow pack occurred in the Upper Columbia, Kootenai and Flathead river basins, which are important contributors to the total flow on the Columbia River at The Dalles.

Volume forecasts improved slightly for the April 2000 final forecast for the Upper Columbia - Kootenai and the Flathead Rivers. The Snake River tributaries generally dropped 3 - 5 percent. This resulted in a January - July forecast for the Columbia River at The Dalles of 105 million acre feet or 99 percent of average.

During the beginning of April 2000, a ridge of high pressure along the West Coast was the dominant weather feature across the region. Dry conditions and unseasonably warm temperatures were common. During the middle of April, a couple of cut-off low pressure systems brought intervals of light to moderate precipitation, especially to southern tier basins. During the end of the month, a trough of low pressure deepened across the Gulf of Alaska. This allowed a series of weak frontal systems to impact the region. The most significant precipitation was reported across northern tier basins.

The snow water equivalent percentages decreased in most areas during the month of April 2000. This was caused by above normal temperatures for the month which marked the beginning of the snow runoff season. Chart 5 tracks the temperatures and precipitation departures during the April through August 2000 period above Grand Coulee. Only areas above Grand Coulee benefited from precipitation conditions which were normal to above normal. Chart 4 shows the April through July 2000 temperature and precipitation departures above The Dalles. Observed stream flow for April was above average for most of the Columbia Basin. Only areas in the Middle to Upper Snake experienced below normal runoff, but total runoff at Lower Granite was above normal. Volume forecasts for the Columbia above Grand Coulee were unchanged in May. Snake River tributaries generally dropped 1 - 5 percent. This resulted in a January - July forecast for the Columbia River at The Dalles to remain unchanged at 105 Maf or 99 percent of average.

During June 2000 temperatures were below normal across southern British Columbia and northern Washington, near normal across southern Washington, northern Oregon, northern Idaho and western Montana; and, above normal across southern Oregon, southern Idaho and northwest Wyoming. Precipitation was above normal west of the Cascades and across southern British Columbia, northwest Wyoming and extreme Southeast Idaho. Precipitation was near or below normal elsewhere across the Pacific Northwest. During the beginning and end of June, a trough of low pressure along the Pacific Northwest coast brought cool and showery conditions to the west-side and northern tier basins. During the middle of June, far southeast basins received precipitation from an upper level low pressure system which slowly tracked from the Gulf of Alaska into Northern California, then into the Great Basin.

Snow packs had depleted sharply basin wide by the beginning of June 2000. In northern areas the June 1st snow was about 70 percent of average, while southern portions of the basin had lost most of their snow. A reduced snow pack and slightly below average May precipitation caused a drop in the June final forecast volumes. Forecasts dropped 2-6 percent in most basins. The June 1st January - July forecast for the Columbia River at The Dalles is 102.0 Maf or 96 percent, down 3 percent from May.

Other than a few dry days early in the month, early and middle June 2000 was generally cool and unsettled. Moderate rain episodes were reported on a few days across the Olympic Peninsula. Otherwise, precipitation was mainly light and most prevalent across northern tier basins. During the end of June, a series of weak weather disturbances brought bouts of light rain to northern tier basins. The remainder of the region enjoyed mainly dry conditions with high pressure in control. The June accumulated precipitation across the basin was only 70 percent of normal in the Columbia River above Grand Coulee, 42 percent of normal at the Snake River above Ice Harbor, and 65 percent in the Columbia River above The Dalles.

Dry and near normal temperatures characterize most of the basin during the month of July 2000. Precipitation was generally light and primarily fell across the extreme north and south of the western portion of the basin in association with a series of weak weather disturbances. The East remained fairly dry under the influence of a high pressure system. July precipitation remained well below average with 77 percent of normal at Columbia above Grand Coulee, 45 percent of normal at the Snake River above Ice Harbor, and 74 percent at Columbia above The Dalles.

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 1999 through 31 July 2000, are shown on Charts 6 through 8. Chart 9 shows Libby hydrographs. 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 2000 period, including a plot of flows occurring if regulated only by the four Treaty reservoirs.

Composite operating year unregulated streamflows in the basin above The Dalles were below normal, and about 30 percent below last year's average streamflows. May was the high month during the spring runoff, being in the 89 percent of normal range. The August 1999 through July 2000 runoff for The Dalles was 136 Maf, 99 percent of the 1961-90 average. The peak regulated discharge for the Columbia River at The Dalles was 375,100 cfs on 23 April 2000. The 1999-00 monthly unregulated (natural) streamflows and their percent of the 1961-90 average monthly flows are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These flows have been corrected to exclude the effects of regulation provided by storage reservoirs.

	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Natural Flow	Percent of Average	Natural Flow	Percent of Average
Aug 99	151,790	135	196,010	142
Sep 99	106,550	134	93,860	98
Oct 99	91,140	120	81,740	95
Nov 99	99,410	129	138,090	151
Dec 99	122,240	149	110,330	117
Jan 00	130,250	147	90,230	92
Feb 00	110,850	133	114,320	102
Mar 00	98,620	119	141,390	100
Apr 00	123,610	123	286,300	128
May 00	149,820	88	377,360	89
Jun 00	148,280	67	376,360	76
Jul 00	125,180	79	236,760	92
Operating Year	121,480	109	186,900	99

Seasonal Runoff Forecasts and Volumes

Observed 2000 April through August runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume In 1000 Acre-Feet	Percent of 1961-90 Average
Libby Reservoir Inflow	5,499	86
Duncan Reservoir Inflow	2,060	100
Mica Reservoir Inflow	10,736	93
Arrow Reservoir Inflow	22,529	91
Columbia River at Birchbank	39,818	98
Grand Coulee Reservoir Inflow	57,927	95
Snake River at Lower Granite Dam	18,152	79
Columbia River at The Dalles	84,273	90

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2000 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 inflow volume forecasts for Mica, Arrow, Duncan, and Libby projects and for unregulated runoff for the Columbia River at The Dalles. Also shown in Table 1 page 43 are the actual volumes for these five locations. The forecasts for Mica, Arrow, and Duncan inflow were prepared by B.C. Hydro. The forecasts for the lower Columbia River and Libby inflows were prepared by the National Weather Service and River Forecast Center in cooperation with the USACE, National Resource Conservation Service, Bureau of Reclamation and B.C. Hydro. The 1 April 2000 forecast of January through July runoff for the Columbia River above The Dalles was 105.0 Maf and the actual observed runoff was 98.0 Maf.

The following tabulation summarizes monthly forecasts since 1970 of the January through July runoff for the Columbia River above The Dalles compared with the actual runoff measured in millions of acre-feet (Maf). The average January-July runoff for the 1961-1990 period is 105.9 Maf.

The Dalles Volume Runoff Forecasts in Maf (Jan-Jul)

Year	Jan	Feb	Mar	Apr	May	June	Actual
1970	82.5	99.5	93.4	94.3	95.1		95.7
1971	110.9	129.5	126.0	134.0	133.0	135.0	137.5
1972	110.1	128.0	138.7	146.1	146.0	146.0	151.7
1973	93.1	90.5	84.7	83.0	80.4	78.7	71.2
1974	123.0	140.0	146.0	149.0	147.0	147.0	156.3
1975	96.1	106.2	114.7	116.7	115.2	113.0	112.4
1976	113.0	116.0	121.0	124.0	124.0	124.0	122.8
1977	75.7	62.2	55.9	58.1	53.8	57.4	53.8
1978	120.0	114.0	108.0	101.0	104.0	105.0	105.6
1979	88.0	78.6	93.0	87.3	89.7	89.7	83.1
1980	88.9	88.9	88.9	89.7	90.6	97.7	95.8
1981	106.0	84.7	84.5	81.9	83.2	95.9	103.4
1982	110.0	120.0	126.0	130.0	131.0	128.0	129.9
1983	110.0	108.0	113.0	121.0	121.0	119.0	118.7
1984	113.0	103.0	97.6	102.0	107.0	114.0	119.1
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3
1987	88.9	81.9	78.0	80.0	76.7	75.8	76.5
1988	79.2	74.8	72.7	74.0	76.1	75.0	73.7
1989	101.0	102.0	94.2	99.5	98.6	96.9	90.6
1990	86.5	101.0	104.0	96.0	96.0	99.5	99.7
1991	116.0	110.0	107.0	106.0	106.0	104.0	107.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4
1993	92.6	86.5	77.3	76.6	81.9	86.1	88.0
1994	79.7	76.3	78.1	73.2	75.5	76.4	75.0
1995	101.0	99.6	94.3	99.6	99.6	97.9	104.0
1996	116.0	122.0	130.0	126.0	134.0	141.0	139.3
1997	138.0	145.0	142.0	149.0	153.0	159.0	159.0
1998	86.4	95.2	91.7	90.8	89.1	101.0	104.0
1999	116.0	119.0	130.0	128.0	124.0	123.0	124.1
2000	105.0	106.0	105.0	105.0	105.0	102.0	98.0

V Reservoir Operation

General

The 1999-2000 operating year began with near normal precipitation across the basin; however, unregulated inflow was well above average. These average conditions were reflected in the first official water supply forecast for the year 2000. The January final water supply forecast, which was developed during the first ten days of January and included precipitation through 31 December 1999, was 105 Maf at The Dalles for the January through July 2000 period. This was 99 percent of average for the period 1961-1990. Although precipitation remained slightly above normal, and inflow remained above normal, through April 2000, the water supply forecasts for the basin did not vary significantly, and remained near normal. By May and June of 2000 precipitation in the basin began to sag below normal. This was particularly evident in the northern tier of the basin above Grand Coulee. Although the May precipitation was below normal, the June final water supply forecast, which was developed in the first ten days of June, did not drop below average. Since the June 2000 precipitation was also far below normal, the July final forecast was below normal. The June 2000 final water supply forecast at Grand Coulee had dropped from 64.8 Maf (102 percent of 1961-90 normal) for the January through July period to 61.5 Maf (97 percent of normal) for the July final forecast. Similarly the June final water supply forecast for The Dalles for the January through July period was 103 Maf (97 percent of average) and the July final water supply forecast at The Dalles was 97.0 Maf (92 percent of normal).

During the 3 April-31 August 2000 salmon flow augmentation period, U.S. projects were used to augment flows at Lower Granite and McNary. The National Marine Fisheries Service's Biological Opinion, released in early March 1995, listed flow objectives flows that were variable based on runoff volume forecasts. The flow objectives were:

- Lower Granite, 85,000-100,000 cfs during 10 April - 20 June, and 50,000-55,000 cfs during 21 June-31 August.

- McNary, 220,000-260,000 cfs during 20 April - June 30, and 200,000 cfs during 1 July-31 August.

Provision for adjusting flow objectives based on runoff volume forecast was based on a sliding scale, such that in 2000 Lower Granite flow objectives were at 96,300 cfs for the period 3 April – 20 June and 51,300 cfs for the period 21 June – 31 August. The McNary spring objective was 260,000 cfs for the period 20 April – 30 June. The summer objective was set at 200,000 cfs and does not vary with runoff forecasts. In 2000 there was another flow objective to be met as defined in the National Marine Fisheries Service 1998 Supplemental Biological Opinion. This objective is measured at the Priest Rapids Dam in the mid-Columbia River. The objective is 135,000 cfs for the period 10 April through 30 June. It does not vary based upon the water supply forecast.

The computation of the flow objectives at Lower Granite are based on the May final water supply forecast, which was 19.0 Maf at Lower Granite for the April through July period, which is 88 percent of average. The spring flow objective at McNary was based on the May final water supply forecast of 105.0 Maf at the Dalles for the January through July period. The seasonal flow objectives at Lower Granite were not met for either spring or summer of 2000. The observed outflow at Lower Granite for the period 3 April through 20 June was 85,000 cfs and 21 June to 31 August was 35,000 cfs. At McNary the seasonal flow objectives were not met either. The average observed outflow for the period 20 April through 30 June was 243,000 cfs, and the observed flow from 1 July through 31 August was 156,000 cfs. The spring flow objective at Priest Rapids was exceeded in 2000. The observed flow for the spring period of 10 April through 30 June was 157,000 cfs. Since the water supply forecast for the lower Snake River above Lower Granite was far below average (about 90 percent of normal), it could not meet the high flow recommended in the Biological Opinions. When the objectives were not met at Lower Granite, this contributed to the low flow at McNary, and thus both sites did not meet flow objectives.

Another contributing factor to this phenomenon was a very early runoff. The peak unregulated flow was in late April. As natural flow did not increase as normally expected high flow was maintained at both Lower Granite and McNary in early May. This used the storage resources for flow augmentation and contributed to not refilling at all U.S. storage projects. Since the U.S. storage projects did not refill by 30 June 2000, there was not maximum storage available to meet summer flow in July and August. This contributed to further reductions in the summer observed flow for fish.

Canadian Treaty Storage Operation

As specified in the DOP, the release of Canadian Treaty storage is made effective at the Canadian-United States border. Accordingly, releases from individual Canadian projects can vary from the release required by the DOP (TSR plus supplemental operating agreements) so long as this variance does not impact the ability of the Canadian system to deliver the sum of Treaty outflows from Arrow and Duncan reservoirs. Variances from the DOP storage operation are accumulated in respective Flex accounts. An overrun in an account occurs when actual project releases are greater (contents are lower) than those specified by the DOP. Conversely, an underrun occurs when actual project releases are less (contents are higher) than those specified by the DOP. Flex accounts for Mica, Revelstoke, Arrow, and Duncan are balanced at any point in time to ensure that under/overruns do not impact the total Treaty release required at the Canadian-United States border The terms under/overrun are used in the description of Mica Reservoir operations below.

Mica Reservoir

As shown in Chart 6, the Mica Reservoir (Kinbasket Lake) level was at elevation 2461.4 feet on 31 July 1999, 13.6 feet below full pool elevation of 2475 feet. The corresponding Mica Treaty storage account was 95 percent of full at 3369.4 ksfd (6.7 Maf) on that date.

The local inflows into Mica reservoir averaged about 54,600 cfs in August, reducing to 20,000 cfs in September and about 6,900 cfs by the end of December 1999. Mica Treaty storage continued to fill during August, reaching full storage of 3529.2 ksfd (7.0 Maf) on 10 August 1999. The Mica Reservoir started to draft in early September as turbine discharges exceeded inflows. The Mica Treaty underrun of 420 ksfd on 31 August was reduced in September, reaching a minimum of 17.3 ksfd on 17 November increasing again with a year end underrun at 634 ksfd on 31 December 1999.

Actual Mica discharges increased through August 1999 and averaged 75 percent of the maximum turbine capacity. This corresponded to an average discharge of about 32,000 cfs in August. The September and October discharge averaged 36,100 cfs and 35,800 cfs, respectively. In November, the average Mica discharge was 25,000 cfs and in December, 17,800 cfs. The reservoir drafted 8.8 feet in September, 15.6 feet in October, 7.5 feet in November and 7.2 feet in December reaching an elevation of 2434.2 feet by calendar year end. At that time, the B.C. Hydro Non-Treaty Storage was about 393 ksfd, or 35 percent of full, with Treaty storage at 2514.4 ksfd (about 5.0 Maf), or 71 percent of full.

In early January, February, and March 2000, the inflows averaged about 4,800 cfs for each month, gradually increasing in April to 7,500 cfs before the start of the spring freshet in May. Mica powerhouse discharges for January and February averaged around 33,000 cfs for each month with Mica generation decreasing over the rest of winter 2000. The reservoir drafted by about 120 feet during the period to elevation 2394.8 feet by 29 February with Treaty Storage at 1395.2 ksfd and Mica Treaty overrun of about 280 ksfd on that date. The B.C. Hydro NTSA was at 416.9 ksfd at the end of February. During March and April, the Mica Reservoir was drafted an additional 10 feet and reached its lowest level for the 1999-00 year of 2384.5 feet on 27 April 2000, 11.0 feet higher than the low level in the previous year. Mica Treaty storage was drafted to its minimum of 231.6 ksfd (0.4 Maf) on 30 April with a Mica flex overrun of about 69 ksfd.

In March and April, the Mica turbine discharges averaged 14,500 and 9,700 cfs, respectively with an average of about 9,000 cfs in May and 12,000 cfs in June 2000. The corresponding plant generation was 34 percent and 22 percent, respectively of plant capacity during March and April. With the start of the spring freshet in May, Mica discharges remained low until July, and the reservoir refilled by 35 feet to elevation 2419.9 feet at the end of June. At the end of May, the Mica Treaty underrun (definition of underrun and overrun see Canadian Treaty Storage Operation first paragraph) had increased to 198 ksfd. The Mica Treaty discharge was 10 kcfs for the months of May, June and July, allowing Treaty storage to refill to 3330.9 ksfd (6.6 Maf; 94 percent of full) by 31 July. Inflows increased in May, June and July averaging about 21,000, 45,000 and 63,000 cfs, respectively. Actual Mica discharges during May, June and July averaged 9,000, 12,000 and 15,000 cfs resulting in a Mica Treaty overrun of 22 ksfd and a reservoir elevation of 2451.3 feet by the end of July 2000. The corresponding plant generation was about 35 percent of plant capacity in July 2000. The August inflows averaged about 37,000 cfs but had receded to about 21,000 cfs by month end. The Mica Treaty storage reached full at 3529.2 ksfd on 15 August 2000 with the reservoir at elevation 2457.8 feet, 17.0 feet below full pool. The Mica reservoir elevation on 31 August 2000 was 2455.2 feet (about 20 feet from full pool).

Revelstoke Reservoir

During the 1999-00 operating year, the Revelstoke project was operated as a run-of-river plant with the reservoir level maintained generally within 3.0 feet of its normal full pool elevation of 1880 feet. During the spring freshet, March through July, the reservoir operated as low as elevation 1876.5 feet, within its maximum draft range of 5.0 feet, to provide additional operational space to control high local inflows. Changes in Revelstoke storage levels did not affect Treaty storage operations.

Arrow Reservoir

As shown in Chart 7, the Arrow Reservoir reached its maximum actual elevation of 1443.8 feet on 31 July with the Arrow Treaty storage reaching 100 percent full on 1 August 1999. The reservoir drafted through August and September and reached elevation 1432.4 feet by the end of September. The Arrow Treaty storage was 6.4 Maf or 90 percent full at the end of September.

Arrow discharges decreased over the autumn months from an average of 62,000 cfs in September to 46,000 cfs in October and 44,000 cfs in November. The discharge increased to an average of 56,000 cfs in December. Average inflows were 51,000 cfs in September, 46,000 cfs in October dropping to 28,000 cfs by December 1999. The Arrow Reservoir drafted to elevation 1423.3 feet by 31 December 1999 with the Treaty storage at 2916 ksfd (5.8 Maf) or 81 percent of full on that date.

During the period 21 December 1999 to 17 January 2000, Arrow outflows were reduced to between 50,000 cfs and 55,000 cfs to maintain lower river levels during the whitefish spawning period that could be sustained through the period of emergence in February and March. To achieve the January level of flows, B.C. Hydro exercised an option to store up to 400 ksfd under the Whitefish Provisional Draft Agreement over the first 16 days of January. During the latter part of January, outflows from Arrow averaged about 73,000 cfs, decreasing in February to 51,000 cfs, and then reducing to about 40,000 cfs in March. Between 21 March to 29 March 1999, the outflows from Arrow were progressively reduced from 45,000 cfs to 20,000 cfs and continued at that level through April and May to meet objectives for rainbow trout spawning. In exchange for the rainbow trout protection flows in the spring, the U.S. exercised an option, under the Non-Power Uses agreement signed in December, to store up to 1 Maf in Arrow by late April 2000 for Flow Augmentation objectives. The Flow Augmentation storage was subsequently released during May.

In this operating year, the Columbia River Treaty Operating Committee agreed to use the Arrow Local Method for determining the Mica and Arrow Variable Refill Curves between January and June 2000. Compared to the Total Method, the Arrow Local Method recognizes Mica outflows in excess of those from operating Mica to the Variable Refill Curve (VRC) when computing Arrow's VRC, and on average, results in lower VRC's at Arrow during January through April. In both cases, the Arrow reservoir is targeted to be full on 31 July. The Arrow Local Agreement was signed in December 1999, with the expectation that power benefits realized in excess of those expected by the Total Method would be shared equally between BPA and B.C. Hydro. Multi-year TSR studies have indicated that the expected power benefits occur during average-to-low water conditions. However, because of the unusually high relative energy prices during the summer as compared to the winter of year 2000 there were no power benefits realized.

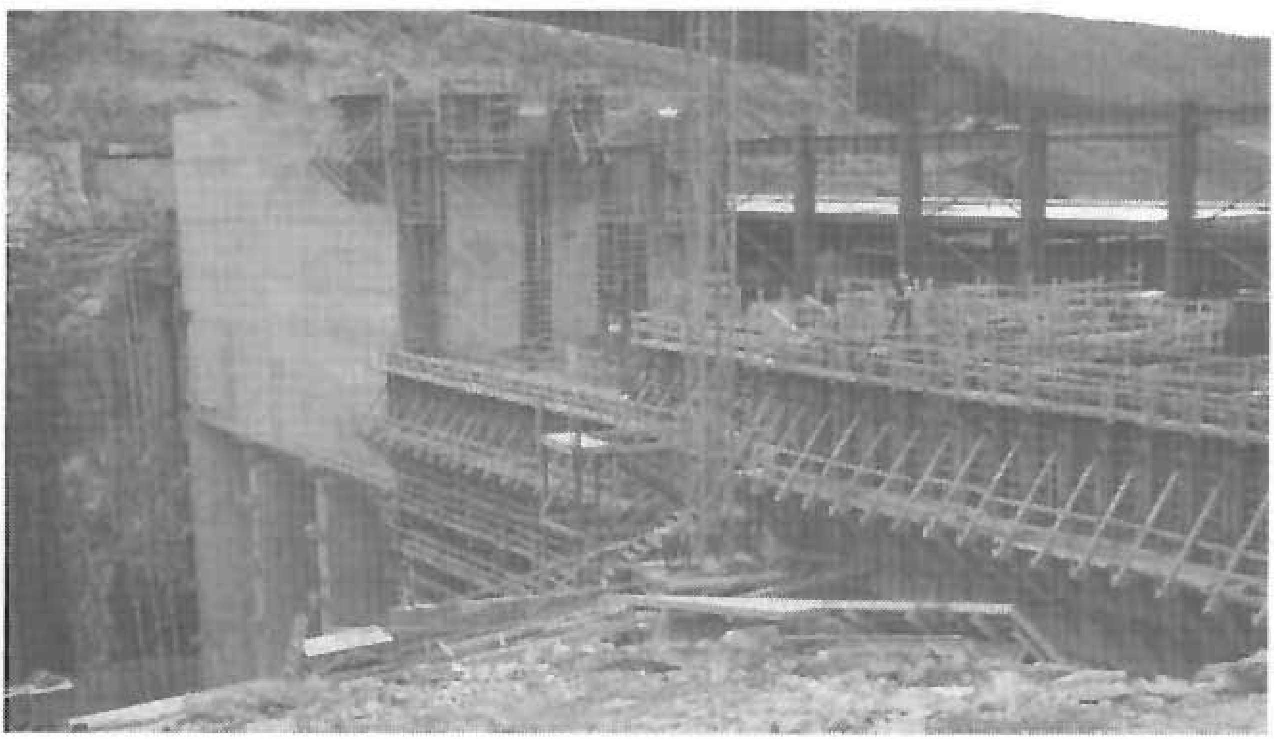
Arrow Reservoir reached its lowest level for the year at 1393.9 feet on 4 April 2000. Arrow Treaty storage account reached its minimum at 502 ksfd (0.99 Maf) or 14 percent of full on 28 March 2000. During April and May, the Arrow discharge was maintained at about 20,000 cfs to prevent rainbow trout spawning at higher river levels. Arrow discharge was maintained above 20,000 cfs until 20 June 2000. During the last 10 days of June flows were reduced to 14,000 cfs when the backwater effects of higher Kootenay River flows provided adequate river levels for rainbow trout protection at Norns Creek Fan, a prime spawning location for rainbow trout.

The Arrow fisheries operations were conducted under the terms of two Operating Committee agreements, "Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the period of 1 September 1999 through 30 April 2000" and "Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 2000". These agreements enabled the Arrow project flows to be adjusted to reduce impacts to whitefish and rainbow trout redds. With the low discharge in April and May, and the start of the spring freshet with high inflows in May, the Arrow Reservoir rose to elevation 1398.4 feet by 30 April, 1414.6 feet by 31 May, and 1435.8 feet by 30 June 2000. Arrow reservoir levels remained below the Treaty flood control curve levels throughout the operating year.

The Arrow discharge was increased substantially in July as Arrow Treaty storage neared full and the reservoir reached its highest elevation, 1443.9 feet, on 25 July 2000. The Arrow Treaty storage content reached full (7.1 Maf) on 2 August 2000. The Coordinated Columbia System was on proportional draft during August 2000. As a result, Arrow Treaty storage was drafted to 3346 ksfd, (6.6 Maf: 94 percent of full) at the end of August.

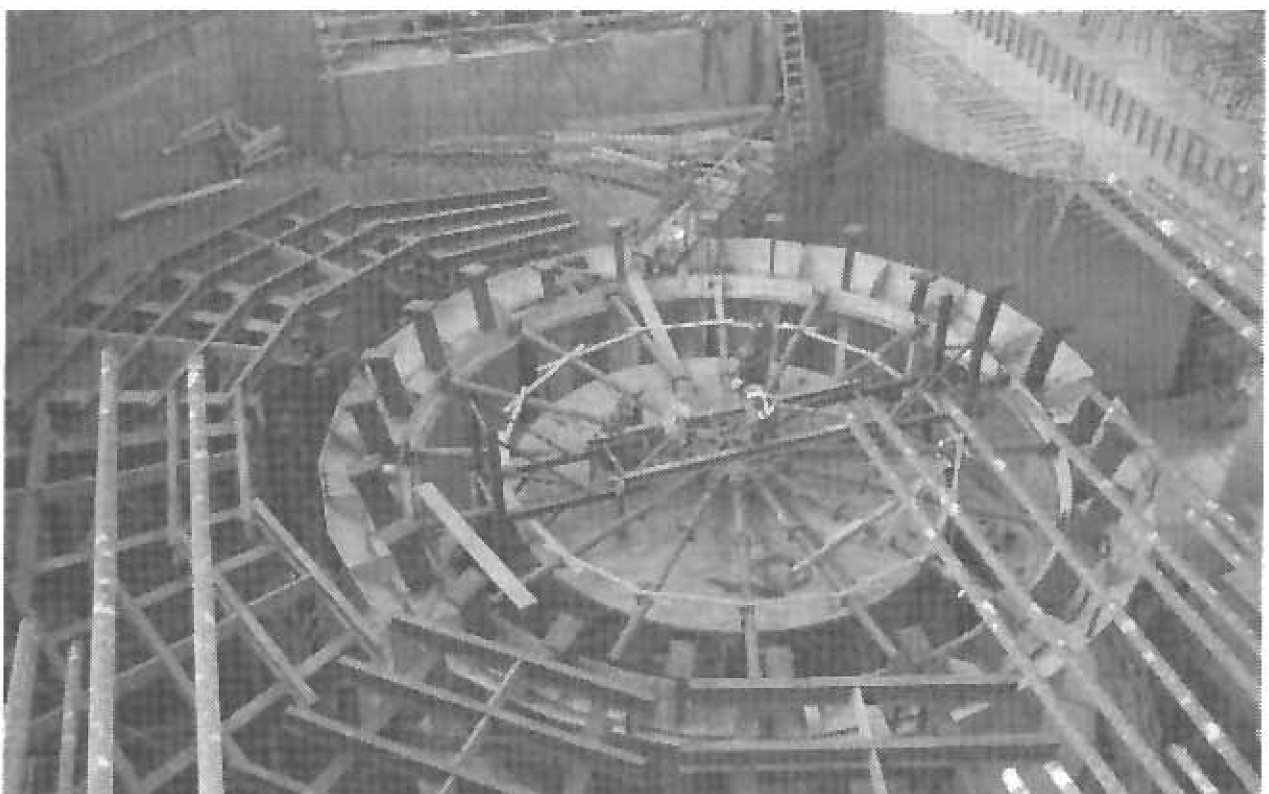
The Arrow Lakes Power Company project at Keenleyside Dam began full construction of a powerhouse on 15 March 1999. The powerhouse will contain two generating units: each is expected to be 85 MW capacity. Construction of the powerhouse may be complete as early as November 2001. The photographs shown below were taken during the week of 18 September 2000.

Downstream face of the Keenleyside powerhouse, showing the draft tube outlet.



Upstream face of the powerhouse, showing the unit intakes.

View of powerhouse construction as taken across the top of the existing structure.



Forming for a future generating turbine.

Duncan Reservoir

As shown in Chart 8, on 31 July 1999 the reservoir was within 0.2 feet of its year-end target elevation (full pool) and within 1 ksfd of its target Treaty storage (full). The Duncan reservoir reached full pool at elevation 1892.0 feet on 15 August 1999 and fluctuated up to 0.1 feet higher due to high inflows. The reservoir essentially passed inflows in August 1999 and then drafted to elevation 1884.2 feet, with a Treaty storage of 637.4 ksfd on 30 September 1999.

During the month of September, Duncan discharged an average of 5,300 cfs to maintain Kootenay Lake levels and Kootenay River flows. The project discharge averaged 6,400 cfs in October, 2,000 cfs in November and about 2,100 cfs in December. The Duncan Reservoir level was at elevation 1866.8 feet (69 percent of full) on 31 December 1999. The Duncan reservoir remained at or below the flood control curve throughout the operating year.

During January 2000, the Duncan discharge was increased to about 8,300 cfs. The reservoir was drafted throughout February and March, and reached its lowest level for the year at elevation 1794.3 feet (0.3 feet above empty) on 30 March 2000.

The Duncan discharge was reduced to minimum (100 cfs) on 9 May and remained at that level during most of June to allow refill of the reservoir. The reservoir reached elevation 1825.7 feet by 31 May and elevation 1861.4 feet by 30 June. Duncan remained on minimum discharge until 21 July and increased thereafter to slow the rate of reservoir refill. The reservoir reached full pool elevation of 1892.0 feet on 31 July 2000, and started to draft gradually in the later part of August.

Duncan passed inflows during early August 2000, but the discharge was increased later in the month to manage the Kootenay lake elevations at close to the maximum levels permitted under the IJC Order. In doing so, the Duncan reservoir drafted to elevation 1886.5 feet by month end. After 31 August 2000, the Duncan discharge was increased to raise the Kootenay Lake elevation up to the September IJC limit of 1745.42 feet, and gain increased operating efficiencies at Kootenay Canal and Corra Lynn.

Libby Reservoir

As shown in Chart 9, Lake Koocanusa began July 1999 at elevation 2433.7 feet, 25.3 feet below full. Libby Dam was completing the sturgeon pulsing operation by maintaining 30,000 cfs at

Bonners Ferry downstream. To maintain that flow, the outflow from Libby increased to as much as 25,000 cfs on 5 July when the incubation flow ended. Outflow from Libby was then gradually reduced to 8,000 cfs by 10 July. By 31 July 1999, Lake Koocanusa was at elevation 2456.94 feet, 2.1 feet from full.

Libby inflow in August 1999 was 151 percent of normal, the third highest for the period 1928-1988. Outflow ranged from 8,000 to 22,600 cfs to keep the project from filling and spilling. A peak reservoir elevation was reached on 9 August of 2458.97 feet, essentially a full pool. A 1999 Libby/Arrow storage exchange agreement was consequently not required to maintain reservoir levels. Due to the abundance of water in the Columbia Basin system, the resulting end of month elevation in August was 2455.63 feet, 3.37 feet from full and 16.63 feet above the 1995 Biological Opinion interim draft limit of elevation 2439 feet.

For the majority of September 1999, outflows were held steady at 12,000 cfs as the project began a slow draft to the 31 December 1999 flood control elevation of 2411.0 feet. Outflows were reduced to 10,000 cfs on 16 September for transmission line testing, and releases were brought back to 12,000 cfs for the remainder of the month until 26 October, when the outflow was reduced again for transmission line work.

Outflow was maintained at 12,000 cfs through 4 November, when the decision was made to reduce outflow to 8,000 cfs. At the time of the decision the November inflow was near 125 percent of average, where inflow was about 5,800 cfs, and the reservoir had evacuated to elevation 2437.65 feet. The operational strategy was to slow the evacuation and target elevation 2411 feet on 31 December 1999 to meet the recommendations of the National Marine fisheries Service 1995 Biological Opinion. The Libby basin experienced a significant storm on 13 and 14 November and inflow increased to as high as 40,000 cfs on 14 November. This storm caused the November month average inflow to be 265 percent of average, or 12,300 cfs for the month average, the largest November inflow in the 60 year period of record. The outflow from Libby had to be increased to powerhouse capacity outflow near 25,000 cfs to evacuate to elevation 2411 feet by 31 December.

Outflow near full powerhouse capacity continued through December except for a few periods of reduction for power, or to capture and tag burbot in the Kootenai River downstream of Libby. With concurrence of the National Marine fisheries Service, the elevation of Libby reservoir was 2408.1 feet on 31 December 1999. This was 2.9 feet below the flood control elevation of 2411 feet.

The January 2000 final water supply forecast was 6.87 Maf (108 percent of normal) for the April through August period. The end of January flood control evacuation requirement was elevation

2370.9 feet. Outflow near powerhouse capacity was needed for most of January to reach this elevation. The water supply forecast in February was 107 percent of normal. In order to achieve the end of February flood control evacuation, outflow averaged 16,700 cfs during February. In March, the water supply forecast sagged slightly to 6.68 Maf, or 105 percent of normal. The end of March flood control evacuation requirement was 2331.3 feet. By early March, the 95 percent confidence of refill curve at Libby on 15 April was near elevation 2339 feet. Since inflow to the project was near 4,000 cfs and minimum outflow is 4,000 cfs, the USACE decided to operate to target the 15 April, 95 percent confidence of refill curve. On 14 March the outflow was reduced to 4,000 cfs to target the 15 April refill curve. On 31 March, Lake Koocanusa was at elevation 2337.1 feet, and on 15 April the reservoir was at elevation 2342.6 feet.

Libby continued to release 4,000 cfs until 6 June 2000. When outflow was increased to meet the operation requested by the US Fish and Wildlife Service (USFWS) for sturgeon. The USFWS initially requested 19 days of release of full powerhouse from Libby. The June final water supply forecast was 6.96 Maf (109 percent of normal). At the start of the operation, Lake Koocanusa was at elevation 2403.8 feet, and was expected to refill to near elevation 2452 feet in July.

In ongoing discussions with USFWS it was agreed to release full powerhouse capacity for 17 days, followed by a slow ramp down to a flow that would not harm listed bull trout in the Kootenai River. Although 9,000 cfs was the preferred bull trout minimum flow, the USFWS agreed to 8,000 cfs in year 2000 as the June precipitation did not materialize, and the lake was not refilling as expected.

By 3 July 2000, the sturgeon operation was complete and Libby was releasing 8,000 cfs for bull trout. Lake Koocanusa was at elevation 2421.3 feet on 3 July, about 20 feet below expectations. Because of failing water supply forecast Lake Koocanusa reached its maximum elevation of 2436.33 feet on 15 August, 22.67 feet below full. Outflow of 8,000 cfs for bull trout continued through 21 September when the reservoir reached elevation 2332.9 feet. Outflow was slowly reduced to 6,000 cfs and the reservoir ended September at elevation 2432.3 feet

Kootenay Lake

As shown in Chart 10, the level of Kootenay Lake at Queens Bay was at elevation 1745.8 feet on 31 July 1999. The reservoir level reached its maximum elevation of 1746.5 feet on 10 August, but drafted to 1745 feet by month end. The lake exceeded the IJC maximum elevation of 1745.32 feet from

12 to 16 November due to high local inflows (up to 55 kcfs). Except for this event, the lake level fluctuated gradually between 1743.5 and 1745 feet, and remained below the IJC maximum between 1 September and 7 January. Releases from Duncan reservoir were completed from September to mid November, to keep the Kootenay lake elevation close to the IJC level.

For the month of September, the Kootenay Lake discharge was adjusted to keep the downstream Brilliant plant at full load while meeting the system generation demand. In September, October, November and December, the lake discharge averaged 22,900, 22,000, 30,200 and 35,300 cfs respectively. Over these four months, the month-end lake elevations varied between 1744.5 and 1744.9 feet. The Kootenay Lake had a year-end elevation of 1744.5 feet on 31 December 1999. The reservoir did not exceed the maximum IJC elevation of 1745.32 feet through to 7 January 2000.

Beginning in January, the Kootenay Lake level rose initially to 1744.8 feet and then reduced to 1743.7 feet by month end. The reservoir discharges were kept slightly above the inflows during February-March to stay below the IJC limits. The reservoir level at the end of March 2000 was 1738.6 feet. The reservoir reached a minimum level of 1738.5 feet on 3 April 2000, rising gradually thereafter with the start of the spring freshet. The inflows peaked on 15 June at 66,200 cfs. The Kootenay reservoir discharges were then also increased, and the outflows from Duncan reduced to minimum, to reduce the Kootenay reservoir level rise in the summer of 2000. Kootenay Lake discharges peaked on 26 June at 48,900 cfs.

Kootenay Lake reached its peak level for the year at elevation 1748.2 feet on 29 June 2000 about three days later than the previous year. The reservoir level gradually dropped due to receding runoff, and due to reduced Libby discharges in July 2000. Kootenay Lake drafted in these months with the lowest summer reservoir elevation of 1742.9 feet occurring on 16 August. The Kootenay Lake level at Nelson dropped below the Nelson gauge IJC elevation of 1743.32 feet on 14 August and the lake operation remained constrained until 31 August as required by the IJC Order for Kootenay Lake. During the balance of August, outflows from Libby remained low and Duncan discharges were adjusted to manage Kootenay operations until the end of August. Discharges from Kootenay Lake averaged 35,500 cfs in July and 23,800 cfs in August 2000. The lake discharges in September were adjusted to keep Brilliant at full load without spill, while restoring operational head at Corra Linn and Kootenay Canal.

VI Power and Flood Control Accomplishments

General

During the period covered by this report, Duncan, Arrow, and Mica reservoirs were operated for power, flood control, and other benefits in accordance with the Columbia River Treaty and operating plans and agreements described in Section III. Consistent with all DOP's prepared since the installation of generation at Mica, the 1999-00 and 2000-01 DOP's were 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.

During the period covered by this report, Libby reservoir was operated for flood control and other purposes in accordance with the Treaty and the 1972 and revised 1999 "Columbia River Treaty Flood Control Operating Plan". During a portion of the year, Libby operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). During the remainder of the operating year, Libby operated for storage and releases recommended for endangered white sturgeon and salmon by the USFWS and the U.S. National Marine Fishery Service Biological Opinions.

Flood Control

The Columbia River Basin reservoir system, including the Columbia River Treaty projects, was not operated for flood control during the 1999-2000 winter period, since the weekly agreed-to operations were adequate to accomplish spring flood evacuation control goals. The weekly operation was guided to a large extent by the daily streamflow and reservoir simulations and to a lesser degree by the charts in the Flood Control Operating Plan. Early on there was only a low potential for flooding. Weather conditions in May and June moderated runoff to the point that the reservoir system was easily able to control river flows to desirable levels. The unregulated flow at The Dalles, Oregon, shown on chart 14, is estimated at 449,600 cfs on 27 May and a regulated flow of 375,100 cfs on 23 April. The unregulated stage at Vancouver, Washington was 16.5 feet on 27 May and the high-observed stage was 11.5 feet on 24 April.

Chart 15 shows the relative filling of Arrow and Grand Coulee during the filling period and compares the regulation to guide lines, Chart 6, of the Columbia River Treaty Flood Control Operating Plan. Because this years runoff volume was forecast to be near normal, 99 percent, and Mica was drafted very deeply for power, there was no daily operations specified for Arrow, and the projects were able to meet both fish flow and flood control objectives.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. Computed Initial Controlled Flows at The Dalles were 332,000 cfs on 1 January 1999, 342,000 cfs on 1 February, 338,000 cfs on 1 March, 335,000 cfs on 1 April, and 309,000 cfs on 1 May. As mentioned earlier, the observed peak flow at The Dalles was 375,100 cfs on 23 April. Data for the 1 May ICF computation are given in Table 6.

Canadian Entitlement

From 1 August 1999 through 31 July 2000, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Duncan and Arrow reservoirs to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amount returned, not including transmission losses and scheduling adjustments, was 306.8 average MW at rates up to 801.7 MW. No Entitlement power was disposed directly in the U.S. during 1 August 1999 through 31 July 2000, as was allowed by the 29 March 1999 Agreements on "Aspects of the Delivery of the Canadian Entitlement for 4/1/98 Through 9/15/2024" and "Disposals of the Canadian Entitlement Within the U.S. for 4/1/98 Through 9/15/2024."

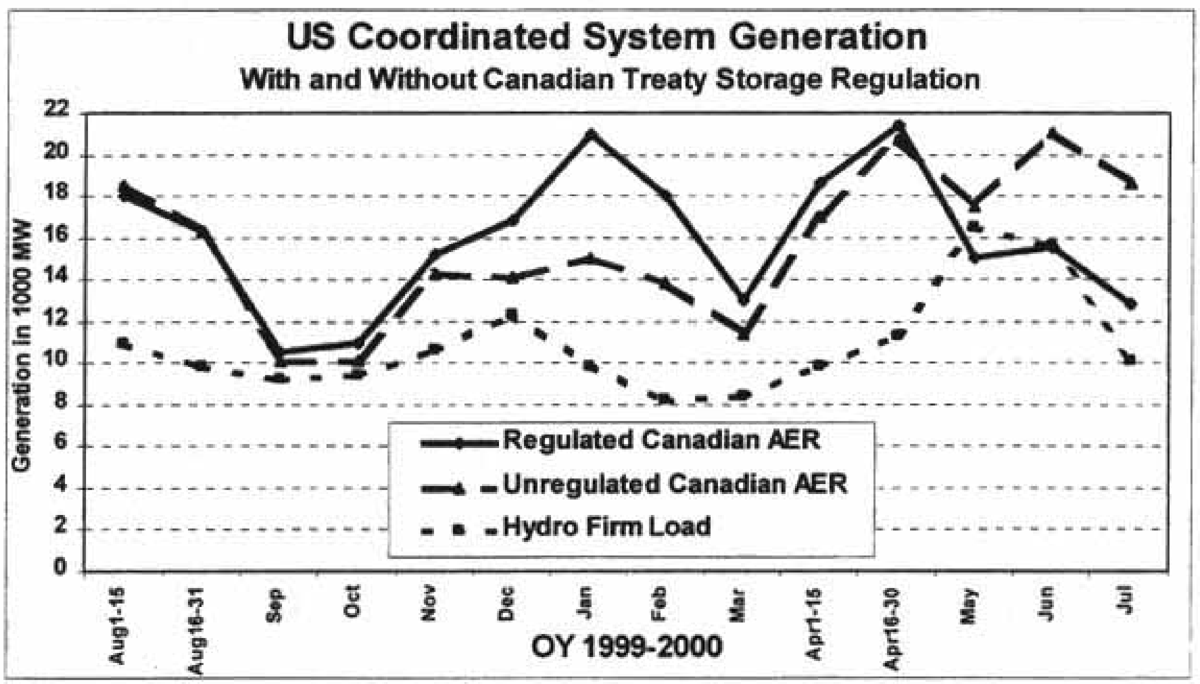
In accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement (CEPA), B.C. Hydro delivered to BPA 0.4 average megawatts of energy and no dependable capacity during the period 1 April 1999 through 31 March 2000, and no energy and no dependable capacity during the period 1 April 2000 through 31 March 2001

In accordance with the Canadian Entitlement Exchange Agreement dated 13 August 1964, the U.S. Entity delivered capacity and energy to the Columbia Storage Power Exchange (CSPE) participants. Delivery under the Canadian Entitlement Exchange was 103 average megawatts at rates up to 200 MW from 1 August 1999 through 31 March 2000, and 99 average megawatts at rates up to 192 MW from 1 April 2000 through 31 July 2000.

Power Generation and Other Accomplishments

The Coordinated System storage level at the beginning of the 1999-2000 operating year was 99.87 percent full as of 1 August 1999 as measured in the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). The Treaty Storage operation in the AER is fixed from the TSR study. Since the system was 99.87 percent full, 1st-year firm energy load carrying capability (FELCC) was adopted for the U.S. system from the PNCA critical period studies. Due to above average streamflows throughout the year, the system generally operated to Operating Rule Curve (ORC) or flood control for the entire period, producing large amounts of surplus energy. The coordinated system storage level reached 97.07 percent full on 31 July 2000, as measured in the AER, and the system adopted 1st-year FELCC from the 2000-01 PNCA Final Regulation study.

Actual U.S. power benefits from the operation of Treaty storage are unknown due to the operating procedures, nonpower requirements, and market conditions in the absence of Treaty storage. However, the following graph shows a rough estimate of the average monthly impact on downstream U.S.

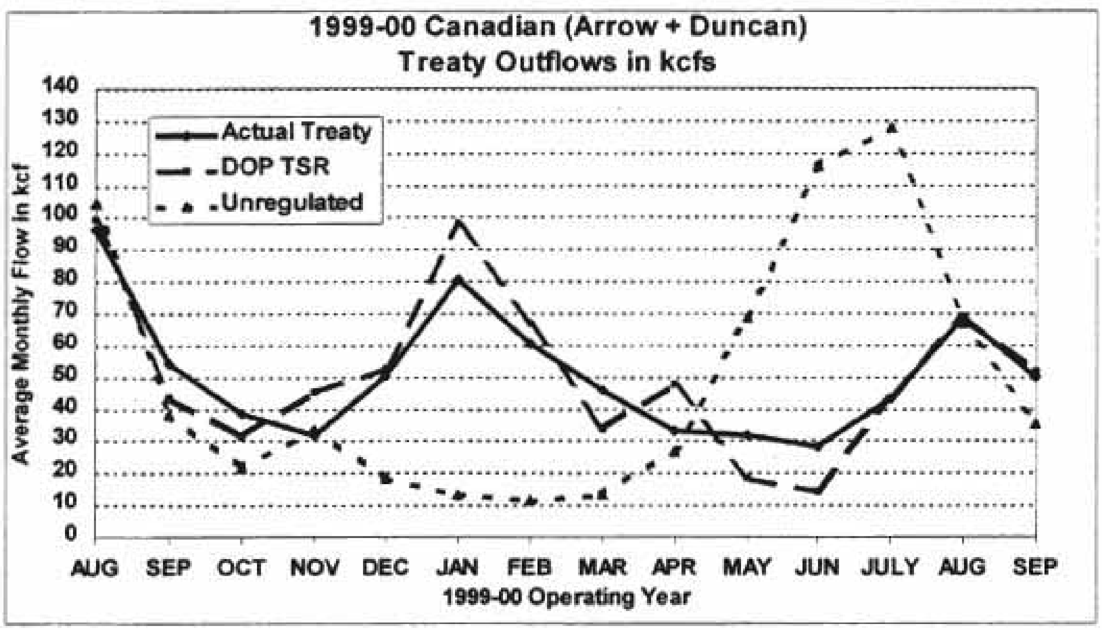


power generation during the 1999-00 operating year, with and without the regulation of Canadian Treaty storage, based on the PNCA AER that includes minimum flow and spill constraints for U.S. fishery objectives.

Based on the authority from the 1999-00 and 2000-01 DOP's, the Operating Committee completed several operating agreements, described in Section III, that resulted in power and other benefits both in Canada and the U.S. Other benefits include increased reservoir levels for summer recreation and dust storm avoidance and changes to streamflows below Arrow that enhanced trout and white fish spawning and the downstream migration of salmon. The graph below shows the difference in Arrow plus Duncan average monthly regulated outflows between the DOP TSR and the actual Treaty flows due to these agreements. The unregulated stream flows are also shown for comparison purposes.

As of 30 September 1999, the sum of Canadian Treaty storage was positioned 315 ksfd below the DOP TSR. The U.S. Entity had exercised provisional draft rights during September per the terms of the Whitefish Agreement.

In October 1999, the U.S. exhausted its provisional draft accounts by drafting an additional 85 ksfd from Arrow to increase the Grand Coulee forebay level, such that the sum of Canadian Treaty storage was positioned 400 ksfd below the DOP TSR. Beginning mid November, the U.S. returned the provisional draft due to increasing streamflows resulting from significant rain and snowmelt. On 31 December 1999 Canadian Treaty storage was positioned at the DOP TSR level.



Beginning January 2000, Arrow's discharge was reduced below TSR levels per the terms of the Whitefish Agreement. Storage above the TSR during January and February was accomplished for

U.S. Flow Augmentation (377 ksfd) and Canadian Whitefish (344 ksfd). During the month of March, the Whitefish storage was released to maintain incubation flows over Whitefish eggs.

During the April through July 2000 period, water was stored and released in a manner consistent with Canada's need for trout spawning and progressive Arrow refill consistent with U.S. flood control requirements. At the end of April, storage above the TSR was 745 ksfd. By July 2000, Canadian storage was returned to its TSR elevation

Table 1
Unregulated Runoff Volume Forecasts
Million of Acre-Feet
2000

Forecast Date - 1st of	Duncan Most Probable 1 April - 31-Aug	Arrow Most Probable 1 April - 31-Aug	Mica Most Probable 1 April - 31-Aug	Libby Most Probable 1 April - 31-Aug	Columbia River at The Dalles, Oregon Most Probable 1 April - 31-Aug
January	2.24	25.3	12.5	6.87	94.2
February	2.11	24.7	12.1	6.8	93.6
March	2.11	23.5	11.5	6.68	92.6
April	2.14	24.2	11.9	6.87	92.5
May	2.11	24	12	7.02	92.5
June	2.1	24	11.9	6.87	93
Actual	2.06	22.5	10.7	5.5	84.3

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

TABLE 2
2000 Variable Refill Curve

Mica Reservoir		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			10340.0	10050.4	9328.4	9326.4	8965.4	7630.5
PROBABLE DATE-31JULY INFLOW,KSFD	**		5213.0	5067.0	4703.0	4702.0	4520.0	3847.0
95% FORECAST ERROR FOR DATE, KSFD			653.0	510.4	465.4	444.5	360.5	360.5
95% CONF.DATE-31JULY INFLOW,KSFD	1/		4560.0	4556.6	4237.6	4257.5	4159.5	3486.5
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		4560.0					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		19300.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		4625.7					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		3529.2					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		2470.1					
JAN31 ECC,FT.	7/		2461.9					
BASE ECC, FT		2470.1						
LOWER LIMIT,FT		2406.3						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		4450.5	4447.2				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		19300.0	19300.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		4084.4	4033.1				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		3163.1	3115.1				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		2456.0	2456.0				
FEB28 ECC,FT.	7/		2456.0	2456.0				
BASE ECC,FT		2470.1						
LOWER LIMIT,FT		2401.9						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		4336.5	4333.3	4127.4			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		23300.0	23100.0	23300.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		3485.1	3442.1	3485.1			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		2677.8	2638.0	2886.8			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		2449.6	2449.6	2449.6			
MAR31 ECC,FT.	7/		2449.6	2449.6	2449.6			
BASE ECC,FT		2470.1						
LOWER LIMIT,FT		2397.0						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		4104.0	4100.9	3907.1	4031.8		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		23300.0	23100.0	23300.0	23300.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		2785.1	2750.1	2785.1	2785.1		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		2210.3	2178.4	2407.2	2282.5		
MIN APR30 RESERVOIR CONTENT,FEET	6/		2444.0	2443.4	2448.1	2445.5		
APR30 ECC,FT.	7/		2444.0	2443.4	2448.1	2445.5		
BASE ECC,FT		2455.0						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		3264.9	3262.5	3106.2	3205.9	3306.8	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		25300.0	25300.0	25300.0	25300.0	25300.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		1999.7	1966.8	1999.7	1999.7	1999.7	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		2264.0	2233.5	2422.8	2323.1	2222.1	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		2445.1	2444.5	2448.4	2446.4	2444.3	
MAY31 ECC,FT.	7/		2445.1	2444.5	2448.4	2446.4	2444.3	
BASE ECC,FT		2450.7						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		1618.8	1617.6	1538.3	1588.0	1638.9	1725.8
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		27700.0	27100.0	27700.0	27700.0	27700.0	27700.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		1169.7	1152.8	1169.7	1169.7	1169.7	1203.6
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		3080.1	3064.4	3160.7	3110.9	3160.1	3007.0
MIN JUN30 RESERVOIR CONTENT,FEET	6/		2461.5	2461.1	2463.0	2462.1	2461.1	2460.0
JUN30 ECC,FT.	7/		2461.5	2461.1	2462.7	2462.1	2461.1	2460.0
BASE ECC,FT		2462.6						
JUL 31 ECC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (3529.2 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 3

2000 Variable Refill Curve

Arrow Reservoir		INITIAL	JAN 1 Local	FEB 1 Local	MAR 1 Local	APR 1 Local	MAY 1 Local	JUN 1 Local
PROBABLE DATE-31JULY INFLOW,KAF			11829.6	11595.5	10697.0	10643.5	9425.6	6958.1
& IN KSFD	**		5964.0	5846.0	5393.0	5366.0	4752.0	3508
95% FORECAST ERROR FOR DATE,IN KSFD			762.0	632.8	505.1	403.5	341.6	341.6
95% CONF.DATE-31JULY INFLOW,KSFD	1/		5202.0	5213.2	4887.9	4962.5	4410.4	3166.4
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		5202.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	3/		2904.7					
UPSTREAM DISCHARGE,KSFD	4/		3635.8					
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		0.0					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		1377.9					
JAN31 ECC,FT.	7/		1385.3					
BASE ECC, FT		1429.8						
LOWER LIMIT, FT		1385.3						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.3	97.3				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		5061.6	5072.4				
MIN MAR1-JUL31 OUTFLOW,KSFD	3/		2708.7	2701.5				
UPSTREAM DISCHARGE,KSFD	4/		2997.8	2865.8				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		0.0	0.0				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		1377.9	1377.9				
FEB28 ECC,FT.	7/		1384.6	1384.6				
BASE ECC, FT		1415.9						
LOWER LIMIT, FT		1384.6						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			93.9	93.9	96.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		4884.7	4895.2	4712.0			
MIN APR1-JUL31 OUTFLOW,KSFD	3/		2398.7	2391.5	2398.7			
UPSTREAM DISCHARGE,KSFD	4/		2346.8	2214.8	1990.3			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		0.0	0.0	0.0			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		1377.9	1377.9	1377.9			
MAR31 ECC,FT.	7/		1381.5	1381.5	1381.5			
BASE ECC,FT		1401.3						
LOWER LIMIT, FT		1381.5						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			85.3	85.3	87.6	90.9		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		4437.3	4446.8	4281.8	4510.9		
MIN MAY1-JUL31 OUTFLOW,KSFD	3/		2063.7	2057.5	2063.7	2063.7		
UPSTREAM DISCHARGE,KSFD	4/		1461.8	1329.8	1105.3	1226.6		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		0.0	0.0	256.1	0.0		
MIN APR30 RESERVOIR CONTENT,FEET	6/		1377.9	1377.9	1384.0	1377.9		
APR30 ECC,FT.	7/		1377.9	1377.9	1384.0	1377.9		
BASE ECC, FT		1399.8						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			59.9	59.9	61.5	63.8	70.2	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		3116.0	3122.7	3006.1	3166.1	3096.1	
MIN JUN1-JUL31 OUTFLOW,KSFD	3/		1681.3	1677.3	1681.3	1681.3	1681.3	
UPSTREAM DISCHARGE,KSFD	4/		1151.8	1019.8	795.3	916.6	985.4	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		993.2	1114.4	1459.6	1178.3	1179.4	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		1399.6	1402.0	1408.5	1403.2	1403.2	
MAY31 ECC,FT.	7/		1399.6	1402.0	1408.5	1403.2	1403.2	
BASE ECC,FT		1417.1						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			25.6	25.6	26.3	27.3	30.0	42.7
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		1331.7	1334.6	1285.5	1354.8	1323.1	1352.0
MIN JUL1-JUL31 OUTFLOW,KSFD	3/		1281.3	1279.3	1281.3	1281.3	1281.3	1285.5
UPSTREAM DISCHARGE,KSFD	4/		851.8	719.8	495.3	616.6	685.4	674.6
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2677.4	2804.5	3080.1	2889.5	2852.4	2838.4
MIN JUN30 RESERVOIR CONTENT,FEET	6/		1429.8	1431.8	1436.2	1433.2	1432.6	1432.4
JUN30 ECC,FT.	7/		1429.8	1431.8	1436.2	1433.2	1432.6	1432.4
BASE ECC,FT		1436.9						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT. 5/ FULL CONTENT (3579.6 KSFD) MINUS 2/ PLUS 3/ MINUS /4.
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR ELEV DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 4

2000 Variable Refill Curve

Duncan Reservoir		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			1929.9	1822.8	1781.2	1763.3	1600.7	1255.6
& IN KSFD	**		973.0	919.0	898.0	889.0	807.0	633.0
95% FORECAST ERROR FOR DATE,IN KSFD			118.4	108.9	97.5	88.1	73.3	73.3
95% CONF.DATE-31JULY INFLOW,KSFD	1/		854.6	810.1	800.5	800.9	733.7	559.7
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		854.6					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		300.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		106.3					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		0.0					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		1794.5					
JAN31 ECC,FT	7/		1794.5					
BASE ECC,FT		1839.0						
LOWER LIMIT, FT		1794.5						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		835.8	792.2				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		300.0	300.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		97.9	97.9				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		0.0	11.5				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		1794.3	1797.1				
FEB28 ECC,FT.	7/		1794.3	1797.1				
BASE ECC,FT		1838.6						
LOWER LIMIT, FT		1794.3						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		814.5	772.0	779.7			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		500.0	500.0	500.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		88.6	88.6	88.6			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		0.0	22.4	14.7			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		1795.1	1799.5	1797.8			
MAR31 ECC,FT.	7/		1795.1	1799.5	1797.8			
BASE ECC,FT		1834.5						
LOWER LIMIT, FT		1795.1						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		762.3	722.6	729.2	748.8		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		500.0	500.0	500.0	500.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		73.6	73.6	73.6	73.6		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		17.1	56.8	50.2	30.6		
MIN APR30 RESERVOIR CONTENT,FEET	6/		1798.3	1806.2	1805.0	1801.2		
APR30 ECC,FT.	7/		1798.3	1806.2	1805.0	1801.2		
BASE ECC,FT		1833.5						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		577.7	547.6	553.1	567.8	556.1	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		800.0	800.0	800.0	800.0	800.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		48.8	48.8	48.8	48.8	48.8	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		176.9	207.0	201.5	186.8	198.5	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		1825.6	1830.0	1829.2	1827.1	1828.8	
MAY31 ECC,FT.	7/		1825.6	1830.0	1829.2	1827.1	1828.8	
BASE ECC,FT		1846.6						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		270.9	256.8	259.4	266.7	261.2	262.5
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		800.0	800.0	800.0	800.0	800.0	800.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		24.8	24.8	24.8	24.8	24.8	24.8
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		459.7	473.8	471.2	463.9	469.4	468.1
MIN JUN30 RESERVOIR CONTENT,FEET	6/		1863.2	1865.0	1864.6	1863.7	1864.4	1864.3
JUN30 ECC,FT.	7/		1863.2	1865.0	1864.6	1863.7	1864.4	1864.3
BASE ECC,FT		1870.2						
JUL 31 ECC, FT..................			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (705.8 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 5
1999 Variable Refill Curve
Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			6743.0	6920.0	6872.0	7065.0	7154.0	7152.0
PROBABLE DATE-31JULY INFLOW,KSFD			3399.6	3488.8	3464.6	3561.9	3606.8	3605.8
95% FORECAST ERROR FOR DATE, KSFD			886.8	606.4	552.5	533.4	474.5	367.5
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	166.9	293.9	418.0	748.7	1458.6
95% CONF.DATE-31JULY INFLOW,KSFD	1/		2512.8	2715.5	2618.2	2610.6	2383.6	1779.8
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		2436.4					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		4400.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		934.2					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		1008.3					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		2380.1					
JAN31 ECC,FT.	7/		2380.1					
BASE ECC, FT		2422.8						
LOWER LIMIT,FT		2366.0						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		2366.6	2637.9				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		5000.0	5000.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		811.0	811.0				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		954.9	683.6				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		2376.3	2355.6				
FEB28 ECC,FT.	7/		2376.3	2355.6				
BASE ECC,FT		2420.2						
LOWER LIMIT,FT		2331.4						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		2281.9	2543.4	2524.5			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		5000.0	5000.0	5000.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		656.0	656.0	656.0			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		884.6	623.1	642.0			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		2371.2	2350.6	2352.2			
MAR31 ECC,FT.	7/		2371.2	2350.6	2352.2			
BASE ECC,FT		2417.5						
LOWER LIMIT,FT		2303.0						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			82.7	85.3	87.8	91.1		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		2078.1	2316.1	2298.8	2377.5		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		5500.0	5500.0	5500.0	5500.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		506.0	506.0	506.0	506.0		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		938.4	700.4	717.7	639.0		
MIN APR30 RESERVOIR CONTENT,FEET	6/		2375.1	2356.9	2358.4	2351.9		
APR30 ECC,FT.	7/		2375.1	2356.9	2358.4	2351.9		
BASE ECC,FT		2416.6						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			55.3	57.0	58.7	60.9	66.9	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		1389.1	1548.4	1536.9	1589.3	1593.4	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		5500.0	5500.0	5500.0	5500.0	5500.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		335.5	335.5	335.5	335.5	335.5	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		1456.9	1297.6	1309.1	1256.7	1252.6	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		2408.5	2399.2	2399.9	2396.6	2396.4	
MAY31 ECC,FT.	7/		2408.5	2399.2	2399.9	2396.6	2396.4	
BASE ECC,FT		2436.1						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			19.6	20.2	20.8	21.6	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		492.5	549.1	544.8	563.4	564.9	630.9
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		5500.0	5500.0	5500.0	5500.0	5500.0	5500.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		170.5	170.5	170.5	170.5	170.5	170.5
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2188.5	2131.9	2136.2	2117.6	2116.1	2050.1
MIN JUN30 RESERVOIR CONTENT,FEET	6/		2444.8	2442.2	2442.4	2441.6	2441.5	2438.5
JUN30 ECC,FT.	7/		2444.8	2442.2	2442.4	2441.6	2441.5	2438.5
BASE ECC,FT		2459.0						
JUL 31 ECC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLY BIRD, Maf	8/		104.0	110.0	106.0	105.0	105.0	103.0

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW. 2/PRECEEDING LINE TIMES 1/.5/ FULL CONTENT (2510.5 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143. 7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN 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-2000

1 May Forecast of May-August Unregulated Runoff Volume, Maf		75.1
Less Estimated Depletions, Maf		1.5
Less Upstream Storage Corrections, Maf		25.594
MICA	7.140	
ARROW	5.000	
DUNCAN	1.359	
LIBBY	3.652	
LIBBY + DUNCAN UNDER DRAFT	0.00	
HUNGRY HORSE	1.106	
FLATHEAD LAKE	0.500	
NOXON RAPIDS	0.000	
PEND OREILLE LAKE	0.500	
GRAND COULEE	3.306	
BROWNLEE	0.274	
DWORSHAK	1.107	
JOHN DAY	0.180	
TOTAL	25.594	25.594
Forecast of Adjusted Residual Runoff Volume, Maf		49.506
Computed Initial Controlled Flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		309

Chart 1

Seasonal Precipitation
Columbia River Basin
October 1999 – September 2000
Percent of 1961 – 1990 Average

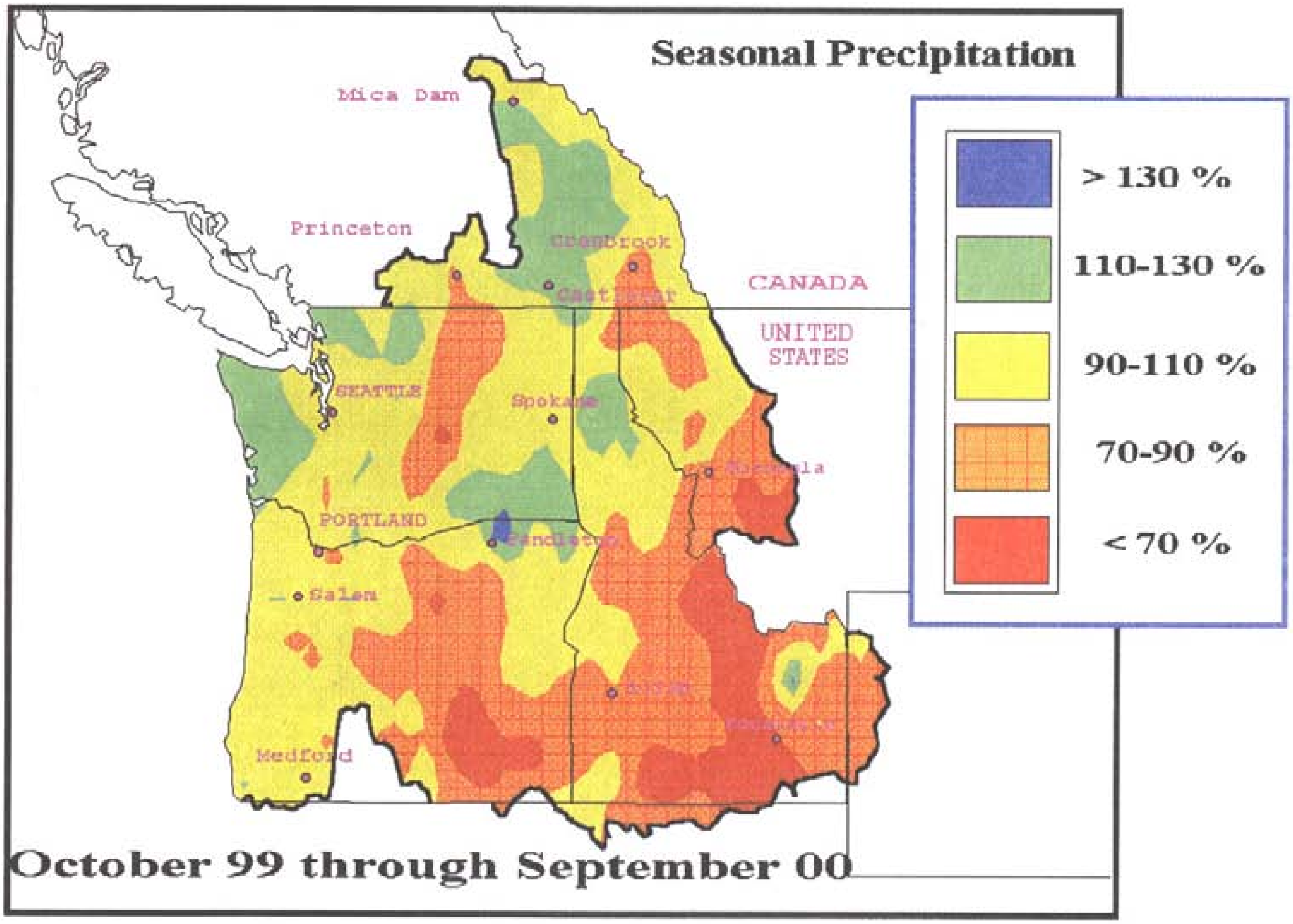
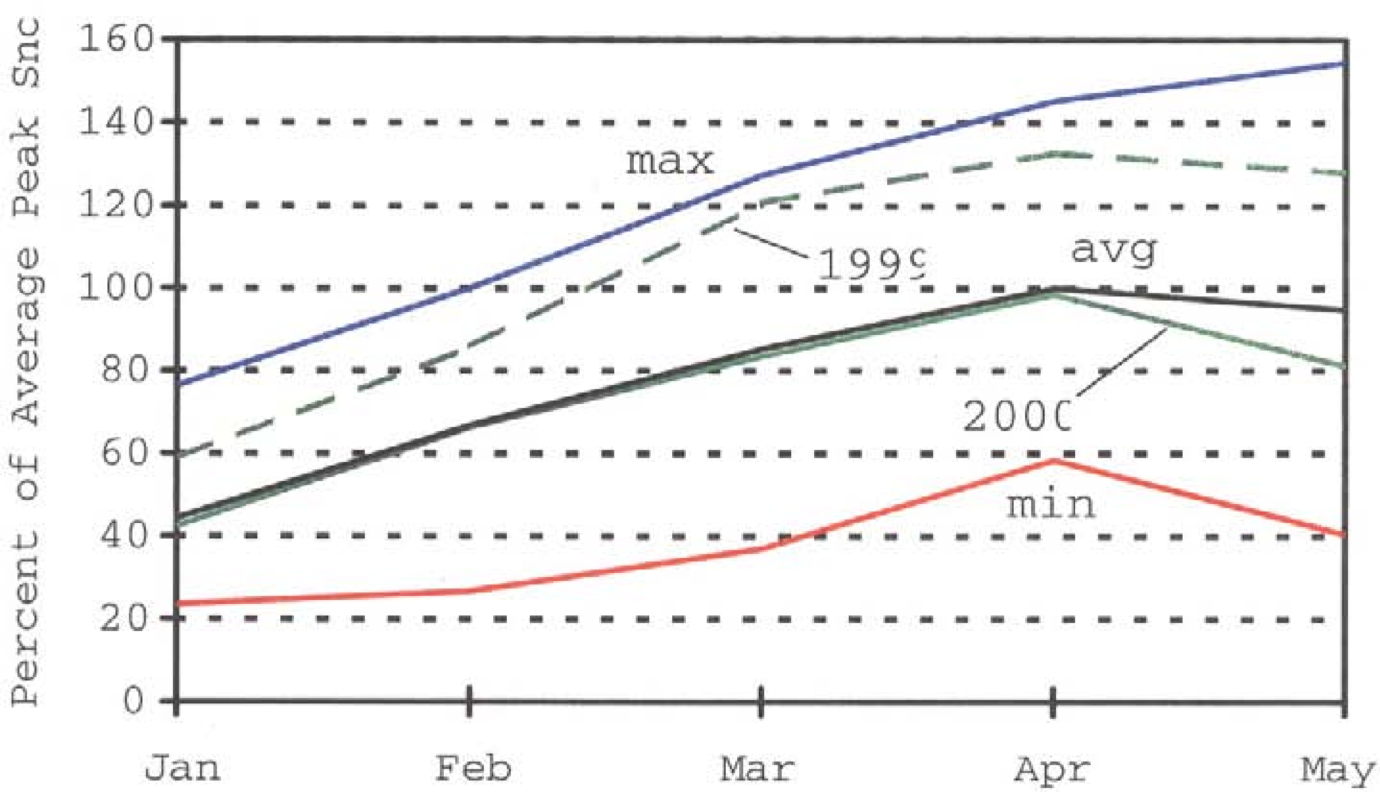
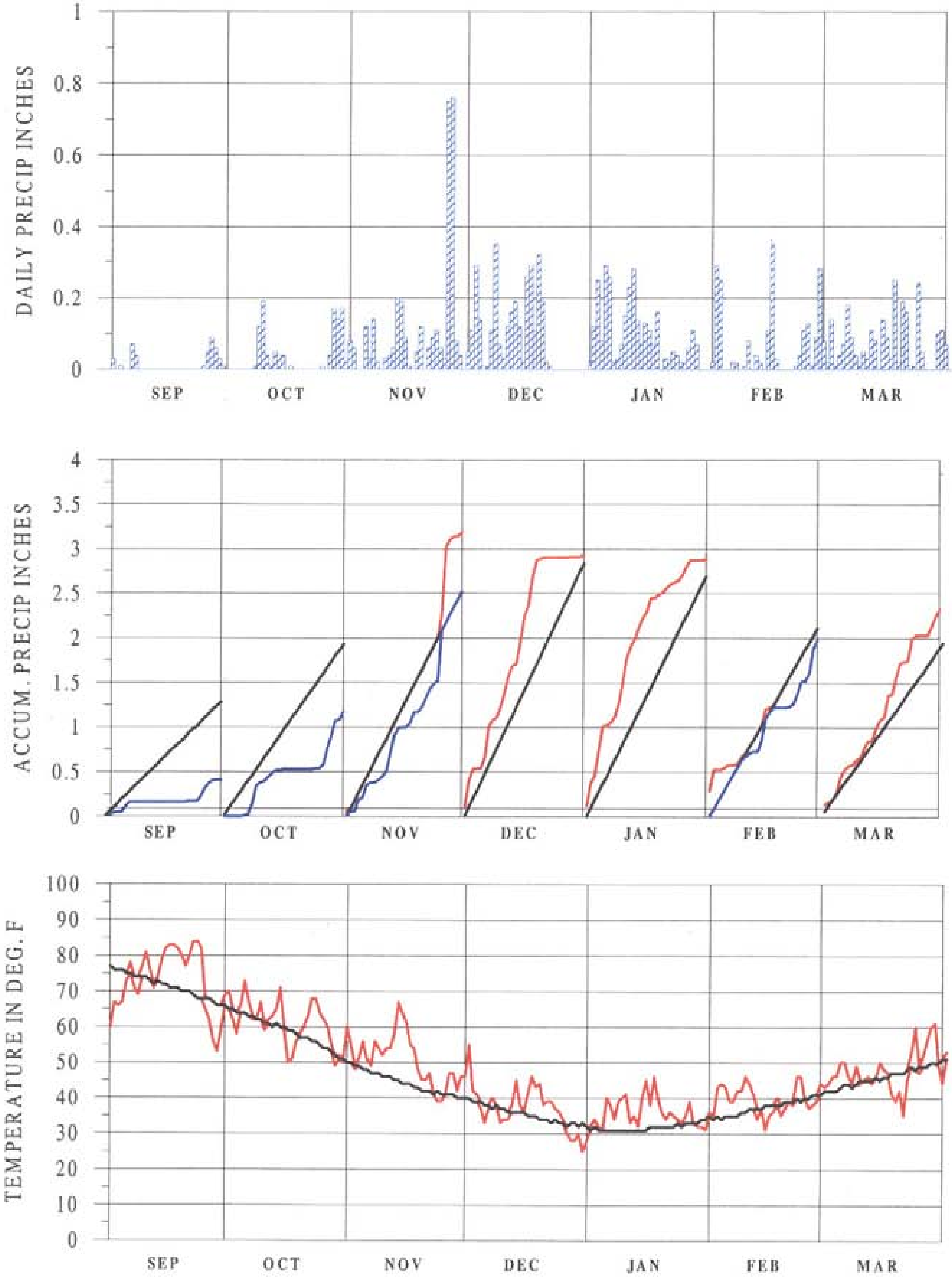


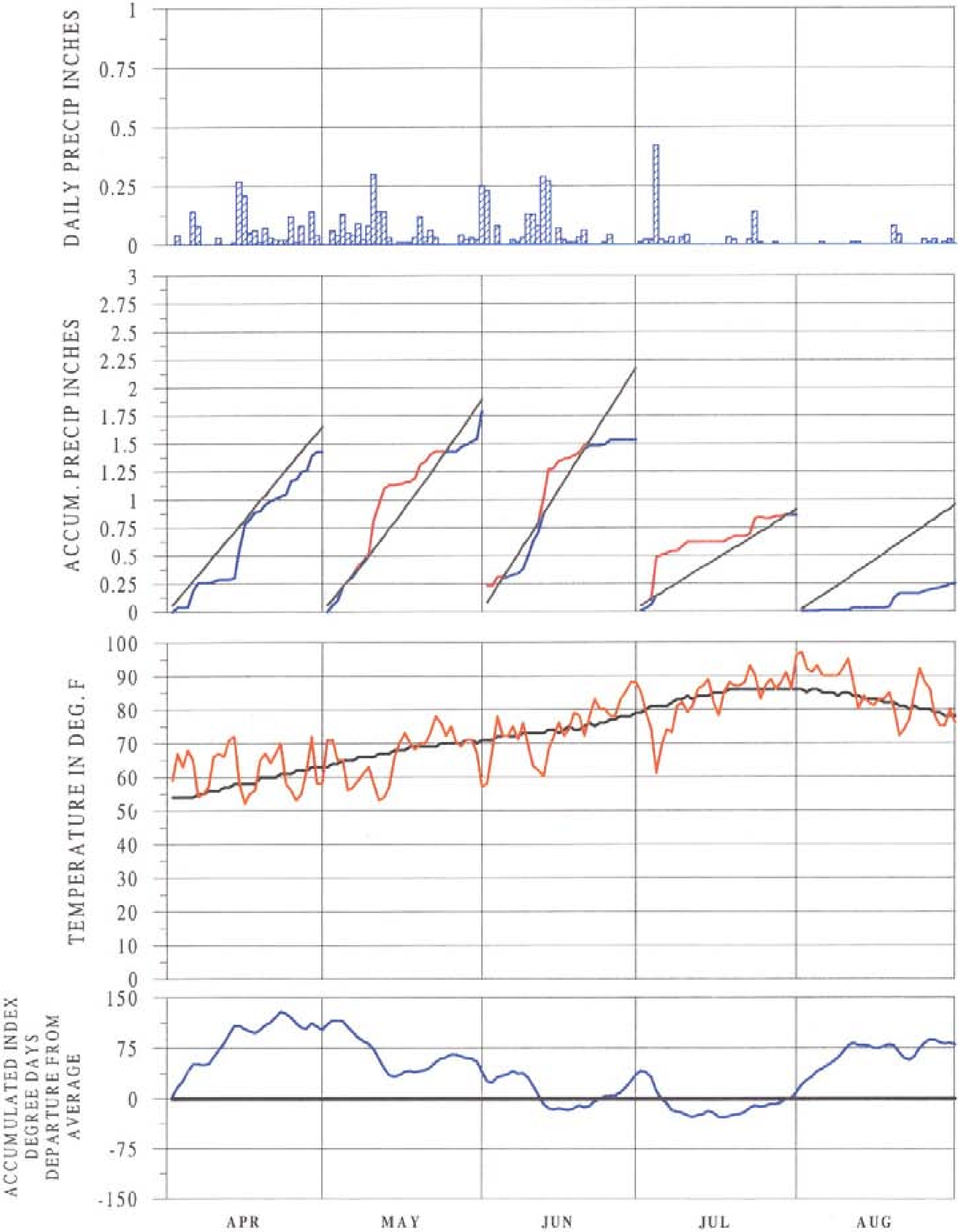
Chart 2
Columbia Basin Snowpack





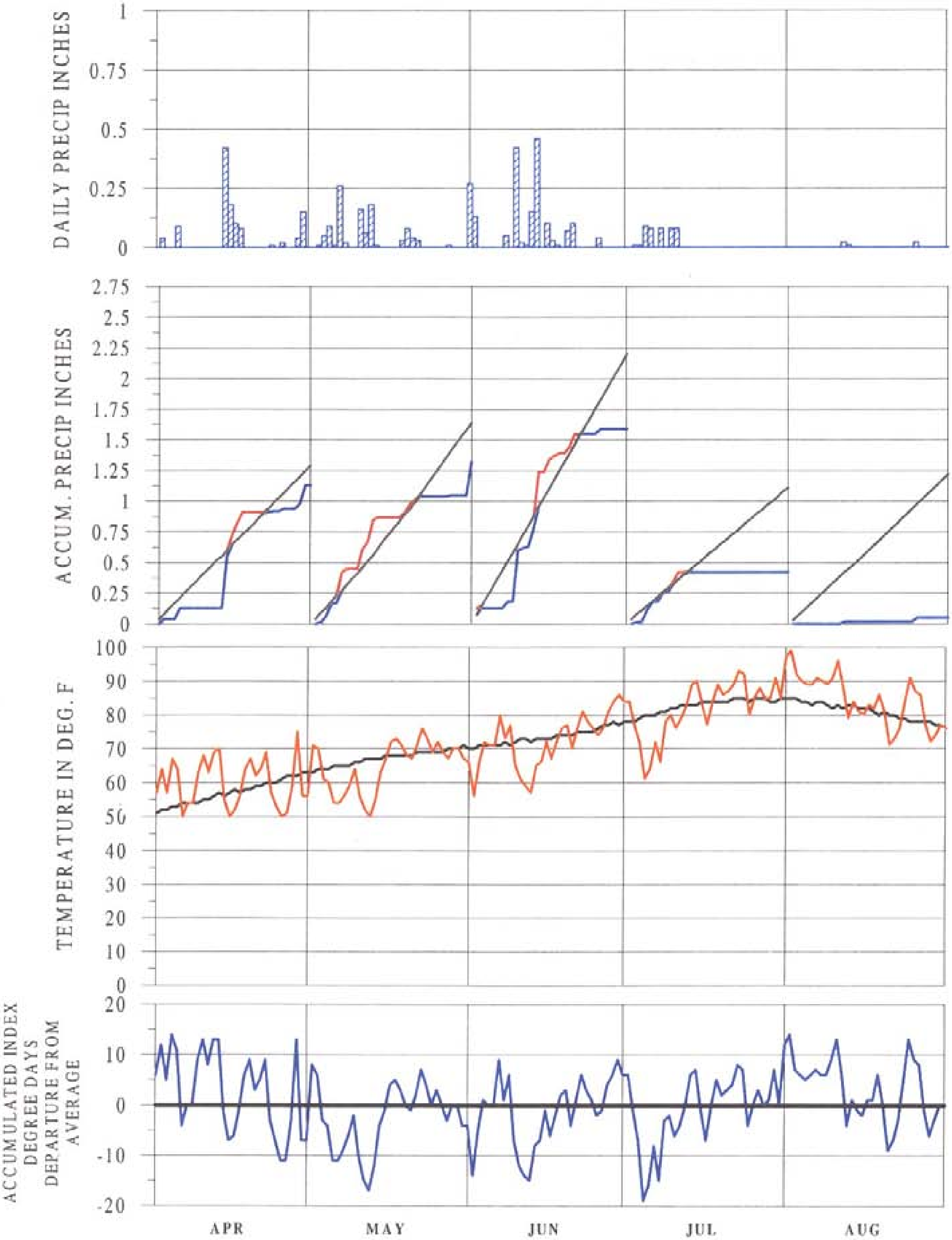
WINTER SEASON
TEMPERATURE AND PRECIPITATION INDEX 1999-2000
COLUMBIA RIVER BASIN ABOVE THE DALLES, OREGON

CHART 3



SNOWMELT SEASON
TEMPERATURE AND PRECIPITATION INDEX 2000
COLUMBIA RIVER ABOVE THE DALLES, OR

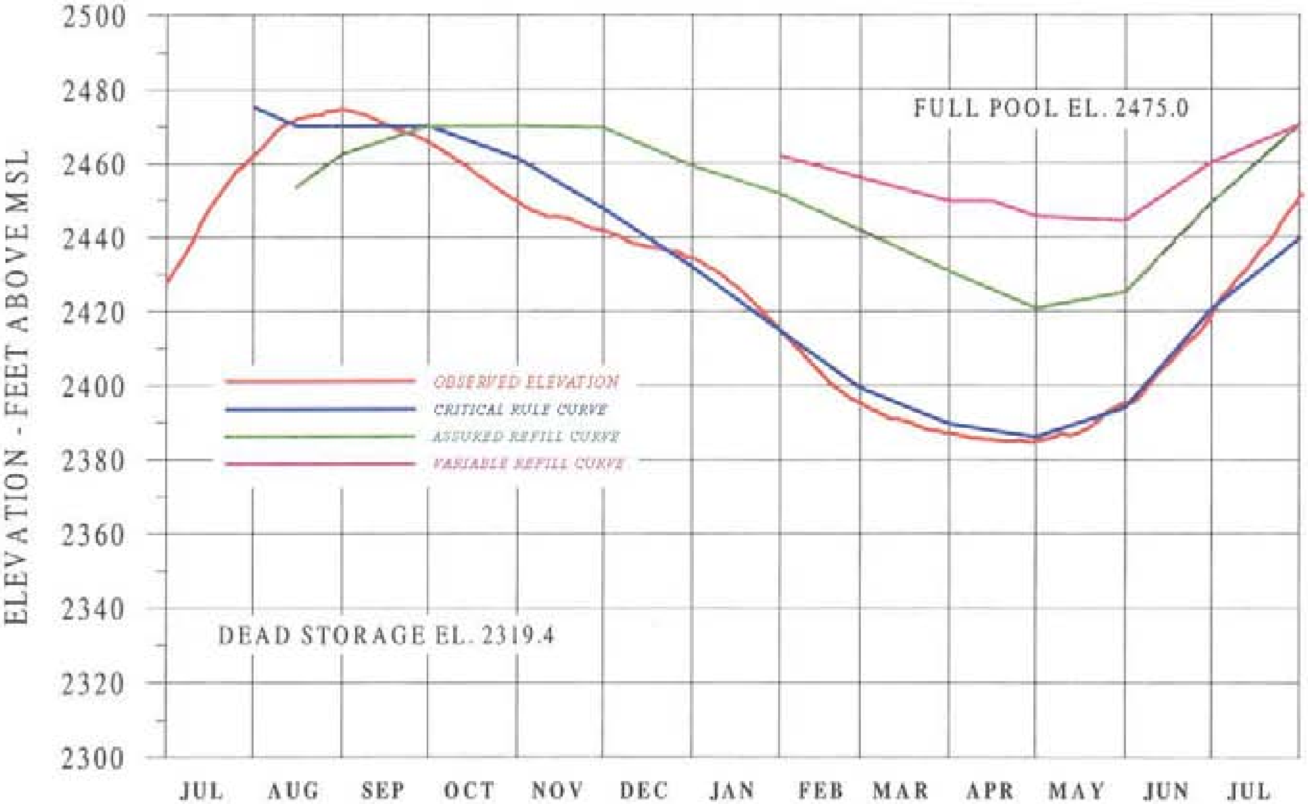
CHART 4



SNOWMELT SEASON
TEMPERATURE AND PRECIPITATION INDEX 2000
COLUMBIA RIVER BASIN ABOVE COULEE

CHART 5

CHART 6
REGULATION OF MICA
1 JULY 1999 - 31 JULY 2000



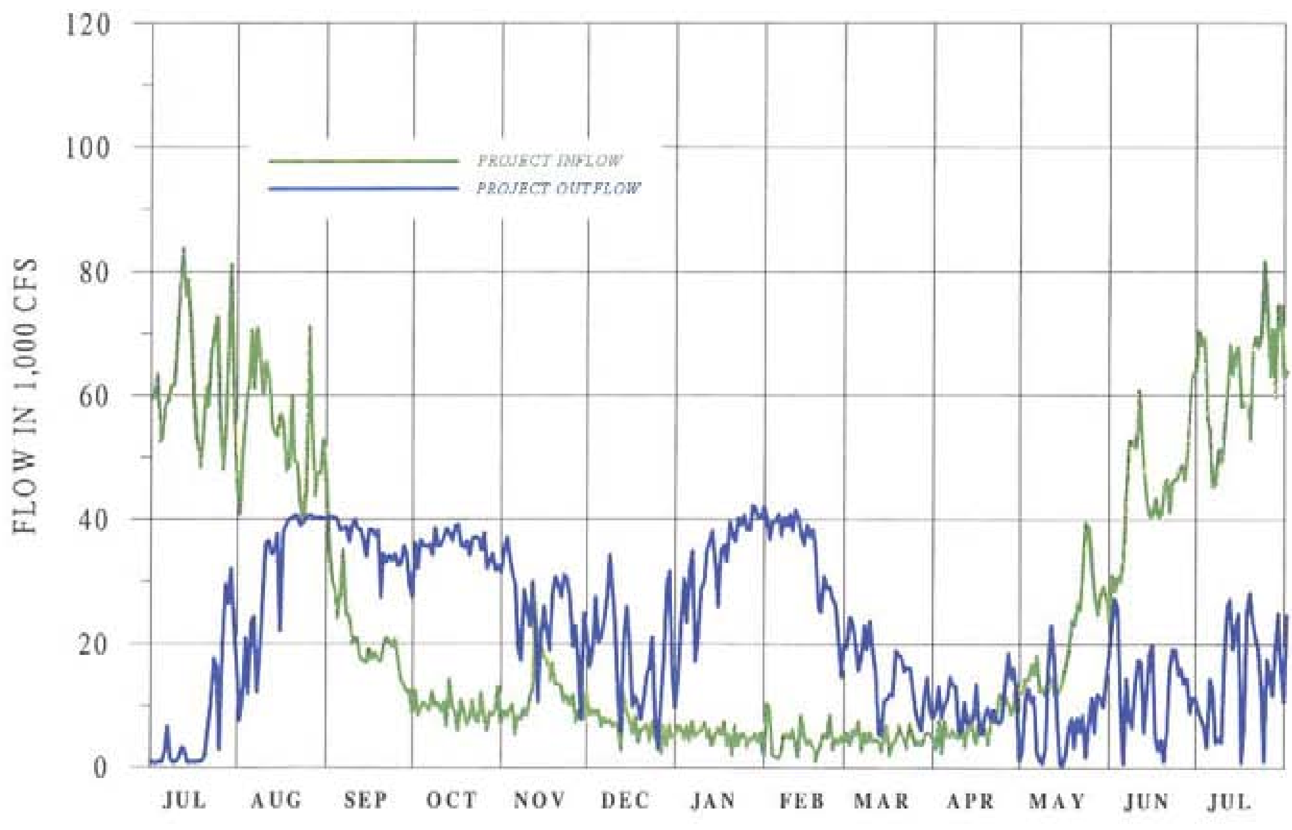
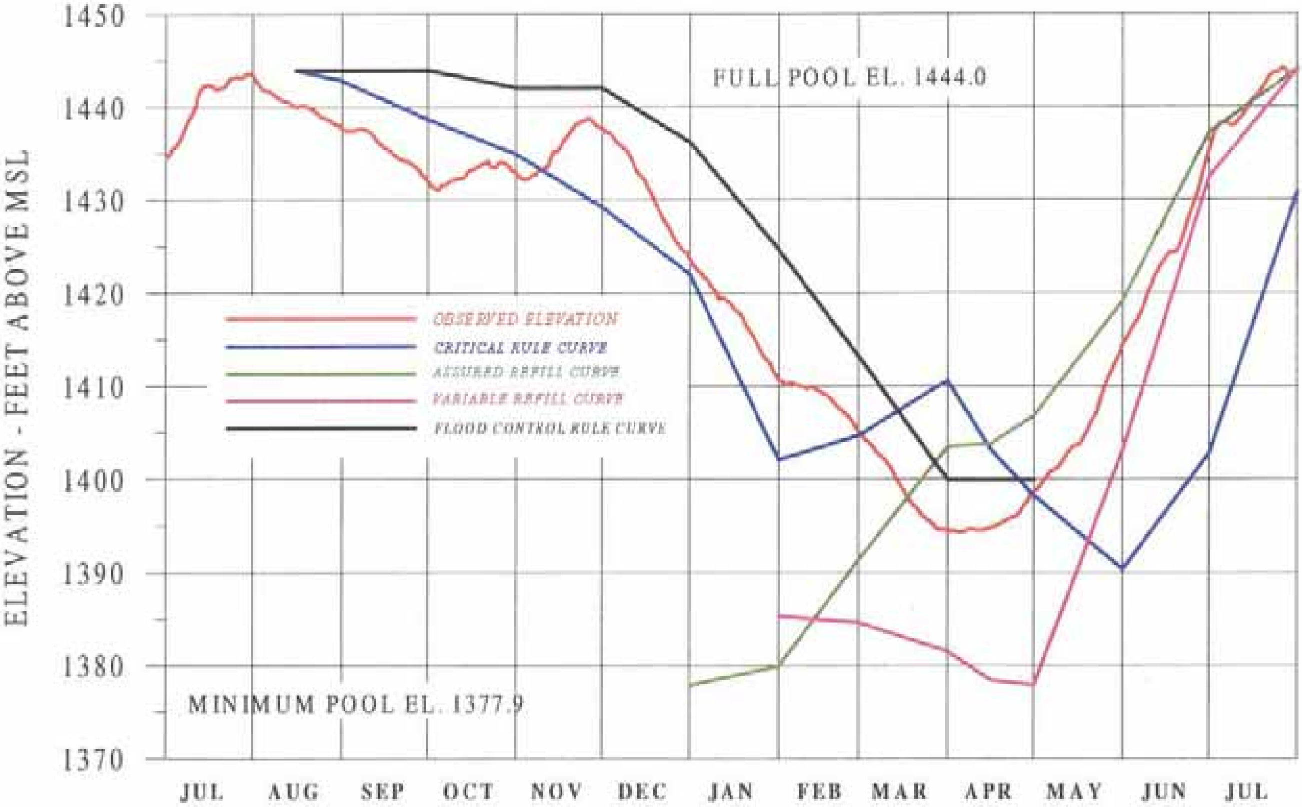


CHART 7
REGULATION OF ARROW
1 JULY 1999 - 31 JULY 2000



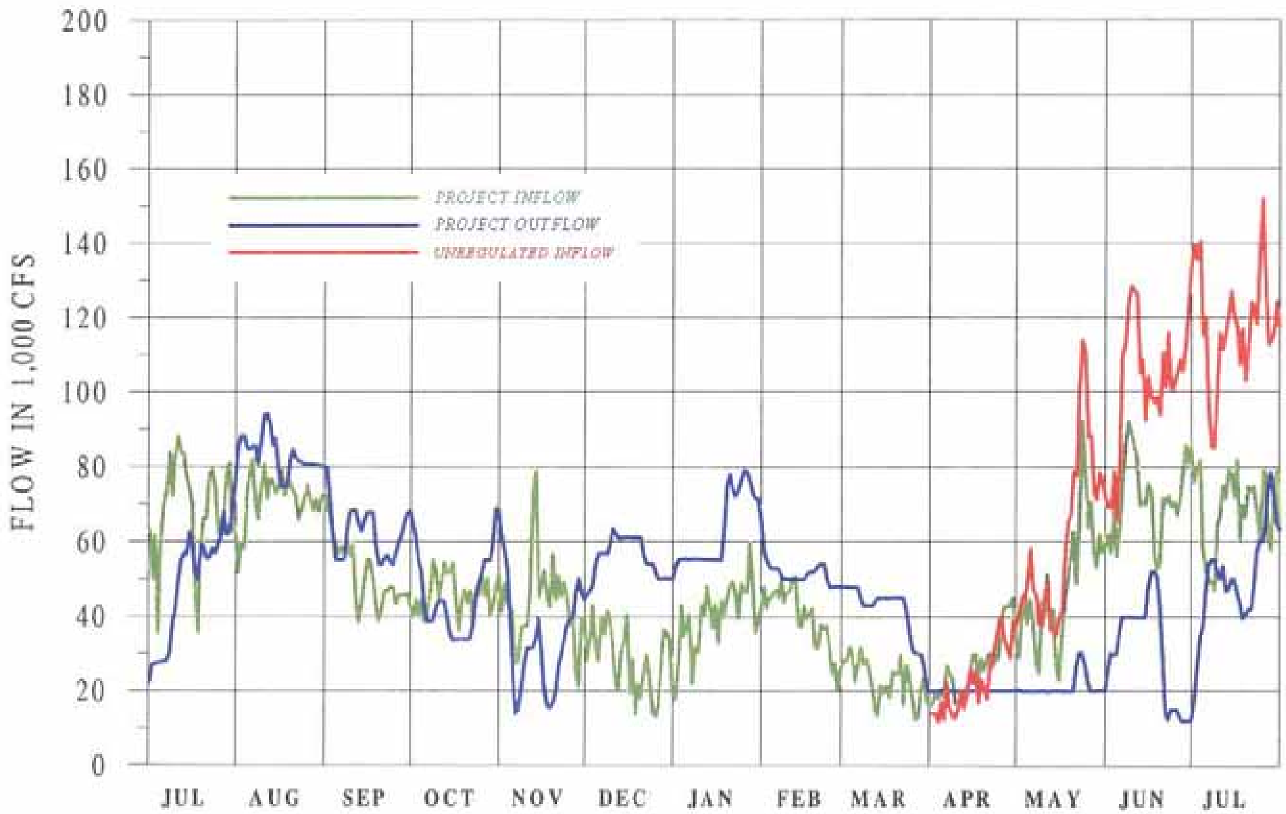
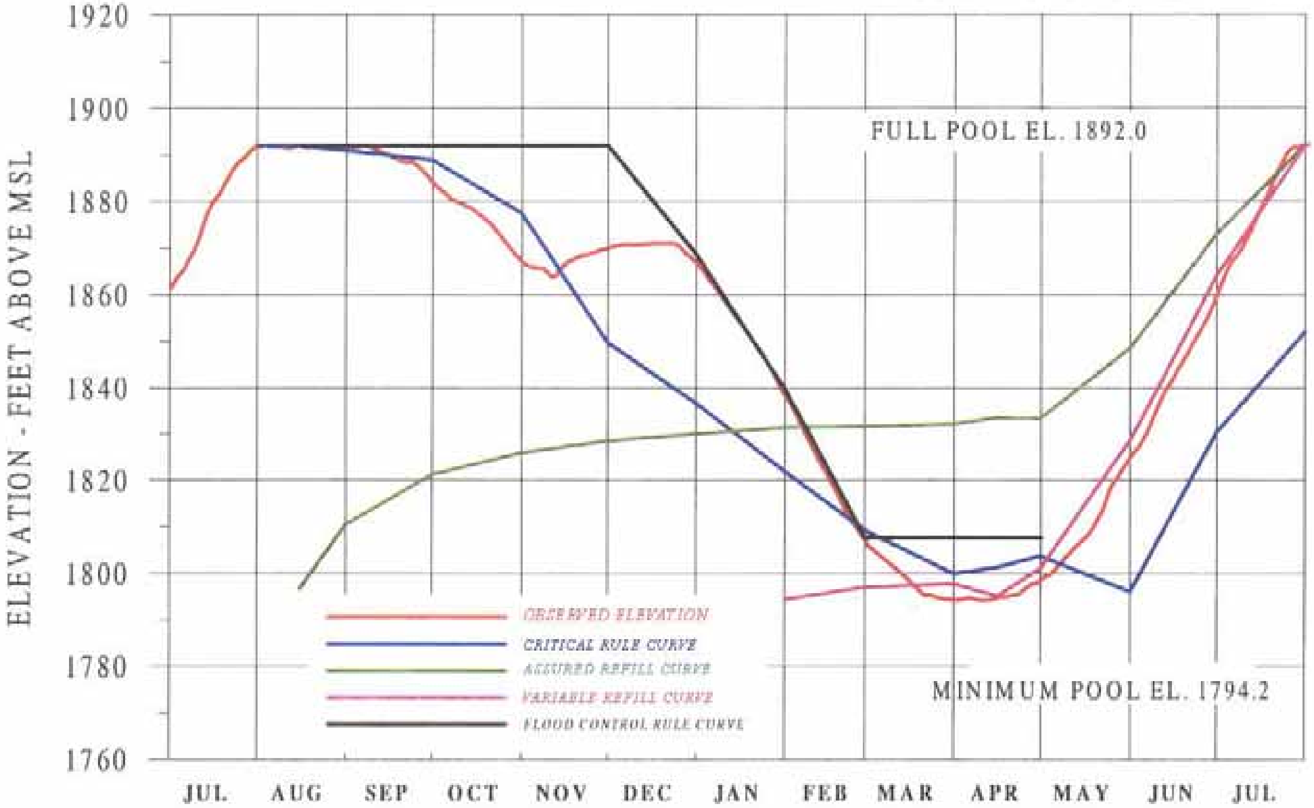


CHART 8
REGULATION OF DUNCAN
1 JULY 1999 - 31 JULY 2000



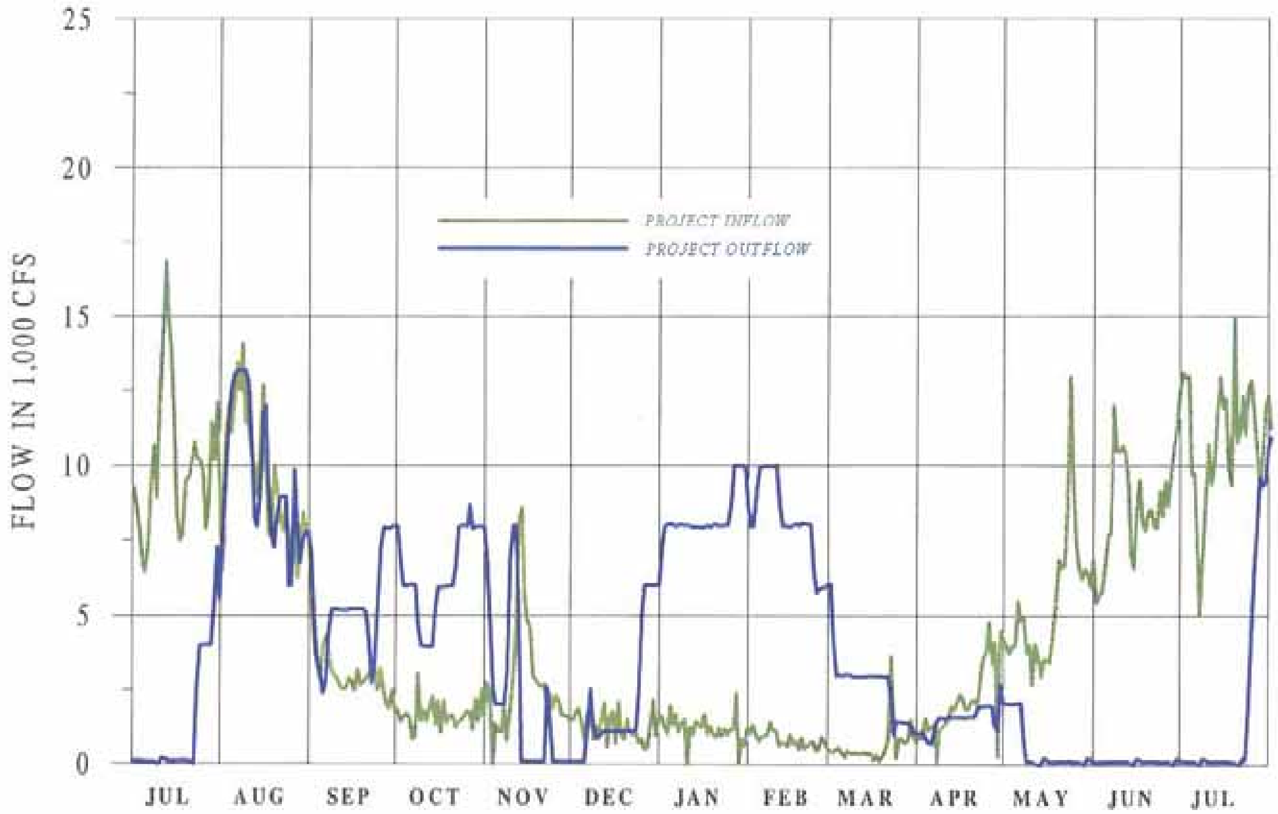


CHART 9
REGULATION OF LIBBY
1 JULY 1999 - 31 JULY 2000

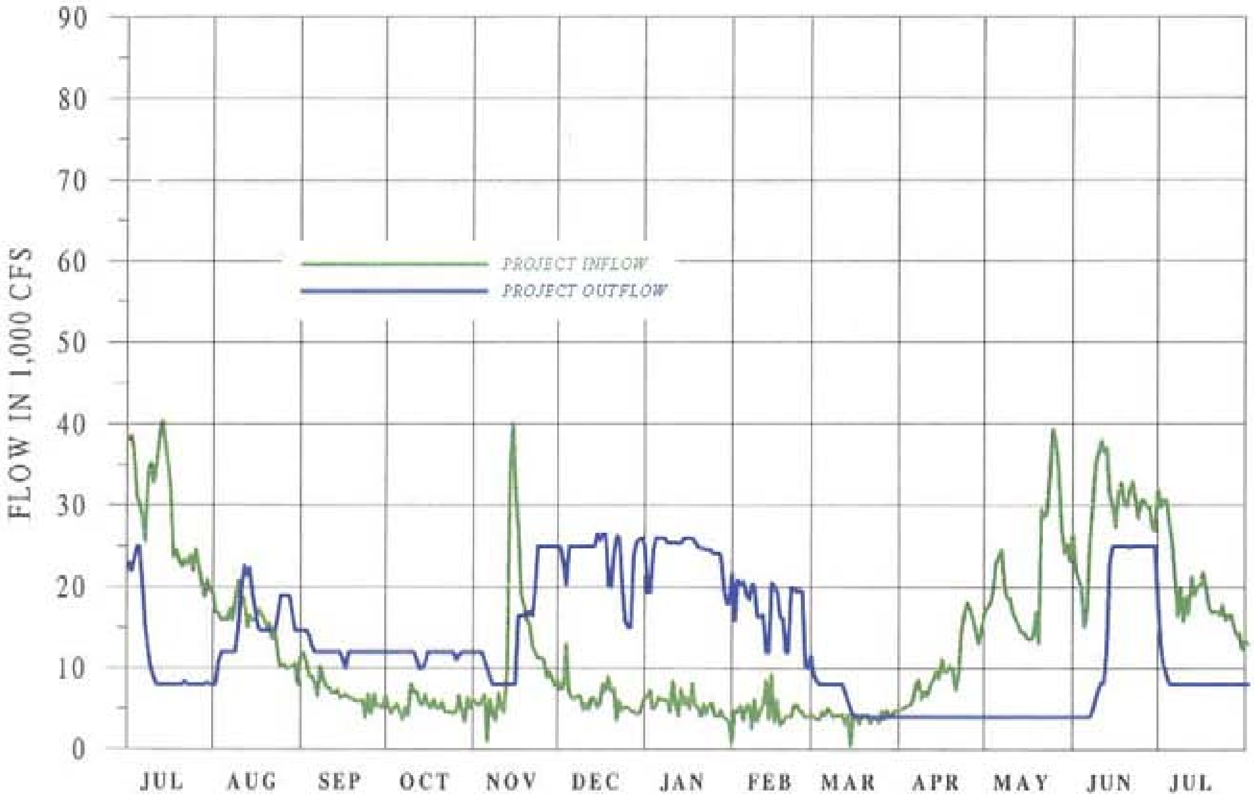
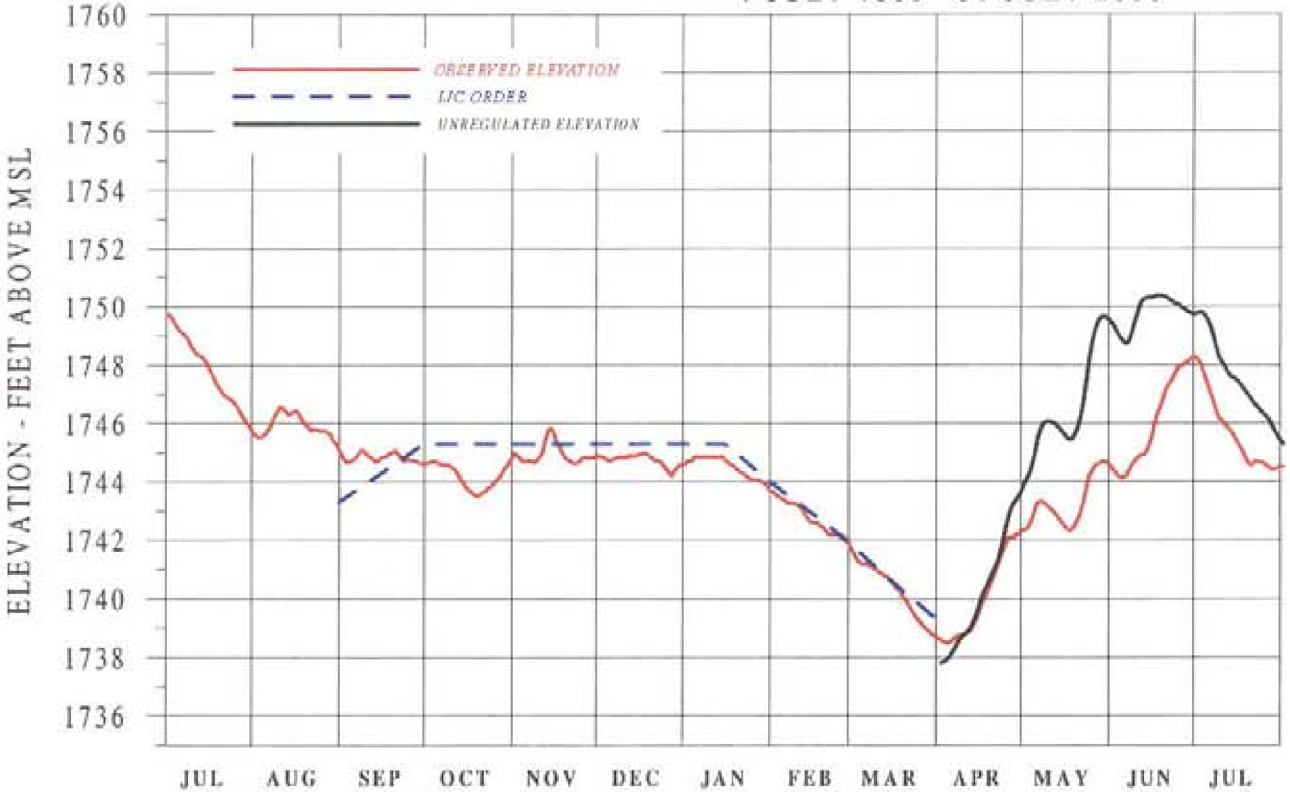


CHART 10
REGULATION OF KOOTENAY LAKE
1 JULY 1999 - 31 JULY 2000



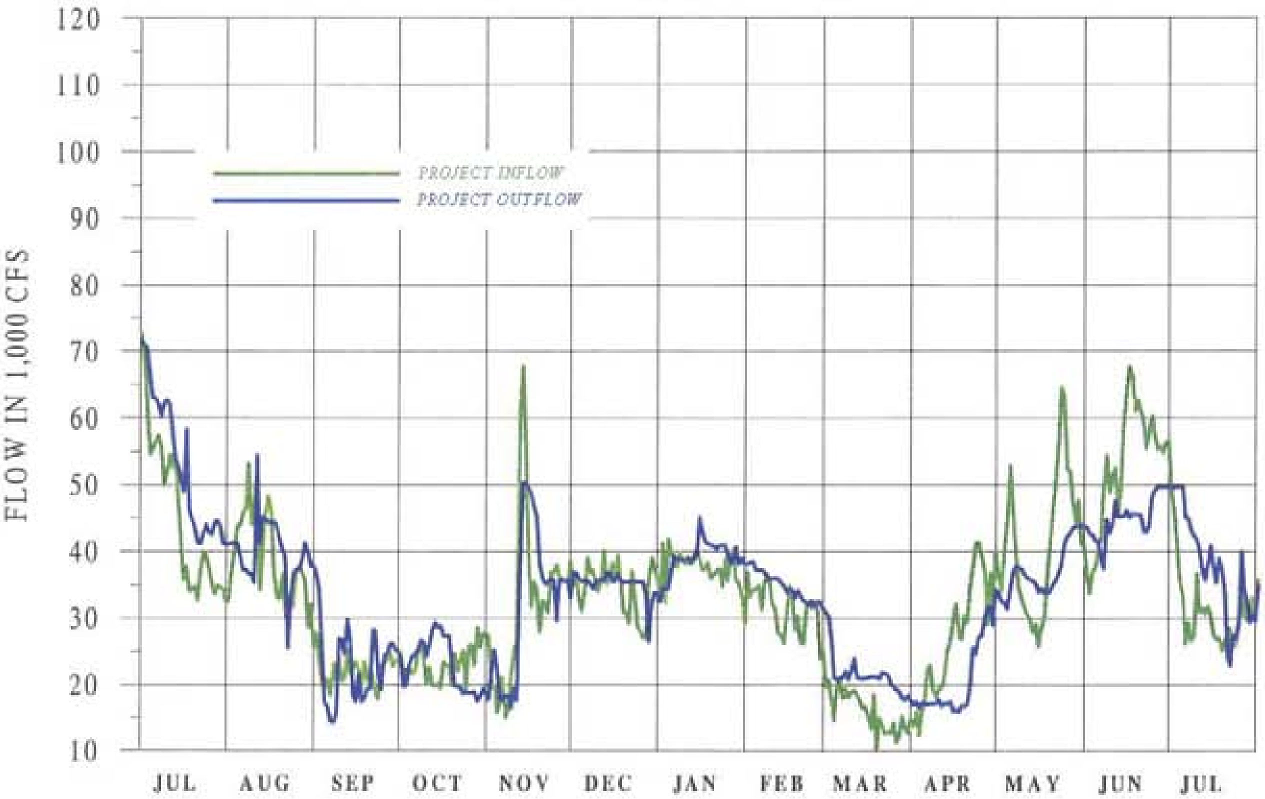


CHART 11
COLUMBIA RIVER AT BIRCHBANK
1 JULY 1999 - 31 JULY 2000

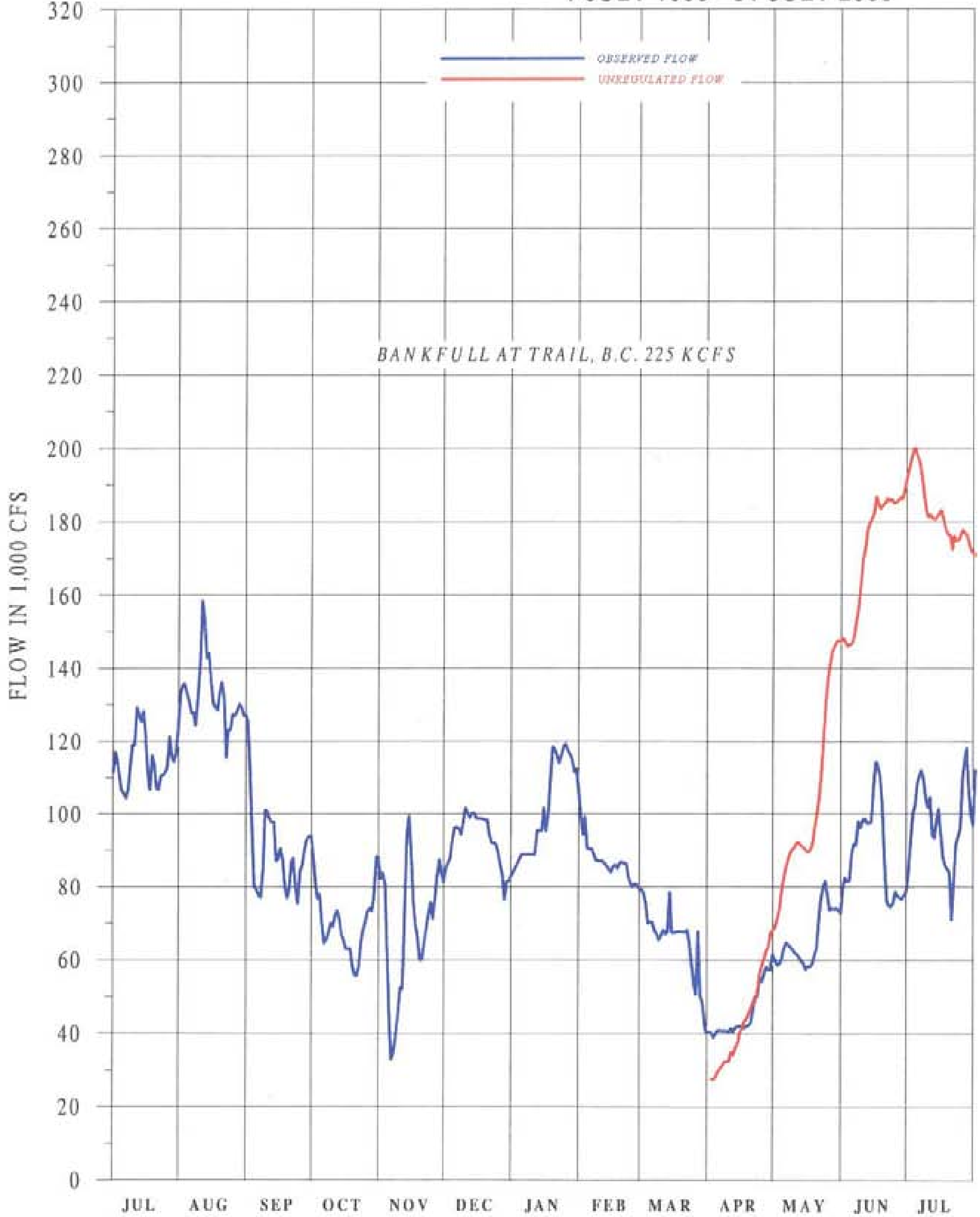
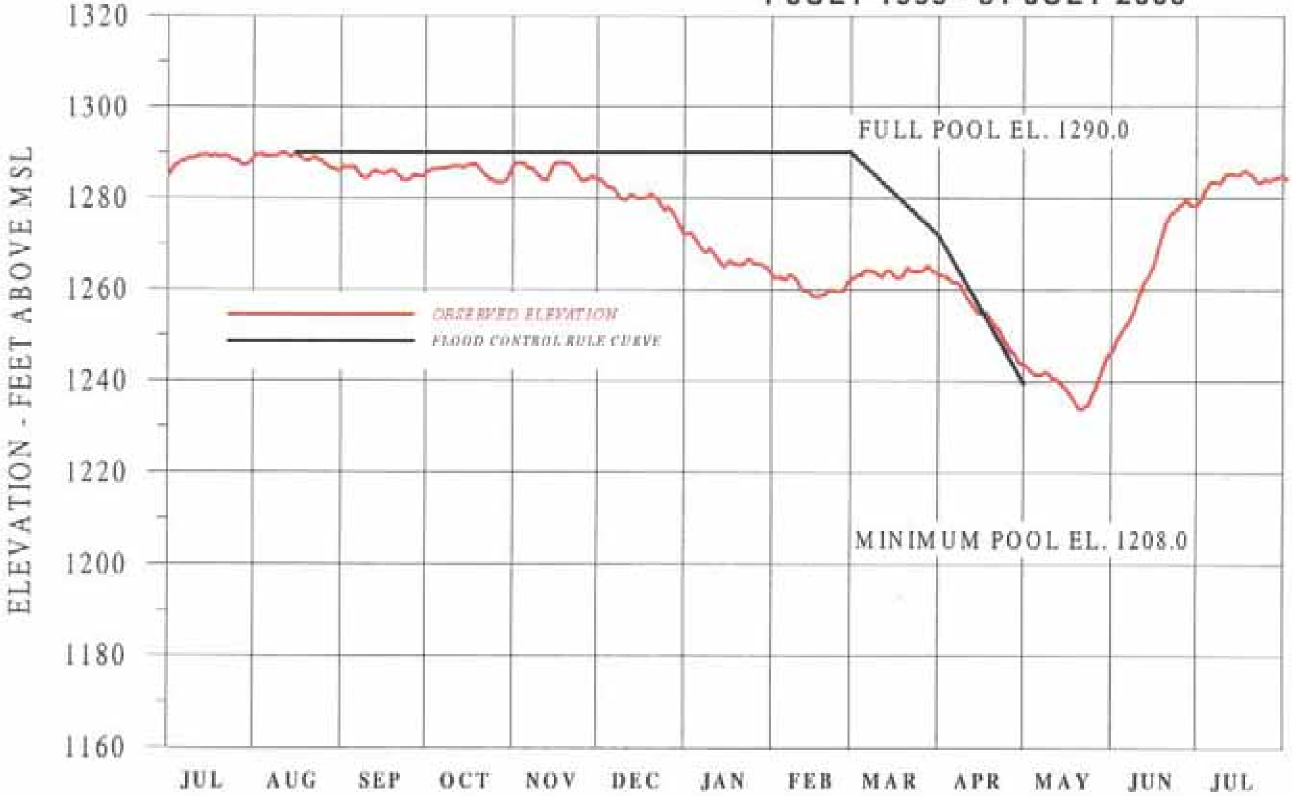


CHART 12
REGULATION OF GRAND COULEE
1 JULY 1999 - 31 JULY 2000



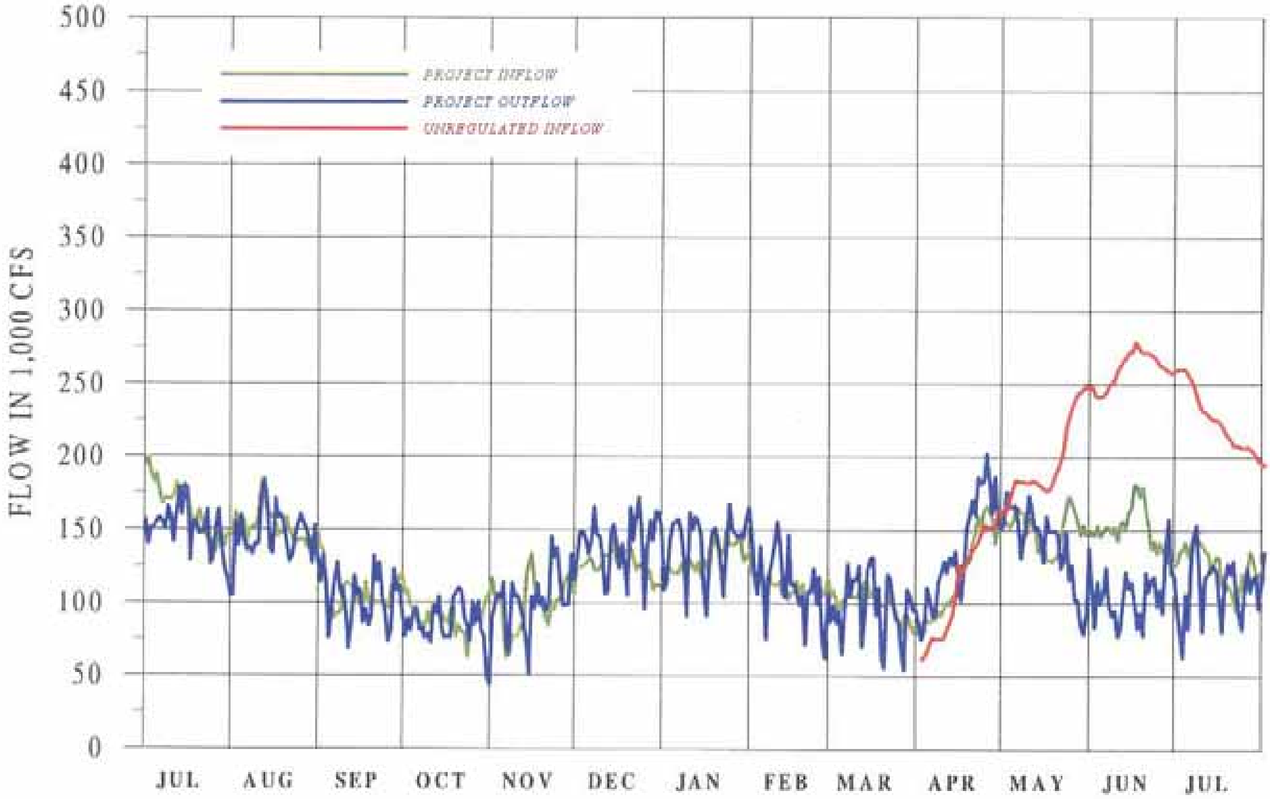


CHART13
COLUMBIA RIVER AT THE DALLES
1 JULY 1999 - 31 JULY 2000

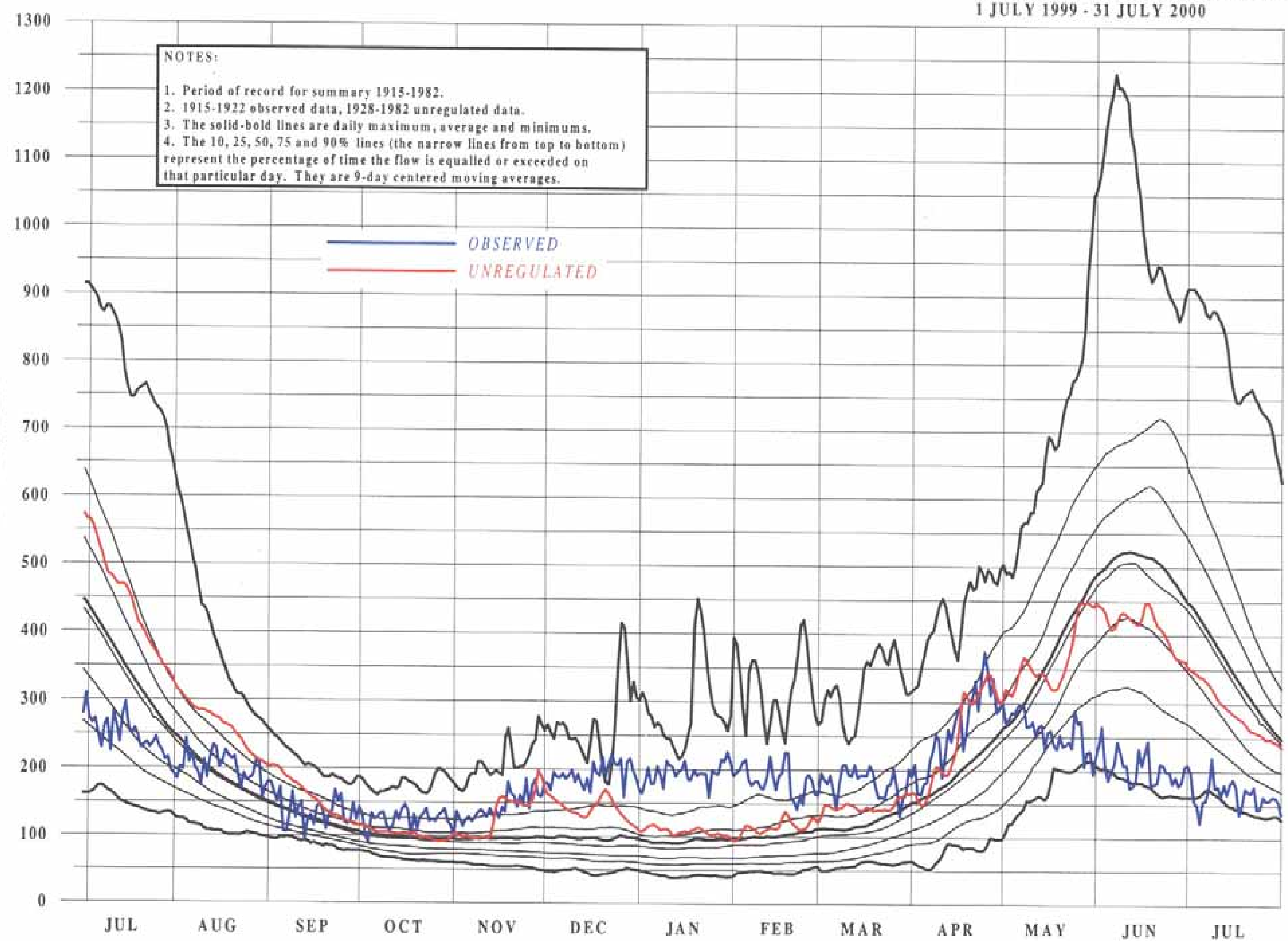


CHART 14
COLUMBIA RIVER AT THE DALLES
1 APRIL 2000 - 31 JULY 2000

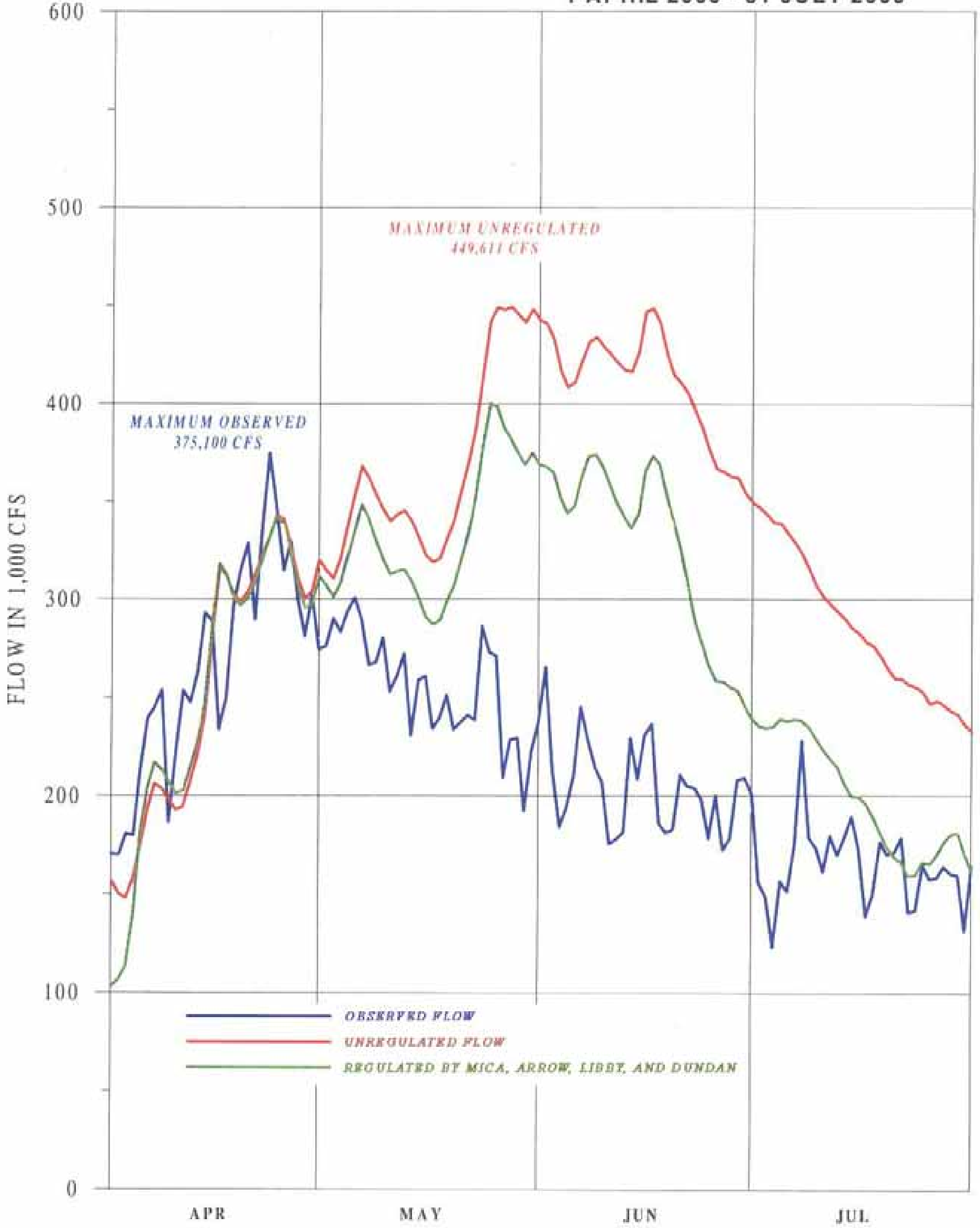


CHART 15
2000 RELATIVE FILLING
ARROW AND GRAND COULEE