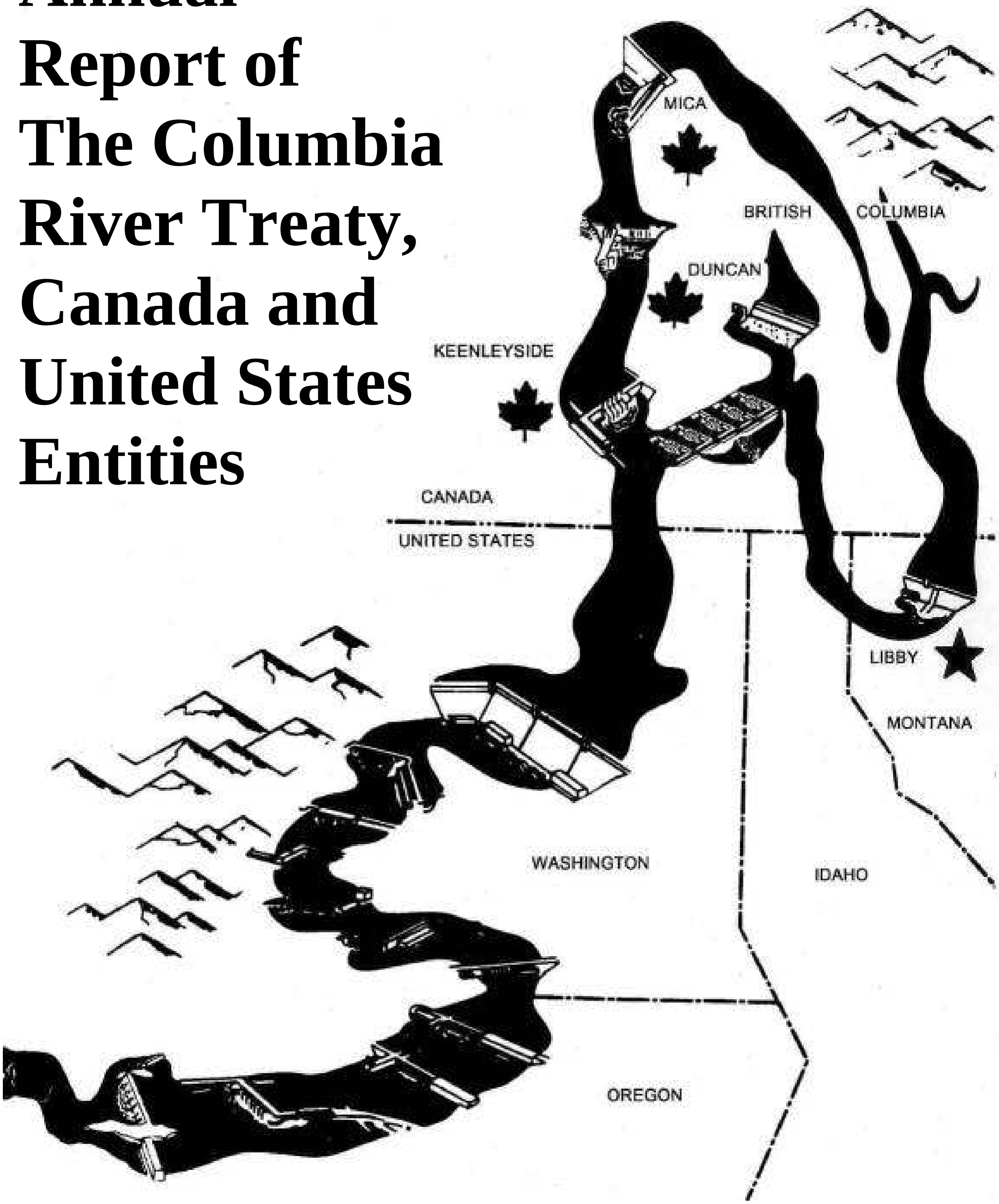
Annual Report of The Columbia River Treaty, Canada and United States Entities



1 October 2003 through
30 September 2004

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

FOR THE PERIOD

1 OCTOBER 2003 – 30 SEPTEMBER 2004

EXECUTIVE SUMMARY

General

The Canadian Treaty projects, Mica, Duncan, and Arrow were operated during the reporting period according to the 2003-2004 and 2004-2005 Detailed Operating Plans (DOP), the 2003 Flood Control Operating Plan (FCOP), and several supplemental operating agreements described below. Throughout the year, Libby was operated according to the 2003 FCOPs and the Libby Coordination Agreement (LCA) dated February 2000. From September through December 2003, Libby was operated for power purposes. Libby was also operated according to guidelines set forth in the U.S. Fish and Wildlife Service (USFWS) and the U.S. National Marine Fisheries Service (NMFS) 2000 Biological Opinions (BiOps).

Entity Agreements

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

- Columbia River Treaty Entity Agreement on the Principles and Procedures for Preparing and Implementing Hydroelectric Operating Plans for Operation of Canadian Treaty Storage, dated 16 December 2003.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2006-07 Operating Year, dated 4 February 2004.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2007-08 Operating Year, dated 4 February 2004.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2008-09 Operating Year, dated 4 February 2004.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2004 through 31 July 2005, signed 25 June 2004.

Operating Committee Agreements

Agreements approved by the Operating Committee include:

- Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the Period 27 September 2003 through 30 April 2004, signed 3 October 2003.
- Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for the Period 1 December 2003 through 31 July 2004, signed 15 December 2003.

- Columbia River Treaty Operating Committee Agreement on Implementation Procedures for Flood Control Reallocation for the 2004-2005 Operating Year, signed 28 June 2004 .

Unlike previous years, the Bonneville Power Administration (BPA) and British Columbia Hydro and Power Authority (B.C. Hydro) were unable to reach agreement on May-June storage/July-August release arrangements beyond the expiration date of the release provisions under the Non-Treaty Storage Agreement (NTSA), which expired on 30 June 2004.

System Operation

Under the 2003-2004 DOP, Canadian Treaty Storage was operated according to criteria from the 2005-2006 Assured Operating Plan (AOP) except for changes to flood control and minor changes to power operating criteria. The 2005-2006 AOP was selected instead of the 2003-2004 AOP because of mutual benefits. The 2005-2006 AOP included a flood control allocation of 5.0 million acre-feet (Maf) in Arrow and 2.08 Maf in Mica. B.C. Hydro requested a reallocation of the flood control space to operate to 4.08/3.6 Maf Mica/Arrow allocation. A process to implement the flood control reallocation was outlined by the Committee on 1 November 2002. The power operating criteria was modified for mutual benefits by raising the critical rule curves in August, September, and October, and reducing loads in August-September with a corresponding increase in load during December.

The Canadian storage system began the operating year below its composite Operating Rule Curve (ORC) content and remained below the ORC through the operating year and through the water year (WY) ending September 2004.

The 1 January 2004 water supply forecast (WSF) for the Columbia River at The Dalles for January through July was 99.3 cubic kilometers (km^3) (80.5 Maf), or 75 percent of the 1971-2000 average. This January forecast was similar to the January final forecast in 2001, which was a drought year. Precipitation was somewhat above average in October and November, but sagged to slightly below average by January through August. The seasonal precipitation for the water year was slightly above average above Grand Coulee at 104 percent of average. Streamflow at The Dalles remained below average through the water year where the seasonal average. The January through July volume at The Dalles was 102.3 km^3 (82.95 MAF), 77 percent of the 1971-2000 average. The unregulated flow at The Dalles in 2004 was 11,546 cubic meters per second (m^3/s) (407,368 cubic feet per second (cfs)) on 31 May 2004 and a regulated peak flow of 8,184 m^3/s (289,000 cfs) occurred on 29 May 2004.

The Columbia River was operated to meet chum needs below Bonneville Dam from 13 November 2003 through May 2004. U.S. reservoirs were operated to target the 10 April flood control elevation per the NMFS 2000 BiOp for juvenile fish needs, but low inflow from January through March allowed Dworshak to refill to this target. For 2004, Libby Dam released the volume of water requested by the U.S. Fish and wildlife Service to meet downstream Kootenai River white sturgeon needs. The U.S. storage projects targeted full by 30 June 2004 per the Biological Opinion, but Libby failed to refill because of the sturgeon releases in June. Projects were then drafted to the NMFS 2000 BiOp draft limits for 31 August. Libby released steady outflow through July and August per an executive agreement and drafted only 4.27 m (14 feet) from full. Dworshak Dam reached the draft limit in September.

Canadian Entitlement

During the reporting period 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 537.3 aMW at rates up to 1176 MW during 1 August 2003 through 30 September 2004. No Entitlement power was disposed directly in the U.S. during 1 August 2003 through 30 June 2004, using the specific provisions of 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” (“Disposal Agreement”).

During the course of the Operating Year, some curtailment of Canadian Entitlement occurred due to transmission constraints on either the U.S. or Canadian side of the border. In all, 30 of the 8760 hours during this time experienced full or partial curtailment due to forced outages, or 0.3% of the time for a total of 4,278 MWh out of 4,559,169 MWh scheduled to the border (0.1%).

Utilizing the section of the Disposal Agreement for mutually-agreed arrangements the Province of British Columbia disposed of Entitlement energy directly in the United States at rates of up to 400 MW per hour during the period 1 July 2004 through 31 October 2004.

Treaty Project Operation

At the end of the 2002-2003 operating year, 31 July 2003, actual Canadian Treaty storage (Canadian storage) was at 17.0 km3 (13.8 Maf) or 88.7 percent full. Canadian storage was drafted between August 2003 and March 2004, reaching a minimum of 3.6 km^3 (2.9 Maf) on 31 March 2004. Similar to the year before, Canadian storage did not refill fully during the operating year, reaching 16.9 km3 (13.7 Maf) or 88.5 percent full on 31 July 2004.

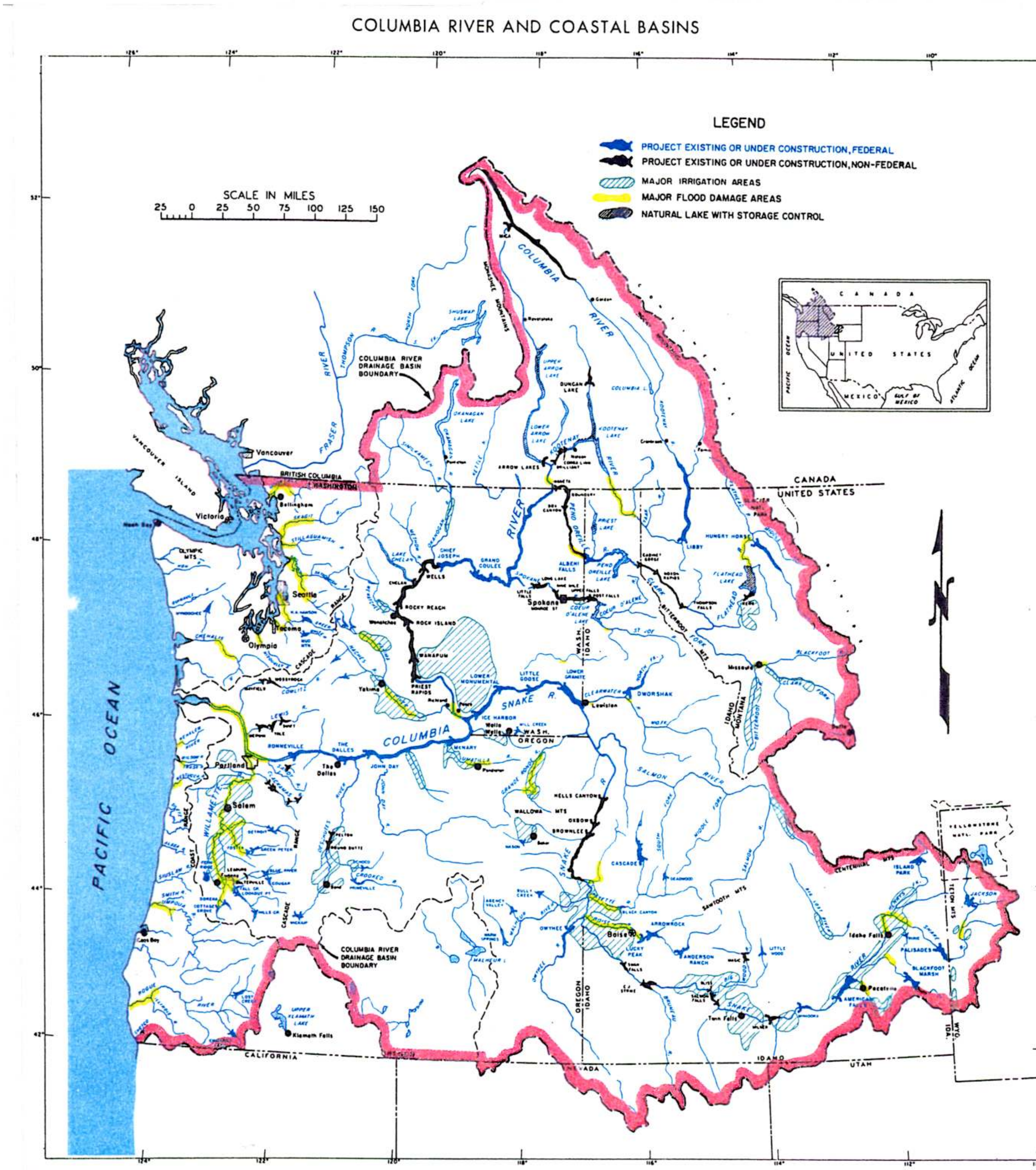
Mica (Kinbasket) reservoir, after temporarily cresting at an elevation of 744.32 meters (m) (2442.0 feet) on 23 August 2003, established a slightly higher peak elevation of 744.57 m (2442.8 feet) on 29 October 2003, 9.81 m (32.2 feet) below full pool. The higher elevation in October was the result of high inflows due to a rainfall event, setting daily and monthly rainfall records at two climate stations. From the peak elevation in October, the reservoir drafted steadily, reaching a minimum elevation of 718.47 m (2357.2 feet) on 12 April 2004. Influenced by a low initial level and below normal seasonal inflows, the reservoir refill level during 2004 was much below normal, reaching a maximum elevation of 746.9 m (2450.5 feet) on 30 September 2004, 7.47 m (24.5 feet) below full pool.

The Arrow reservoir reached its maximum elevation of 439.09 m (1440.6 feet) on 4 July 2003. The coordinated hydro system was on proportional draft from August 2003 through January 2004. This contributed to the Arrow Reservoir being drafted much earlier than normal, reaching 427.00 m (1400.9 feet) by 31 December 2003 and a minimum elevation of 425.23 m (1395.1 feet) on 31 March 2004. The reservoir refilled to a maximum elevation of 436.24 m (1431.3 feet) on 12 August 2004, 3.9 m (12.7 feet) below full pool.

The operation of Arrow Reservoir was modified during the operating year under two Operating Committee Agreements. These agreements helped to enhance the success of whitefish and rainbow trout spawning and emergence downstream of the Arrow project in British Columbia and to provide additional power and non-power benefits in the United States (U.S.).

Duncan reservoir reached a maximum elevation of 576.46 m (1,891.3 feet) on 19 Aug 2003, 0.22 m (0.7 feet) below full pool. From September 2003 through April 2004, Duncan discharge was used to supplement inflow into Kootenay Lake and to provide spawning and incubation flows for fish. The reservoir drafted to a minimum elevation of 547.24 m (1795.4 feet) on 26 April 2004, 0.37 m (1.2 feet) above empty. Reservoir discharge was reduced to the minimum of 3 m3/s (100 cfs) on 11 May to initiate reservoir refill. The reservoir refilled to a maximum elevation of 576.45 m, (1891.2 feet) on 16 August 2004, 0.23 m (0.8 feet) below full pool.

Columbia Basin Map



2004 Report of the Columbia River Treaty Entities Contents

Page

Acronyms

AER	Actual Energy Regulation
aMW	Average Megawatts
AOP	Assured Operating Plan
B.C. Hydro	British Columbia Hydro and Power Authority
BiOp	Biological Opinion
BPA	Bonneville Power Administration
CEEA	Canadian Entitlement Exchange Agreement
CEPA	Canadian Entitlement Purchase Agreement
cfs	Cubic feet per second
CRC	Critical Rule Curve
CRT	Columbia River Treaty
CRTOC	Columbia River Treaty Operating Committee
CSPE	Columbia Storage Power Exchange
DDPB	Determinations of Downstream Power Benefits
DOP	Detailed Operating Plan
FCOP	Flood Control Operating Plans
hm^3	Cubic hectometers
ICF	Initial Controlled Flow
IJC	International Joint Commission
km^3	Cubic Kilometers
ksfd	Thousand second-foot-days (=kcfs x days)
LCA	Libby Coordination Agreement
LOP	Libby Operating Plan
m	Meter
m^3/s	Cubic meters per second
Maf	Million acre-feet
MW	Megawatt
NMFS	National Marine Fisheries Service
NOAA F	NOAA Fisheries, formerly NMFS
NTSA	Non-Treaty Storage Agreement
ORC	Operating Rule Curve
PEB	Permanent Engineering Board
PEBCOM	PEB Engineering Committee
PNW	Pacific North West
STS	Summer Treaty Storage Agreement
TSR	Treaty Storage Regulation
U.S.	United States
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
VARQ	Variable discharge flood control
WSF	Water Supply Forecast
VRC	Variable Rule Curve
WY	Water Year

I INTRODUCTION

This annual Columbia River Treaty (CRT) Entity Report is for the 2004 water year (WY), 1 October 2003 through 30 September 2004. 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 2003 through 31 July 2004. The power and flood control effects downstream in Canada and the U.S. are described. This report is the thirty-eighth of a series of annual reports covering the period since the ratification of the Columbia River Treaty (CRT) in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the U.S. were constructed under the provisions of the CRT of January 1961. Treaty storage in Canada (Canadian storage) is operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the U.S. In 1964, the Canadian and the U.S. governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the CRT. The Canadian Entity is B.C. Hydro. The U.S. Entity is the Administrator/Chief Executive Officer of 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 CRT and related documents:

1. Canada is to provide 19.12 km^3 (15.5 Maf) of usable storage. This has been accomplished with 8.63 km^3 (7.0 Maf) in Mica, 8.78 km^3 (7.1 Maf) in Arrow and 1.73 km^3 (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 CRT, 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 67.6 kilometers (42 miles) into Canada and for which Canada agreed to make the land available.
7. Both Canada and the U.S. 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 and Purchase Agreement (CEPA) of 13 August 1964, Canada sold its entitlement to downstream power benefits to the U.S. for 30 years beginning at Duncan on 1 April 1968, at Arrow on 1 April 1969, and at Mica on 1 April 1973. That sale has now expired, and all Canadian Entitlement is being either delivered to the Canada-U.S. border or sold directly in the United States.
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 CRT.

II TREATY ORGANIZATION

Entities

There was one meeting of the CRT Entities (including the Canadian and U.S. Entities and Entity Coordinators) during the year on the morning of 11 February 2004 in Portland, Oregon. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY

Mr. Stephen J. Wright, Chairman
Administrator & Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

Brigadier General William T. Grisoli,
Member
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY

Mr. Robert G. Elton, Chair
President & Chief Executive Officer
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

Mr. Elton replaced Mr. Larry Bell as Chair of the Canadian Entity on 26 May 2004.

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

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the CRT.
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 PEB in the discharge of its functions.
5. Prepare hydroelectric and Flood Control Operating Plans (FCOPs) for the use of Canadian storage.
6. Prepare and implement Detailed Operating Plans (DOPs) that may produce results more advantageous to both countries than those that would arise from operation under Assured Operating Plans (AOPs).

Additionally, the CRT 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 CRT. The Canadian Entity for Entitlement Return is the government of the Province of British Columbia.

Entity Coordinators & Secretaries

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

The members are:

UNITED STATES ENTITY COORDINATORS

Gregory K. Delwiche
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

Karen Durham-Aguilera
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR

Kenneth R. Spafford
Technical Strategic Advisor,Generation
B.C. Hydro
Burnaby, 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
Integrated Operation and Risk Mgmt
Generation
B.C. Hydro
Burnaby, British Columbia

Columbia River Treaty Operating Committee

The Columbia River Treaty Operating Committee (CRTOC) was established in September 1968 by the Entities, and is responsible for preparing and implementing operating plans as required by the CRT, making studies and otherwise assisting the Entities as needed. The CRTOC 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

Kelvin Ketchum, B.C. Hydro, Chair
Dr. Thomas K. Siu, B.C. Hydro
Allan Woo, B.C. Hydro
Herbert Louie, B.C. Hydro

The CRTOC met six times during the reporting period to exchange information, approve work plans, and discuss and agree on operating plans and issues. The meetings were held every other month alternating between Canada and the U.S. During the period covered by this report, the CRTOC:

- Coordinated the operation of the CRT storage in accordance with the current hydroelectric and FCOPs;
- Scheduled delivery of the Canadian Entitlement according to the CRT and related agreements;
- Completed studies and documents for the 2006-07, 2007-08 and 2008-09 AOPs/Determinations of Downstream Power Benefits (DDPB);
- Completed the 1 August 2004 through 31 July 2005 DOP; and
- Completed three supplemental operating agreements.

These aspects of the CRTOC's work are described in following sections of this report, which have been prepared by the CRTOC with the assistance of others.

In addition to the above tasks, the CRTOC completed its efforts to develop a streamlined method for simplifying the extensive procedures and studies currently used to prepare the AOP/DDPB. The CRTOC also completed and published updated irrigation depletion estimates used to adjust historic streamflows for the AOP/DDPB studies.

Columbia River Treaty Operating Committee at the 20 July 2004 Meeting
[Pictured from left to right: Tom Siu (B.C. Hydro, Member), John Hyde (BPA, Member), Kelvin Ketchum (B.C. Hydro, Co-Chair), Rick Pendergrass (BPA, Co-Chair), Bill Branch (USACE, Co-Chair), Doug Robinson (B.C. Hydro, Canadian Entity Secretary), Tony White, (BPA, U.S. Entity Secretary), Allan Woo (B.C. Hydro, Member), Herbert Louie(B.C. Hydro, Member), Not shown Cindy Henriksen (USACE, Member)]

Columbia River Treaty Hydrometeorological Committee

The Columbia River Treaty Hydrometeorological Committee (CRTHC) 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 Brooks, USACE Co-Chair	Wuben Luo, B.C. Hydro, Member

Although the primary responsibility of the Committee is the planning and monitoring of the operation of the data facilities, a significant part of the 2003-04 year was focused on evaluating the new Libby water supply forecast procedures developed by the Corps of Engineers. The CRTHC provided technical guidance and evaluation of the new procedures, resulting in recommendations to the CRTOC for incorporating the new forecasts into Treaty procedures. Randy Wortman with the Corps of Engineers developed the equations, including two early-season forecast procedures for November and December. After careful evaluation and assessment, the December through June forecast equations were recommended to the CRTOC for adoption. The CRTOC accepted the December through June equations for Treaty procedures in February of 2004. The CRTHC also recommended the Dworshak early season forecast, which was also approved by the CRTOC.

In addition to evaluating the new forecast procedures, the CRTHC took on the responsibility of developing and maintaining the documentation of the forecast procedures for Mica, Arrow, Duncan, Libby, Dworshak, and Hungry Horse (project owner forecast procedures). A compiled notebook was made available to the CRTHC and CRTOC in July 2004.

The summer of 2004 also marked the completion of the 2000 Level Modified Flows Study which fulfilled the CRT obligation to update irrigation depletions. Although BPA undertook the development of the study, the data submittal and review of the study was a cooperative effort from all Treaty committees and staff.

In terms of operational issues throughout the year, the CRTHC dealt with the following:

1. Heavy rainfall in British Columbia during the month of October caused the fall precipitation parameters in the water supply forecast procedures to take on more influence than hydrologically reasonable. A coordinated conference call, including the Northwest River Forecast Center, resulted in an agreement to use normal values for precipitation rather than the actual observed. The use of normal precipitation for October persisted throughout the water supply season.
2. On several occasions, discrepancies appeared between the observed Canadian streamflow data submitted for TSR purposes and the observed recorded by BC Hydro. Canadian observed values are submitted by BPA. The source of the observed data for the Canadian projects had been the Northwest River Forecast Center's Runoff processor program. In evaluating the situation, it was found that

the Runoff processor did not always have the same data as BC Hydro. In order to determine the problem, BC Hydro began sending daily inflow, outflow and elevation data to the Northwest River Forecast Center. The issue is still not resolved, however, interim coordination of submittals is in place until the data differences can be eliminated.

3. Station closures and changes continued to be an issue in 2004. The problem was primarily focused in British Columbia, with causes ranging from forest fire site destruction to funding reductions. In general, the shrinking of the network is an issue and a threat that will continue into 2005 and will have to be carefully monitored for impacts to Treaty planning and operations.

Permanent Engineering Board

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

UNITED STATES SECTION	CANADIAN SECTION
Stephen L. Stockton, Chair San Francisco, California	Tom Wallace, Member, Chair Ottawa, Ontario
Ronald H. Wilkerson, Member Missoula, Montana	Tim Newton, Member Vancouver, British Columbia
Robert A. Pietrowsky, Member-Nominee Washington, D.C.	James Mattison, Alternate Victoria, British Columbia
George E. Bell, Alternate Portland, Oregon	David E. Burpee, Alternate & Secretary Ottawa, Ontario
Jerry W. Webb, Secretary Washington, D.C.	

Robert A Pietrowsky, Member-Nominee, replaced Earl E. Eiker, Member-Nominee, and Jerry W. Webb replaced Robert A. Bank as PEB secretary.

Under the CRT, the PEB is to assemble records of flows of the Columbia River and the Kootenay River at the international boundary. The PEB is also to report to government if there is a substantial deviation from the hydroelectric or Flood Control Operating Plan (FCOP), 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 CRT 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.
- Investigate and report on any other CRT 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, Operating Committee agreements, updates 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 11 February 2004 in Portland, Oregon, where the Entities briefed the PEB on the preparation and implementation of operating plans, the delivery of the Canadian Entitlement, and other topics requested by the Board.

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	CANADIAN SECTION
Jerry W. Webb, Chair Washington, D.C.	Roger S. McLaughlin, Chair Victoria, British Columbia
Michael S. Cowan, Member Lakewood, CO	Eve Jasmin, Member Toronto, Ontario
Kamau B. Sadiki, Member Portland, OR	Ivan Harvie, Member Calgary, Alberta
D. James Fodrea, Member Boise, ID	Dr. G. Bala Balachandran, Member Victoria, British Columbia

Jerry W. Webb replaced Robert A. Bank.

The PEBCOM met with the Operating Committee on 8 October 2003 in Portland, OR.

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 CRT, that dispute may be referred to the IJC for resolution.

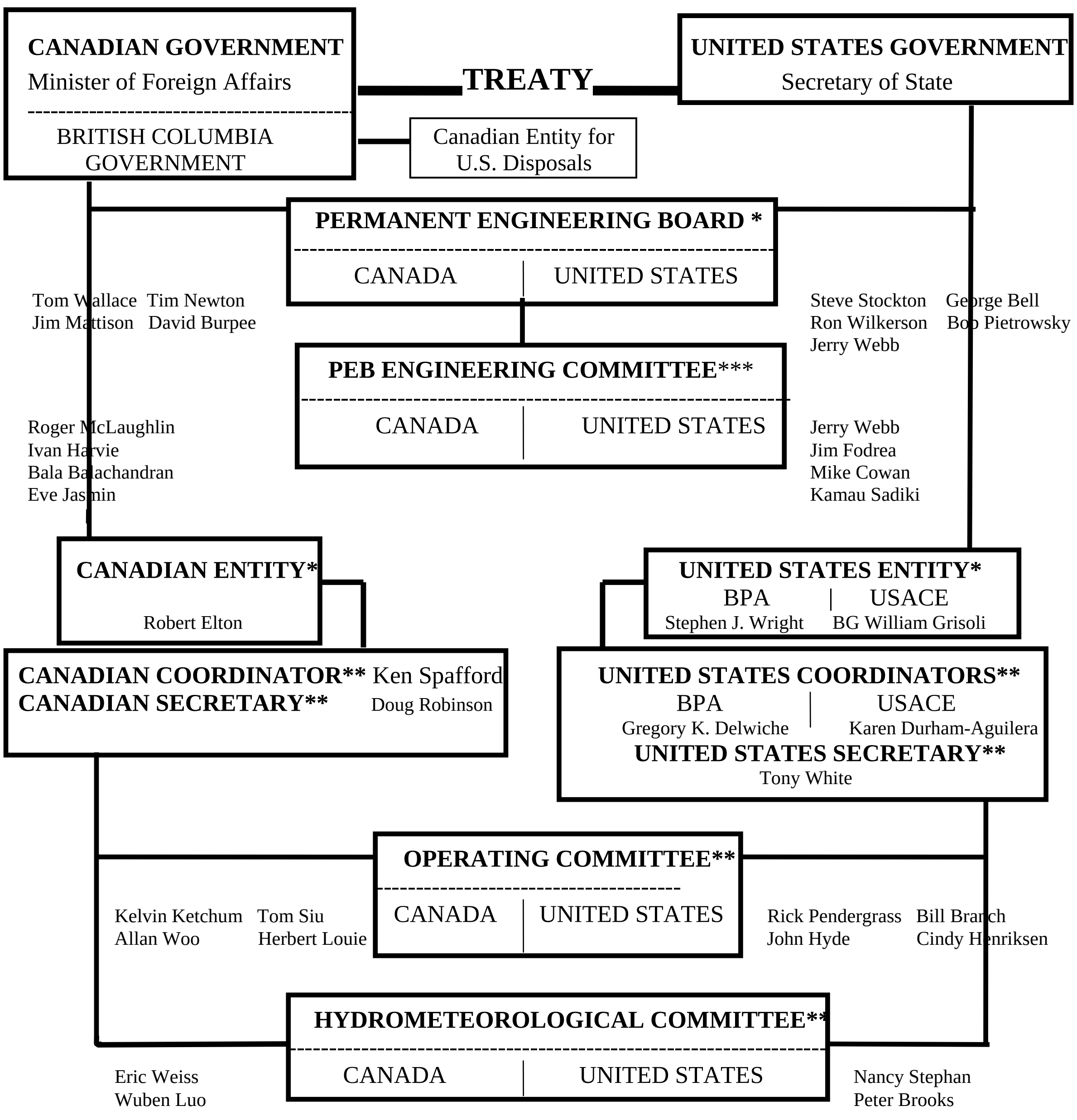
The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC informed. There are three such boards west of the continental divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, and the International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

The U.S. Section Chair is Dennis L. Schornack of Williamston, MI. The Canadian Section Chair is The Right Honorable Herb Gray of Ottawa, Canada. Canadian members are Mr. Robert Gourd of Montreal, QUE. and Mr. Jack P. Blaney of Vancouver, B.C. U.S. members are Ms. Irene B. Brooks of Seattle, WA and Mr. Allen I. Olson of Edina, MN.

Presentations

During the period covered by this report, CRT personnel made presentations about the history, structure, operations, challenges and communications associated with the CRT to visitors from the Peoples' Republic of China, Turkey, the Nile Basin, the Northwest Power Planning Council staff, the Columbia Basin Trust staff, and several academic and civic groups.

Columbia River Treaty Organization



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

III OPERATING ARRANGEMENTS

Power and Flood Control Operating Plans

The CRT requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the CRT:

(1) Stipulates that the U.S. Entity will submit FCOPs;

(2) States 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; and

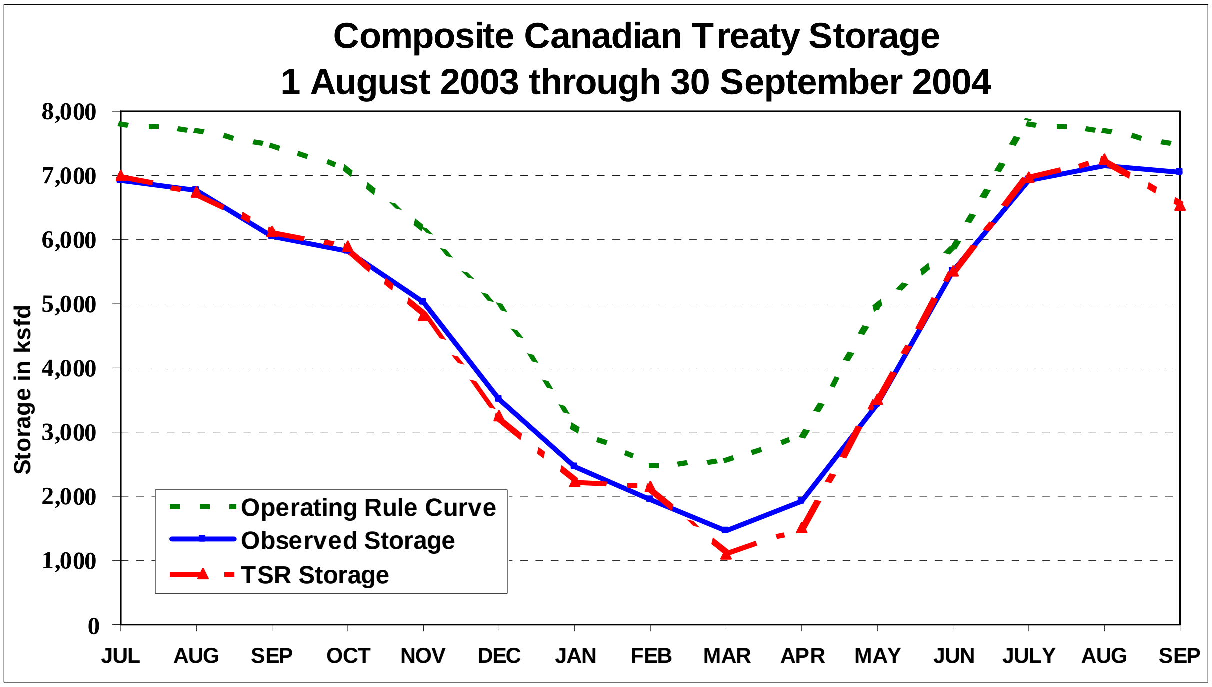
(3) Provides for the development of hydroelectric operating plans for the sixth succeeding year to furnish the Entities with an AOP for Canadian Storage.

Article XIV.2.k of the CRT provides that a DOP be developed that may produce results more advantageous than the AOP. The Protocol to the CRT provides further detail and clarification of the principles and requirements of the CRT.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage", signed December 2003, together with the "Columbia River Treaty Flood Control Operating Plan" dated May 2003, establish and explain the general criteria used to develop the AOP and DOP and operate CRT storage during the period covered by this report.

The planning and operation of CRT Storage as discussed on the following pages is for the operating year, 1 August 2003 through 31 July 2004. The operation of Canadian Storage was determined by the 2003-4 DOP and several supplemental operating agreements. The DOP required a semi-monthly Treaty Storage Regulation (TSR) study to determine end-of-month storage obligations prior to any supplemental operating agreements. The TSR included all operating criteria from, and was based on, the Step I Joint Optimum Power Hydroregulation Study from the 2005-2006 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period, August 2003 through September 2004.

The following chart compares the actual operation of the composite Canadian Treaty Storage to the results of the DOP TSR study. Because of low Mica reservoir levels at the beginning of the operating year, the TSR was regulated to draft below the Operating Rule Curve (ORC) throughout the operating year. The actual operation of the CRT storage was near the TSR levels during most of the year, except for storage above TSR levels from November through January 2003, March through April 2004, and September 2004. These deviations from the TSR levels were agreed to for mutual benefits and are described in detail in Section VI.



Assured Operating Plans

During the reporting period, the Entities completed the 2006-2007, 2007-2008, and 2008-2009 AOP/DDPB's using the streamline methods developed in the prior year and the procedures described in the 2003 Principles and Procedures document. The streamline methodology meets all criteria defined in the CRT Annexes A & B, and Protocol and will be documented in an Appendix to be added to the Principles and Procedures.

These AOP's establish ORCs, Critical Rule Curves (CRCs), Mica Operating Criteria, Arrow Project Operating Criteria, and other operating criteria included in the Step I Joint Optimum Power Hydroregulation Study, to guide the operation of Canadian storage. The ORCs were derived from CRCs, Assured Refill Curves, Upper Rule Curves (Flood Control), Variable Refill Curves and Operating Rule Curve Lower Limits, consistent with flood control requirements, as described in the 2003 Principles and Procedures document. They provide guidelines for draft and refill under a wide range of water conditions. The Flood Control Rule Curves conform to the 2003 FCOP, and are used to define an upper limit to the operation of Canadian storage. All of these AOP's use the 4.08/3.6 Maf Mica/Arrow flood control allocation. The CRCs are used to apportion draft below the ORC when the TSR determines additional draft is needed to meet the Coordinated System firm energy load carrying capability.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits (DDPB) resulting from Canadian Treaty storage is made in conjunction with the AOP according to procedures defined in the CRT, Annexes, and Protocol. The total CRT DDBP as a result of the operation of Canadian storage for both operating years 2003-2004 and 2004-2005 were determined to be 1,074.6 MW average annual usable energy and 2,352.9 MW dependable capacity, respectively.

In conjunction with the 2006-2007, 2007-2008, and 2008-2009 AOP’s, the Entities completed the 2006-2007, 2007-2008, and 2008-2009 DDPB’s.

Canadian Entitlement

The Canadian Entitlement to downstream power benefits was sold to the Canadian Storage Power Exchange (CSPE), a nonprofit consortium of 41 Northwest public and private utilities, in accordance with the Canadian Entitlement Purchase Agreement (CEPA) dated 13 August 1964. This is required for a period of thirty years following the CRT-specified required completion date for each Canadian storage project. The purchase of the Canadian Entitlement under CEPA expired 31 March 1998 for Duncan, 31 March 1999 for Arrow, and 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 (as revised 29 March 1999). For the period 1 August 2003 through 30 September 2004, the amount returned for Duncan, Arrow, and Mica, before losses, was 537.3 aMW of energy, scheduled at rates up to 1176 MW. The Canadian Entitlement obligation was determined by the 2003-2004 and 2004-2005 AOP/DDPB’s even though the 2003-2004 and 2004-2005 DOP’s were based on the 2005-2006 AOP.

For the period 1 July 2004 through 30 September 2004, the Canadian Entitlement’s owner, the Province of British Columbia, entered into a short-term disposal in the United States of up to 400 MW, scheduled to terminate on 31 October 2004, at which time that power will once again be returned to the U.S.-Canada border.

Detailed Operating Plans

During the period covered by this report, the Operating Committee used the 1 August 2003 through 31 July 2004 "Detailed Operating Plan for Columbia River Treaty Storage", dated July 2003 and the 1 August 2004 through 31 July 2005 DOP, dated June 2004, to guide storage operations. These DOPs established criteria for determining the ORCs, proportional draft points, and other operating data for use in actual operations. The 2003-2004 DOP was based on the 2005-2006 AOP instead of the 2003-2004 AOP because of mutually beneficial changes in operating criteria. The respective AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects, were used to develop the Treaty Storage Regulation (TSR) studies for implementation of operations. The changes were minor and were mainly updates to flood control rule curves, hydro-independent data, raising the critical rule curves in August-October and lowering loads in August-September with a balancing increase in December and a maximum January average monthly outflow limit at Arrow of 65,000 cfs.

The TSR studies were updated twice monthly throughout the operating year, and together with supplemental operating agreements, defined the end-of-month draft rights for Canadian storage. The Variable Rule Curves (VRCs) and flood control requirements subsequent to 1 January 2004 were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby for the 2003-2004 operating year are shown in Tables 2 through 5. The tabular calculation in Table 5 for Libby's VRCs were used in the TSR study only and are not used in real time operations.

The Operating Committee directed the regulation of the Canadian storage, on a weekly basis throughout the year, in accordance with the applicable DOPs and supplemental operating agreements made there under.

Libby Coordination Agreement

During the period covered by this report, the Libby Coordination Agreement (LCA) procedures allowed the Canadian Entity to provisionally draft Arrow reservoir and exchange power with the U.S. Entity, and required delivery to the U.S. Entity of one (1) aMW, shaped flat, over the entire operating year. In accordance with the LCA, the Libby Operating Plan (LOP) was last updated by the U.S. Army Corps of Engineers (USACE) in 2002. The LOP update was a result of a new methodology to measure flow augmentation for sturgeon at Libby Dam. The new methodology included a tiered flow approach based on the water supply forecast. The measurement made is the result of outflow at Libby Dam rather than a measurement at Bonners Ferry, Idaho, which includes local inflow.

Entity Agreements

During the period covered by this report, five joint U.S.-Canadian arrangements were approved by the Entities:

Date Agreement Signed by Entities	Description
16 December 2003	Columbia River Treaty Entity Agreement on the Principles and Procedures for Preparing and Implementing Hydroelectric Operating Plans for Operation of Canadian Treaty Storage
4 February 2004	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2006-07 Operating Year
4 February 2004	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2007-08 Operating Year
4 February 2004	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2008-09 Operating Year
25 June 2004	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2004 through 31 July 2005.

The Principles and Procedures document shown above is the first update since 1991.

Operating Committee Agreements

During the period covered by this report, the Operating Committee approved three joint U.S.-Canadian agreements:

Date Agreement Signed by Committee	Description	Authority
3 October 2003	Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning For the Period 27 September 2003 through 30 April 2004	Detailed Operating Plan, 1 August 2003 through 31 July 2004, approved 25 June 2003 and dated June 2003
15 December 2003	Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for the Period 1 December 2003 through 31 July 2004	Detailed Operating Plan, 1 August 2003 Through 31 July 2004, Approved 25 June 2003 and dated June 2003
28 June 2004	Columbia River Treaty Operating Committee Agreement on Implementation Procedures for Flood Control Reallocation for the 2004-2005 Operating Year	Detailed Operating Plan, 1 August 2004 through 31 July 2005, approved 25 June 2003 and dated June 2003

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 CRT storage. The Entity agreement dated 28 June 2002, gave approval for B.C. Hydro and BPA to extend the expiration date of the contract by one year, from 30 June 2003 to 30 June 2004, which was done. Two Mid-Columbia parties, Eugene Water and Electric Board and Tacoma Utilities, elected to extend their NTSA Agreement with BPA for the same one-year period.

As per contract terms, release rights under the Non-Treaty Storage Agreement terminated effective 30 June 2004. Extended Provisions of the Agreement require that active Non-Treaty Storage Space in Mica be refilled within 7 years (Deadline: 30 June 2011).

IV WEATHER AND STREAMFLOW

Weather

After a very warm and dry summer, fall 2003 opened on a cooler note, with October and November precipitation above normal in Canada and across northern Idaho and western Washington. All other areas carried on the theme of the summer, with below normal precipitation amounts. For October through November, precipitation was 92 percent of normal at Columbia above Grand Coulee, 60 percent of normal at the Snake River above Ice Harbor, and 83 percent of normal at Columbia above The Dalles. A continental airmass entered the region mainly late in October, bringing colder than normal temperatures, and drier conditions in northern regions. This pattern held through November, producing many low temperature records, some of which occurred in several spots west of the Cascades. Although not a record, Spokane registered –9 degF (-22.8 degC) on 22 November 2003. For the lead fall months, regional temperatures departed +3.7 degF (+6.8 degC). Warmer weather was on the way, though, as the storm track changed into December, bringing more maritime air to the region, and consequently wetter weather.

Most of December was wetter-than-normal as this maritime, westerly flow brought in frequent fronts. The core of the storm track ran across the U.S. part of the basin, rather than in Canada. As such, precipitation was 131 percent of normal at the Snake River above Ice Harbor, 98 percent of normal at Columbia above The Dalles, but 73 percent of normal at Columbia above Grand Coulee. While much of the month was mild, another cold, continental airmass moved south into the region later in the month. It combined with the antecedent moist flow to bring snow into the Willamette Valley, the north Oregon Coast, and through western Washington. Thus began a turn toward a very cold start to winter, even though the mild part of the month was sufficient to skew December's regional departures to +2.9 degF (+5.2 degC).

The cold airmass of December opened up 2004 with arctic air that further dropped regional temperatures. Snow remained on the ground for several days in Portland and Seattle, and an ice storm plagued Portland. The pattern shifted about mid-January through its end. This change brought warmer and wetter weather, with several daily precipitation records: 1.76 inches (45mm) at Olympia, 2.59 inches (65mm) at Astoria, and 1.63 inches (41mm) at Seattle. Overall precipitation was 106 percent of normal at Columbia above Grand Coulee, 104 percent of normal at the Snake River above Ice Harbor, and 101 percent of normal at Columbia above The Dalles. January's regional temperature departures were –0.1 degF (-0.2 degC), but were not indicative of the mean swing from –4.9 degF (-8.8 degC) to +5.3 degF (+9.5 degC), brought about by the weather pattern change. The cold air of January settled in deeply over southern Idaho through to the Great Basin, and resulted in much below normal temperatures for February, thanks to strong temperature inversions. High pressure, that caused these inversions, resulted in below normal precipitation for the southern and Canadian basins in February. Most of the rain and snow fell about mid month, due to a series of cold fronts in a westerly flow targeted over mainly the central regions, containing the

Clearwater, Lower Granite, and Lower Snake districts. The seasonal accumulation of snow in the Columbia Basin is shown in Chart 1.

The fronts brought the monthly precipitation to only 54 percent of normal at the Columbia above Grand Coulee, 95 percent of normal at the Snake River above Ice Harbor, and 72 percent of normal at Columbia above The Dalles. Temperature departures were -1.0 degF (-1.8 degC), with mean departures ranging from –7.5 degF (-13.5degC) to +4.5 degF (+8.1degC). The higher sun angle of late February through early March easily broke the temperature inversions, and combined with the development of a high-pressure area in the upper air, resulted in warmer-than-normal temperatures for March. The upper level high was effective in detouring and/or weakening fronts as they moved inland. March precipitation was therefore below average, registering 83 percent of normal at Columbia above Grand Coulee, 40 percent of normal at the Snake River above Ice Harbor, and 94 percent of normal at Columbia above The Dalles. The monthly, regional temperature departure reflected the upper air pattern: +4.0 degF (+7.2 degC), with record high temperatures at several locations. Some daily readings were all-time March records, such as 78 degF (26degC) at Missoula on the 30th. At the same time that the high developed over a large part of the western U.S., a very strong low developed east of the Rockies. Although this pattern broke somewhat in April, and more so in May, it returned toward summer, and held for most of that season. In April a few strong fronts dented the upper high, and precipitation crept close to normal.

April precipitation was 77 percent of normal at Columbia above Grand Coulee, 70 percent of normal at the Snake River above Ice Harbor, and 72 percent of normal at Columbia above The Dalles. The effective precipitation occurred mainly in mid-month, with drier conditions prevailing at it’s start and close. Regional temperatures departed +2.9 degF (+5.2degC), with another set of daily record readings, notably 75 degF (24degC) on the 30th at Astoria. Wetter, yet continued mild, weather came in May, as at least two upper level low pressure troughs moved through the region, further caving in the once-established upper high. Warmer-than-normal offshore water temperatures likely helped keep nighttime minima above normal. This, coupled with the onshore flow brought about by these transient upper troughs, resulted in quite a bit of cloud cover and precipitation. May was a boost to streamflows, with its precipitation at 124 percent of normal at Columbia above Grand Coulee, 145 percent of normal at the Snake River above Ice Harbor, and 140 percent of normal at Columbia above The Dalles. A daily rainfall record was set at Spokane on the 21st, with 2.19 inches (56mm).

The regional temperature departure was close to normal, at +0.3 degF (+0.5 degC), with some chilly readings in western Montana helping to skew the values. The upper air high that weakened from its March strength, regained footing in June, although not of the caliber from June of 2003. Nonetheless, the strengthening of the ridge, and the locking-in of low pressure, once again, east of the Rockies signaled a turn toward warmer and drier weather, especially mid to late in the month. As such, June precipitation was 79 percent of normal at Columbia above Grand Coulee, 97 percent of normal at the Snake River above Ice Harbor, and 92 percent of normal at Columbia above The Dalles. A strong and wet thunderstorm pattern resulted in these higher values for the Snake River above Ice Harbor. Some studies have shown that with warmer-than-normal water temperatures in the eastern Gulf of Alaska, the Pacific Northwest often experiences an above normal warm-season of severe weather, containing strong storms. These patterns are often characterized by above normal temperatures, in part again held up due to warmer minimum temperatures. For June, regional temperatures departed +1.5 degF (+2.7 degC). Summer began warm, extending through its first full month of July, with only a temporary low-pressure trough bringing another round of strong and wet thunderstorms to the same regions as that in June.

As a result, July precipitation was greatest, relative to normal, above Ice Harbor at the Snake River, with 96 percent of normal. At Columbia above Grand Coulee, it totaled 77 percent of normal, and 76 percent of normal at Columbia above The Dalles. Along with the frequent thunderstorms and severe weather, the biggest story of July was the warmth, resulting in record high temperatures. These included readings for the 23rd: 96 degF (36 degC) at Astoria and 103 degF (39 degC) at Portland. Overall, the Basin's temperatures departed +3.0 degF (+5.4 degC), with continued above normal overnight readings, and a general increase in relative humidity readings. The pattern remained largely unchanged through much of August, until the onset of the first few Atlantic hurricanes, and an active west Pacific typhoon cycle set the stage for a wet turnaround later in August.

A burst of precipitation occurred between the 20th and 28th of August, elevating totals to above normal, and causing rises in streamflows. In a normally very dry month in most sectors, the resultant breakdown was impressive: 195 percent of normal at Columbia above Grand Coulee, 192 percent of normal at Snake above Ice Harbor, and 204 percent of normal at Columbia above The Dalles. August had many record precipitation events, within a nine-day period. Some of these included 1.07 inches (27mm) at Missoula, and 0.51 inches (13 mm) at Yakima. August regional temperatures departed +2.1 degF (+3.8 degC), but cooler conditions were on the way, as this shift in the weather pattern led to the development of an upper level low-pressure trough close to the Pacific Northwest to open September. In September, temperatures departed roughly –2.0 degF (-3.6 degC), and regional precipitation ran near to slightly above normal, especially after storms in the first five days of the month. Seasonal precipitation for the Columbia Basin is shown in Chart 2. Monthly-accumulated precipitation for sub-basins is shown in Chart 3. Chart 4 shows monthly temperature departures across the basin.

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 August 2003 through 30 September 2004 are shown on Charts 5 through 7. Chart 8 shows Libby hydrographs. Kootenay Lake regulation is shown in Chart 9. This chart shows the unregulated elevation of the lake as computed using the lowering formula. Observed flow with the computed unregulated flow hydrographs for the same 14-month period for Columbia River at Birchbank, Grand Coulee and The Dalles are shown on Charts 10, 11, and 12, respectively. Chart 13 is a hydrograph of observed and unregulated flows at The Dalles during the April through July 2004 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 1 percent below last year's below average streamflows. May had the highest unregulated flow during the spring runoff, at 78 percent of average. The August 2003 through July 2004 runoff for The Dalles was 132.2 km^3 (107.15 Maf), 78 percent of the 1971-2000 average. The peak-unregulated discharge for the Columbia

River at The Dalles was 11,536 m^3/s (407,368 cfs) on 31 May 2004. The 2003-04 average monthly-unregulated streamflows and their percentage of the 1971-2000 average monthly flows are shown in the following tables (metric and English) for the Columbia River at Grand Coulee and The Dalles. These flows have been adjusted to exclude the effects of regulation provided by storage reservoirs.

Columbia River Flow

	Columbia River at Grand Coulee			Columbia River at The Dalles		
Time	Natural Flow		Percent of	Natural Flow		Percent of
Period	m3/s	cfs	Average	m3/s	cfs	Average
Aug. 2003	2,044	72,190	69	2,603	91,919	67
Sept. 2003	1,192	42,086	68	1,750	61,785	66
Oct. 2003	1,856	65,543	146	2,712	95,764	116
Nov. 2003	1,171	41,347	84	2,211	78,081	83
Dec. 2003	895	31,606	73	2,014	71,131	72
Jan. 2004	856	30,222	72	2,046	72,255	70
Feb. 2004	886	31,278	68	2,456	86,729	74
Mar. 2004	1,429	50,456	81	3,680	129,961	83
Apr. 2004	3,929	138,754	113	6,562	231,734	97
May.2004	5,896	208,227	78	9,602	339,101	78
June 2004	6,577	232,256	75	9,185	324,356	71
July 2004	4,023	142,066	74	5,109	180,417	70
Operating Year	2,563	90,503	83	4,161	146,936	79

Seasonal Runoff Forecasts and Volumes

Inflows for 2004 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 km^3	Volume in kaf	Percentage of 1971-2000 Average
Libby Reservoir Inflow	5.77	4,676	75
Duncan Reservoir Inflow	2.29	1,854	91
Mica Reservoir Inflow	12.50	10,140	90
Arrow Reservoir Inflow	25.10	20,352	89
Columbia River at Birchbank	42.72	34,646	86
Grand Coulee Reservoir Inflow	60.84	49,338	82
Snake River at Lower Granite	19.86	16,107	70

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2003 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, Libby projects and The Dalles. Also shown in Table 1 and Table 1M are the actual runoff 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 River Forecast Center, in cooperation with the USACE, National Resource Conservation Service, Bureau of Reclamation, and B.C. Hydro. The 1 April 2004 forecast of January through July runoff for the Columbia River above The Dalles was 90.5 km^3 (73.4 Maf) and the actual observed runoff was 90.0 km^3 (73.0 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 km^3 (Maf). The average January-July runoff for the 1971-2000 period was 132.35 km^3 (107.3 Maf).

Historical January-July Volume Runoff Volume Forecasts at The Dalles, Oregon

	Maf							km³						
Year	Jan	Feb	Mar	Apr	May	Jun	Actual	Jan	Feb	Mar	Apr	May	Jun	Actual
1970	82.5	99.5	93.4	94.3	95.1	n/a	95.7	101.8	122.7	115.2	116.3	117.3	n/a	118
1971	110.9	129.5	126	134	133	135	137.5	136.8	159.7	155.4	165.3	164.1	166.5	169.6
1972	110.1	128	138.7	146.1	146	146	151.7	135.8	157.9	171.1	180.2	180.1	180.1	187.1
1973	93.1	90.5	84.7	83	80.4	78.7	71.2	114.8	111.6	104.5	102.4	99.2	97.1	87.8
1974	123	140	146	149	147	147	156.3	151.7	172.7	180.1	183.8	181.3	181.3	192.8
1975	96.1	106.2	114.7	116.7	115.2	113	112.4	118.5	131	141.5	143.9	142.1	139.4	138.6
1976	113	116	121	124	124	124	122.8	139.4	143.1	149.3	153	153	153	151.5
1977	75.7	62.2	55.9	58.1	53.8	57.4	53.8	93.4	76.7	69	71.7	66.4	70.8	66.4
1978	120	114	108	101	104	105	105.6	148	140.6	133.2	124.6	128.3	129.5	130.3
1979	88	78.6	93	87.3	89.7	89.7	83.1	108.5	97	114.7	107.7	110.6	110.6	102.5
1980	88.9	88.9	88.9	89.7	90.6	97.7	95.8	109.7	109.7	109.7	110.6	111.8	120.5	118.2
1981	106	84.5	84.5	81.9	83.2	95.9	103.4	130.7	104.5	104.2	101.1	102.6	118.3	127.5
1982	110	120	126	130	131	128	129.9	135.7	148	155.4	160.4	161.6	157.9	160.2
1983	110	108	113	121	121	119	118.7	135.7	133.2	139.4	149.3	149.3	146.8	146.4
1984	113	103	97.6	102	107	114	119.1	139.4	127	120.4	125.8	132	140.6	146.9
1985	131	109	105	98.6	98.6	100	87.7	161.6	134.5	129.5	121.6	121.6	123.3	108.2
1986	96.8	93.3	103	106	108	108	108.3	119.4	115.1	127	130.7	133.2	133.2	133.6
1987	88.9	81.9	78	80	76.7	75.8	76.5	109.7	101	96.2	98.7	94.6	93.5	94.4
1988	79.2	74.8	72.7	74	76.1	75	73.7	97.7	92.3	89.7	91.3	93.9	92.5	90.9
1989	101	102	94.2	99.5	98.6	96.9	90.6	124.6	125.8	116.2	122.7	121.6	119.5	111.8
1990	86.5	101	104	96	96	99.5	99.7	106.7	124.6	128.3	118.4	118.4	122.7	123
1991	116	110	107	106	106	104	107.1	143.1	135.7	132	130.7	130.7	128.3	132.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4	114.2	109.9	103	87.8	87.8	83.6	86.8
1993	92.6	86.5	77.3	76.6	71.9	86.1	88	114.2	106.1	95.3	94.5	101	106.2	108.5
1994	79.7	76.3	78.1	73.2	75.5	76.4	75	98.3	94.1	96.3	90.3	93.1	94.2	92.5
1995	101.1	99.6	94.3	99.6	99.6	97.9	104	124.6	122.9	116.3	122.9	122.9	120.8	128.3
1996	116	122	130	126	134	141	139.3	143.1	150.5	160.4	155.4	165.3	173.9	171.8
1997	138	145	142	149	153	159	159	170.2	178.9	175.2	183.8	188.7	196.1	196.1
1998	86.4	95.2	91.7	90.8	89.1	101	104	106.6	117.4	113.1	112	109.9	124.6	128.3
1999	116	1193	130	128	124	123	124.1	143.1	146.8	160.4	157.9	153	151.7	153.1
2000	105	106	105	105	105	102	98	129.5	130.7	129.5	129.5	129.5	125.8	120.9
2001	80.4	66.4	58.6	56.1	56.5	55.5	58.2	99.2	81.9	72.3	69.2	69.7	68.5	71.8
2002	100	102	97.3	96.4	98.2	100	103.8	123.4	125.8	120	118.9	121.1	123.4	128
2003	80.5	75.6	74.9	85.3	90.2	89.3	87.7	99.3	93.3	92.4	105.2	111.3	110.1	108.2
2004	103.0	100.0	92.9	84.2	79.5	85.1	83.0	127.7	123.4	114.6	103.9	98.1	105.0	102.4

V RESERVOIR OPERATION

General

The 2003-2004 operating year began with Canadian storage at 88.7% full. Libby reservoir (Lake Koocanusa) was not full on 1 August 2003 as the dam was releasing water to meet the objectives for flow augmentation for listed salmon species in the U.S.

The September through November period is typically a time of base flow at the reservoirs, but a late October rain event caused Canadian reservoirs and Libby reservoir to fill slightly. The January water supply forecast at the Canadian basins was slightly below average and remained below average through the spring. Because of less than average water supply the Canadian storage projects operated in proportional draft through early spring and did not refill at the end of the operating year. Canadian storage ended the year at 88.5% full, near where it started.

Two CRTOC operating agreements enhanced fishery operations at Arrow. Libby Dam operated to meet the needs of both U.S. Fish and Wildlife Service 2000 Biological Opinion, and the National Marine Fisheries Service (now called NOAA Fisheries) 2000 Biological Opinion. Libby operated in accordance with Appendix B (The Libby Operating Plan) of the Libby Coordination Agreement (LCA).

Canadian Treaty Storage Operation

At the beginning of the 2003-2004 operating year, 31 July 2003, actual Canadian Treaty storage (Canadian storage) was at 17.0 km^3 (13.8 Maf) or 88.7 percent full. Canadian storage was drafted between August 2003 and March 2004, reaching a minimum of 3.6 km^3 (2.9 Maf) on 31 March 2004. Similar to the year before, Canadian storage did not refill fully during the operating year, reaching 16.9 km^3 (13.7 Maf) or 88.5 percent full on 31 July 2004.

As specified in the Detailed Operating Plan (DOP), the release of Canadian storage is made effective at the Canadian-U.S. border. Accordingly, releases from individual Canadian projects can vary from the release required by the DOP Treaty Storage Regulation (TSR) plus supplemental operating agreements so long as this variance does not impact the ability of the Canadian system to deliver the sum of CRT 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 CRT release required at the Canadian-U.S. border. The terms under/overrun are used in the description of Mica Reservoir operations below.

Mica Reservoir

As shown in Chart 5, Mica (Kinbasket) reservoir was at elevation 742.83 m (2437.1 feet) on 31 July 2003. After temporarily cresting at an elevation of 744.32 m (2442.0 feet) on 23 August 2003, the reservoir established a slightly higher peak elevation of 744.57 m (2442.8 feet) on 29 October 2003, 9.81 m (32.2 feet) below full pool. The higher elevation in October was the result of high inflows due to a rainfall event, setting daily and monthly rainfall records at some stations. As inflows declined following an early season cold winter outbreak in November, the reservoir drafted steadily, reaching 734.53 m (2,409.9 feet) on 31 December 2003. The reservoir continued to draft January through early April, reaching a minimum elevation of 718.47 m (2,357.2 feet) on 12 April 2004, about 8 m (26 feet) below the average elevation for this date. The refill level of the Mica reservoir during 2004 was impacted by a low initial level as well as below normal seasonal inflows. As a result, reservoir refill level was much below normal, reaching a maximum elevation of 746.9 m (2450.5 feet) on 30 September 2004, 7.47 m (24.5 feet) below full pool.

Inflow into Mica reservoir was near normal over the period August 2003 to December 2003. Over this same period, Mica outflow varied from a monthly average low of 256 m^3/s (9000 cfs) in October to a monthly average high of 933 m^3/s (32,950 cfs) in December. Inflow into Mica reservoir was 88 percent of normal over the period January 2004 to July 2004. Outflow over this same period varied from a monthly average high of 1012 m^3/s (35,700 cfs) in January to a monthly average low of 32 m^3/s (1,100 cfs) in June.

The Mica project had an underrun of 872.9 cubic hectometers (hm^3) (356.8 thousand second-foot-days (ksfd)) on 31 July 2003. The underrun was gradually reduced to a minimum of 477.1 hm^3 (195.4 ksfd) on 11 September 2003 before increasing again to a maximum of 2709 hm^3 (1107.3 ksfd) on 7 July 2004. The Mica underrun as of 31 July 2004 was 1936 hm^3 (791.3 ksfd).

The B.C. Hydro Non-Treaty Storage Agreement (NTSA) active storage account was at 1390.0 hm^3 (568.0 ksfd) on 31 July 2003 and 814.6 hm^3 (333 ksfd) on 30 June 2004. The corresponding U.S. NTSA account was at 1311.8 hm^3 (536.2 ksfd) and 13.9 hm^3 (5.7 ksfd), respectively. The NTSA Agreement terminated, with respect to release rights, on 30 June 2004. Under the NTSA Extended Provisions, active storage accounts must be refilled prior to 30 June 2011.

Revelstoke Reservoir

During the 2003-2004 operating year, the Revelstoke project was operated as a run-of-river plant with the reservoir level maintained generally within 0.91 m (3.0 feet) of its normal full pool elevation of 573.02 m (1,880.0 feet). During the spring freshet, March through July, the reservoir operated as low as elevation 571.65 m (1,875.5 feet), or 1.37 m (4.5 feet) below full pool, to provide additional operational space to control high local inflows. Changes in Revelstoke storage levels did not affect CRT storage operations.

Arrow Reservoir

As shown in Chart 6, the Arrow reservoir was at elevation 438.25 m (1437.8 feet) on 31 July 2003. The coordinated hydro system was on proportional draft from August 2003 through January 2004, which contributed to the Arrow Reservoir being drafted much earlier than normal. By 31 December 2003, the reservoir was drafted to 427.00 m (1400.9 feet), about 5 m (16 feet) below the average elevation for this date. The reservoir reached its minimum level of the year at elevation 425.23 m (1395.1 feet) on 31 March 2004. The reservoir refilled from April through July, reaching a maximum level of 436.24 m (1431.3 feet) on 12 August 2004, 3.9 m (12.7 feet) below full pool.

Local inflow into Arrow reservoir was 96 percent of normal over the period August 2003 to December 2003. Proportional draft of the coordinated hydro system contributed to Arrow outflows being approximately 12 percent higher than the historical average for this corresponding period. Arrow outflow varied from a monthly average low of 1175 m^3/s (41,500 cfs) in October to a monthly average high of 1679 m^3/s (59,300 cfs) in December. Daily outflows in December reached a peak of 2039 m^3/s (72,000 cfs) on 19 December before ramping down to 915 m^3/s (32,300 cfs) by the end of the month, in preparation for the start of whitefish spawning. Local inflow into Arrow reservoir was 93 percent of normal over the period January 2004 to July 2004. Outflow over this same period varied from a monthly average high of 1161 m^3/s (41,000 cfs) in January to a monthly average low of 572 m^3/s (20,200 cfs) in April.

Arrow Reservoir operation was modified during the operating year under two Operating Committee Agreements. These agreements helped to enhance the success of whitefish and rainbow trout spawning and emergence downstream of the Arrow project in British Columbia and to provide additional power and non-power benefits in the U.S. From 1 January 2004 to 19 January 2004, Arrow outflow was held near 991.1 m^3/s (35,000 cfs) to maintain low river levels during the whitefish peak spawning period. This operation reduced the number of eggs being dewatered during the incubation period in February and March 2004. Arrow outflow, from February through March 2004, was held above 736 m^3/s (26,000 cfs) to help protect deposited eggs. During April and May 2004, Arrow outflows were maintained at approximately 566 m^3/s (20,000 cfs) to ensure successful rainbow trout spawning below Arrow, at water levels that could be maintained until hatch.

Keenleyside Dam with the Columbia Generating Station operational.

Duncan Reservoir

As shown in Chart 7, the Duncan reservoir substantially refilled during 2003, reaching 576.44 m (1891.2 feet), 0.24 m (0.8 feet) below full pool on 1 August 2003. The reservoir was maintained within about 0.3 m (1.0 feet) below full pool through August as a flood buffer and to support recreation on the reservoir. The reservoir recorded a maximum elevation of 576.46 m (1891.3 feet), 0.22 m (0.7 feet) below full pool on 19 August 2003.

The project passed inflows until 22 August 2003 when the reservoir started to draft. Discharges were increased to 280 m^3/s (10,000 cfs) through the first half of September to augment inflow into Kootenay Lake before reducing to 170 m^3/s (6,000 cfs) from mid-September through October. A storm on 21 October 2003 resulted in inflows of 667 m^3/s (23,500 cfs) into Duncan Reservoir (the 5th highest inflow on record). Discharges were reduced to 3 m^3/s to minimize downstream flooding and the reservoir level increased 1.4 m (4.5 feet) over a period of a few days. From 01-28 November 2003, discharges were reduced to 57 m^3/s (2,000 cfs) to study whitefish spawning in the lower Duncan River. From December through February, discharges ranged from 62 m^3/s to 227 m^3/s (2,200 to 8,000 cfs) to assist with Arrow whitefish flows and to target elevation of about 551.1 m (1808 feet) by 1 March 2004, to ensure sufficient storage for maintaining minimum flows for fish until spring. Discharges in March and April 2004 ranged from 59 m^3/s to 119 m^3/s (2,100 to 4,200 cfs) to provide a minimum flow of 74 m^3/s (2,600 cfs) on the Duncan River below the confluence of the Lardeau River and to empty the reservoir prior to the freshet.

Reservoir discharge was reduced to the minimum of 3 m^3/s (100 cfs) on 11 May 2004 to initiate refill. The observed season water supply at Duncan for the February through September period was 86 percent of normal. The reservoir refilled later than normal during 2004, reaching 574.05 m (1883.4 feet), 2.6 m (8.6 feet) below full pool on 1 August 2004. The reservoir reached a maximum elevation of 576.45 m, (1891.2 feet) on 16 August 2004, 0.23 (0.8 feet) below full pool. Through the balance of August, the reservoir was maintained within about 0.3 m (1.0 feet) below full pool to provide a flood buffer and to support recreation on the reservoir.

In September 2004, Duncan discharge was increased to between 227 m^3/s and 283 m^3/s (8,000 cfs and 10,000 cfs) to draft the reservoir prior to the start of kokanee and whitefish spawning. Discharges were reduced to 74 m^3/s (2,600 cfs) in October to facilitate spawning at lower flows to limit the risk of over-winter dewatering of redds.

Libby Reservoir

As shown in Chart 8, Lake Koocanusa began August 2003 at elevation 736.1 m (2453.8 feet), 1.56 m (5.2 feet) from full. Outflow in August was 509.7 m^3/s (18 kcfs) during most of the month, but was reduced somewhat near the end of the month. The operating strategy was to draft the reservoir to elevation 743.4 m (2439 feet) by 31 August to meet the objectives of NOAA Fisheries 2000 Biological Opinion. Inflow averaged 169.9 m^3/s (6 kcfs) for the month of August and outflow was maintained at 509.7 m^3/s (18 kcfs) through 21 August then ramped down to 396.4 m^3/s (14 kcfs). The project reached elevation 743.3 m (2438.8 feet) on 31 August. Project outflow ramped down from 396.4 m^3/s (14 kcfs) on 1 September, to 198.2 m^3/s (7 kcfs) on 7 September 2003. Outflow was held at 198.2 m^3/s (7 kcfs) for 18 hours before it was increased to 311.5 m^3/s (11 kcfs) in response to a request from the City of Bonners Ferry. Due to a forest fire in the Myrtle Creek drainage basin, the City of Bonners Ferry's primary water supply source, the water treatment plant needed to draw from the emergency line located in the Kootenai River. Increased Libby outflow allowed the pumps to function without cavitating, to meet the one million gallon per day demand.

Lake Koocanusa began September near elevation 743.2 m (2438.4 feet). Inflow averaged 121.8 m^3/s (4.3 kcfs). Project outflow ramped down from 311.5 m^3/s (11 kcfs) on 10 September 2004, to 198.2 m^3/s (7 kcfs) on 13 September 2004 after the City installed their back-up pump. The project reached elevation 741.8 m (2433.8 feet) by the end of September. Inflow averaged 178.4 m^3/s (6.3 kcfs) for the month of October, with peak inflow on 23 September of 481.4 m^3/s (17 kcfs) due to a heavy precipitation event. Outflow averaged 127.4 m^3/s (4.5 kcfs) and the project ended October at elevation 742.6 m (2436.5 feet).

Lake Koocanusa began November near elevation 742.5 m (2436 feet). From 2 October through 15 November, Libby Dam released 130.3 m^3/s (4.6 kcfs), which was running one unit at maximum efficiency. On 16 November, the project increased to 566.3 m^3/s (20 kcfs) to release some water from the project in order to accommodate lower burbot flows the last two weeks in December. Outflows were ramped down over the Thanksgiving weekend and then increased again to 566.3 m^3/s (20 kcfs) during the period 1-15 December. Outflows were again ramped down, and 283.2 m^3/s (10 kcfs) outflow was achieved 20 December – 4 January. The elevation of Lake Koocanusa was 734.8 m (2410.91 feet) on 31 December. Between 6 January and 12 January, outflows were 339.8 m^3/s (12 kcfs). The Corps December final volume forecast was 108%. Lake Koocanusa began January at its required flood control elevation of 734.9 m (2411 feet) and drafted 2.2 m (7.1 feet) over the first two weeks as releases averaged 300.2 m^3/s (10.6 kcfs). The Corps VARQ January final volume forecast for Libby was 91.4% of normal. This raised the end of January flood control target elevation from 731.2 m (2399 feet) to 738.4 m (2422.5 feet). In response to this forecast change, releases during the second two weeks were reduced to 113.3 m^3/s (4 kcfs). The ramp down started 12 January. The pool drafted another 0.4 m (1.3 feet) to reach elevation 732.3 m (2402.6 feet) by 31 January.

The January final forecast of 5.7 MAF required a 31 January VARQ flood control elevation of 738.4 m (2422.5 feet). Releases remained at 113.3 m^3/s (4.0 kcfs) throughout February, and the pool reached elevation 731.5 m (2399.8 feet) by 29 February. The February final forecast of 5.6 MAF required a 29 February flood control elevation of 741.2 m (2431.6 feet).

Lake Koocanusa began March at 731.5 m (2399.9 feet) and drafted 0.4 m (1.3 feet) over the month with releases held at minimum flow, or 113.3 m^3/s (4.0 kcfs) throughout the month. April continued to be dry, so the project continued to release 113.3 m^3/s (4.0 kcfs) throughout April. The March final forecast for the period of April thru August of 5.36 MAF required a 30 April flood control elevation of 744.7 m (2443.4 feet) while the April final forecast of 5.31 MAF required an 30 April flood control of elevation of 745 m (2444.3 feet). Low inflow to the project required the minimum outflow be maintained, and the end of April elevation was 734.6 m (2410.1 feet). The May final forecast continued the downward trend and was 4.935 KAF, or 79% of normal.

Lake Koocanusa began May at 734.6 m (2410.1 feet) and filled 6.5 m (21.2 feet) over the month with releases held at minimum flow, or 113.3 m^3/s (4.0 kcfs) through 28 May and ramping up to 368.1 m^3/s (13 kcfs) by 31 May. Evidence of sturgeon spawning on 29 May caused the project to increase discharge to 368.1 m^3/s (13 kcfs). The sturgeon pulse required increasing flows from Libby Dam to maintain a high velocity in the spawning area downstream of the project. Flows were ramped to 396.4 m^3/s (14 kcfs) on 6 June, 424.8 m^3/s (15 kcfs) on 13 June, and 453.1 m^3/s (16 kcfs) on June 20 as outlined in a System Operation Request (SOR) from the U.S. Fish and Wildlife Service. The pulse ended on 27 June, at which time flows were ramped down to 354 m^3/s (12.5 kcfs), which was forecast to draft Lake Koocanusa to elevation 743.4 m (2439 feet) by 31 August with an April-Aug inflow volume of 4.44 MAF. Lake Koocanusa reached elevation 745.6 m (2446.1 feet) on 30 June. Inflow in July remained consistently higher than outflow (532.4 m^3/s (18.8 kcfs) vs. 354 m^3/s (12.5 kcfs)), which allowed Lake Koocanusa to fill another 1.2 m (4 feet) from 1-14 July for a midnight elevation of 746.8 m (2450.1 feet) on 14 July. Lake Koocanusa finished the month of July at elevation 746.5 m (2449.2 feet).

Lake Koocanusa continued through the month of August 2004 with a steady outflow of 354 m^3/s (12.5 kcfs). Elevation at the end of August was 745.2 m (2445 feet).

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay was at elevation 531.61 m (1744.1 feet) on 31 July 2003. By 18 November 2003, Kootenay Lake was drafted to 531.05 m (1742.3 feet), 0.9 m (3.0 feet) below the maximum IJC level. The lake levels remained well below the IJC level throughout the fall in order to minimize spill at the Brilliant project later in the year and to meet system requirements. The lake refilled in December due to increased discharges from Libby.

Kootenay Lake was drafted during January to March to remain below the maximum IJC level and to meet generation requirements. On 18 March 2004, Kootenay Lake was at its minimum elevation for the year of 530.02 m (1738.9 feet).

The Kootenay Lake Board of Control declared the commencement of the spring rise for the regulation of Kootenay Lake on 7 April 2004. Following the declaration of spring freshet, Kootenay Lake was operated in accordance to the IJC lowering formula. During April, as inflow increased beyond the maximum outflow capacity as controlled at Grohman Narrows, the lake elevation rose to 530.76 m (1741.3 feet) by the end of the month.

Kootenay Lake discharge was increased in accordance with the IJC order for Kootenay Lake. Inflow peaked at 1654 m^3/s (58,400 cfs) on 7 June 2004. Discharge from the lake peaked at 1138 m^3/s (40,000 cfs) on 2 July 2004. Kootenay Lake reached a peak elevation of 532.21 m (1746.1 feet) on 16 June 2004.

As runoff receded during July, Kootenay Lake levels started to drop and discharges were adjusted to control reservoir levels slightly below the IJC limits. The level at the Nelson gauge drafted below the trigger elevation of 531.36 m (1743.32 feet) on 14 July 2004. Discharges were adjusted to control the Nelson gauge slightly below that level until the end of August. Kootenay Lake was at elevation 531.48 m (1743.7 feet) on 31August 2004.

Storage Transfer Agreements

A storage transfer agreement to store water in Libby and release it from Canadian storage was not reached during the summer of 2003. Hydrologic conditions were not favorable in Canada, and the CRTOC did not pursue an agreement.

During the summer of 2004, a tentative storage transfer agreement was reached but not implemented. Libby reservoir was not expected to refill after the sturgeon operation ended in June. Executives in the U.S. reached an agreement in late July where Libby released steady 354 m^3/s (12.5 kcfs) through the July-August period. The intent was to have Lake Koocanusa end August at elevation 743.4 m (2439 feet), but a late August rain event filled the reservoir above the target elevation. The executive agreement superceded a CRTOC storage transfer agreement.

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 CRT and operating plans and agreements described in Section III. Consistent with all DOP's prepared since the installation of generation at Mica, the 2003-2004 and 2004-2005 DOP's were designed to achieve optimum power generation at-site in Canada and downstream in Canada and the U.S., in accordance with paragraph 7 of Annex A of the CRT.

Power operations are developed through Critical Rule Curves (CRC), Assured Refill Curves (ARC) and Variable Refill Curves (VRC). The VRCs are dependent upon the water supply in any given water year and the VRC is updated each month with the development of a new water supply forecast. The monthly VRC calculation for Mica, Arrow and Duncan are shown in Tables 2 – 4 and 2M – 4M. The calculation for Libby VRCs is shown in Tables 5 and 5M. Libby VRCs are used in preparation of the Treaty Storage Regulation (TSR).

During the period covered by this report, Libby power operations in the TSRs were developed in accordance with the CRT and the 2001 CRT FCOP (updated in May 2003). During the fall period from September through December, Libby operated for power purposes according to the PNCA AER. From mid-January through March 2004 the outflow from Libby Dam was at minimum flow that enhanced Burbot movement in the Kootenai River. As recommended by the USACE on 31 December 2002, Libby operated to VARQ (Variable flow) flood control on an interim basis in 2004, as it did in 2003. From June through August, Libby operated for storage and releases recommended for endangered white sturgeon and salmon by the 2000 U.S. Fish and Wildlife Service (USFWS) and National Marine Fisheries Service (NMFS now called NOAA Fisheries) Biological Opinions (BiOps).

Flood Control

While the 2004 water supply forecasts averaged below normal across the Columbia River Basin, the reservoir system, including the Columbia River Treaty projects were still required to draft for flood control in preparation for the spring freshet. Inflow forecasts and reservoir regulation modeling were done weekly throughout the winter and spring. Projects were operated according to the 2001 FCOP, updated May 2003. With above normal precipitation in May and warm temperatures in June, actual runoff volumes were higher than forecast at the Columbia River Treaty projects. The unregulated peak flow at The Dalles, Oregon, shown on Chart 13, was estimated at 11,536 m^3/s (407,370 cfs) on 31 May 2004 and a regulated peak flow of 8,184 m^3/s (289,000 cfs) occurred on 29 May 2004. The unregulated peak stage at Vancouver, Washington was calculated to be 4.33 m (14.2 feet) on 31 May 2004 and the highest-observed stage was 2.96 m (9.7 feet) on 31 January 2004. Flood stage at Vancouver, Washington, is 4.9 m (16 feet).

Chart 14 shows the relative filling of Arrow and Grand Coulee during the filling period and compares the regulation to guide lines, Chart 6, of the CRT FCOP. Low runoff conditions last year and slightly below normal runoff conditions this year caused Mica to be drafted very deeply for power. There were no daily operations specified for Arrow, and the projects were able to meet both fish flow and flood control objectives. In operating year

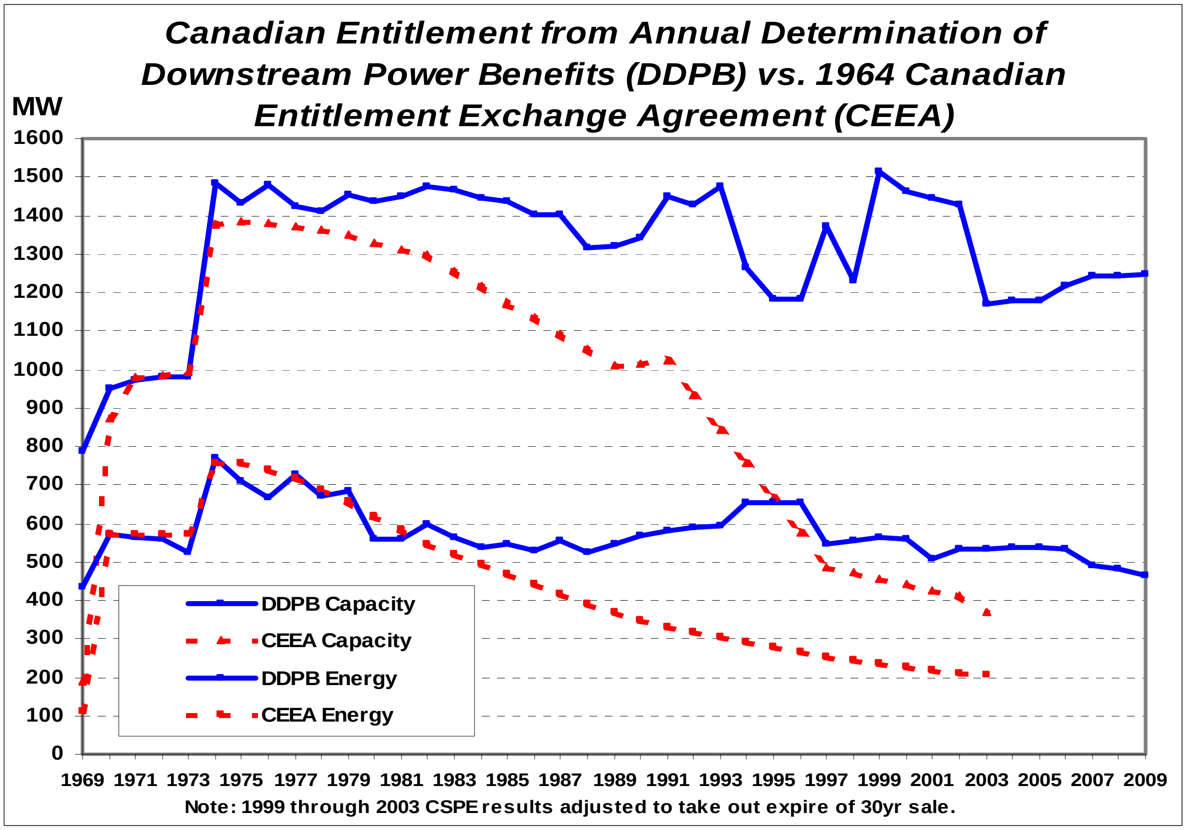
2003-2004 Mica and Arrow operated to “shifted” flood control as defined in the 2003 FCOP. In operating year 2003-2004 the shifted flood control operation was defined when the Canadian Entity requested that Mica and Arrow operate to the flood control storage allocations of 3.6 Maf maximum draft at Arrow and 4.08 Maf maximum draft at Mica. The operating committee agreed on 16 July 2003.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the CRT FCOP. Computed ICF’s at The Dalles were 9,741 m^3/s (344,000 cfs) on 1 January 2004; 9486 m^3/s (335,000 cfs) on 1 February 2004; 8750 m^3/s (309,000 cfs) on 1 March 2004; 7,136 m^3/s (252,000 cfs) on 1 April 2004; and 6,513 m^3/s (230,000 cfs) on 1 May. As mentioned earlier, the observed peak flow at The Dalles was 8,184 m^3/s (289,500 cfs) on 29 May 2004. Data for the 1 May ICF computation are given in Table 6.

Canadian Entitlement

From 1 August 2003 through 30 September 2004, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Canadian Treaty storage to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amounts returned, not including transmission losses and scheduling adjustments, are listed in Section III of this report, under the heading Canadian Entitlement. No Entitlement power was disposed directly in the U.S. during 1 August 2003 through 30 June 2004, using specific provisions of the 29 March 1999 Agreement on “Disposals of the Canadian Entitlement Within the U.S. for 4/1/98 through 9/15/2024.” However, during 1 July 2004 through 30 September 2004, the Entitlement’s owner, the Province of British Columbia, entered into a short-term disposal in the United States of up to 400 MW, scheduled to terminate on 31 October 2004, at which time that power will once again be returned to the U.S.-Canada border.

The following graph shows the historic Canadian Entitlement computation from the DDPB studies together with the amount sold under the CEPA.

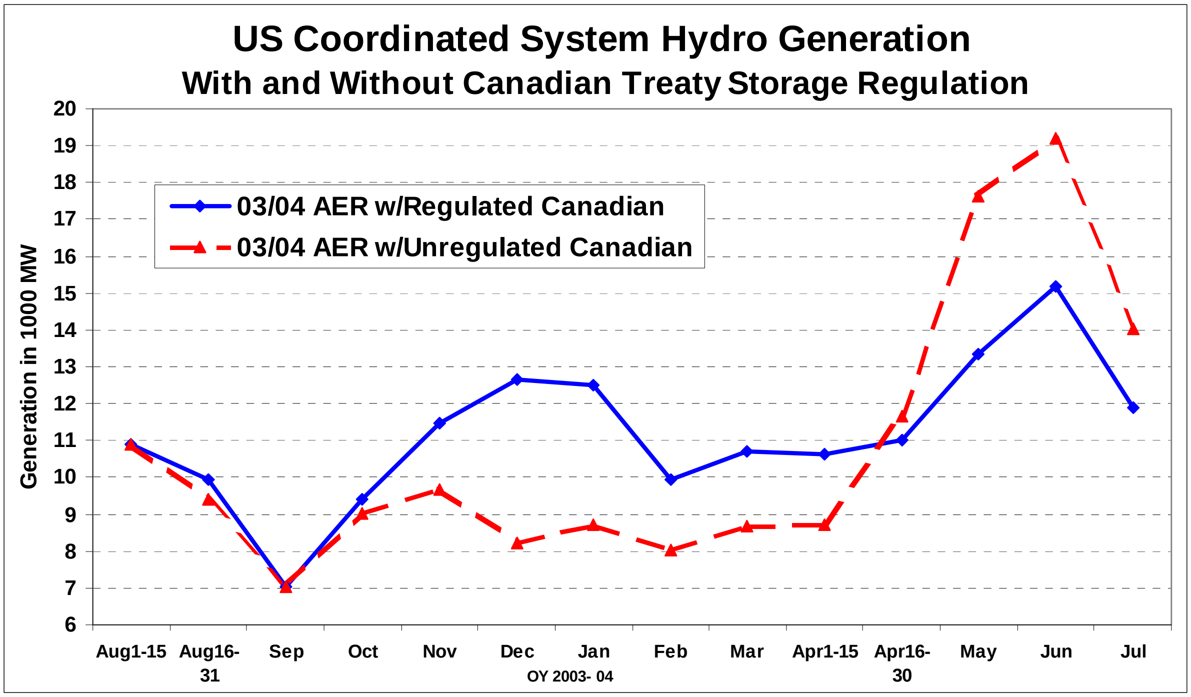


In accordance with the Canadian Entitlement Allocation Extension Agreement, dated April 1997, the U.S. Entity granted permission for the non-federal downstream U.S. parties to make use of the U.S. one-half share of the CRT downstream power benefits (U.S. Entitlement).

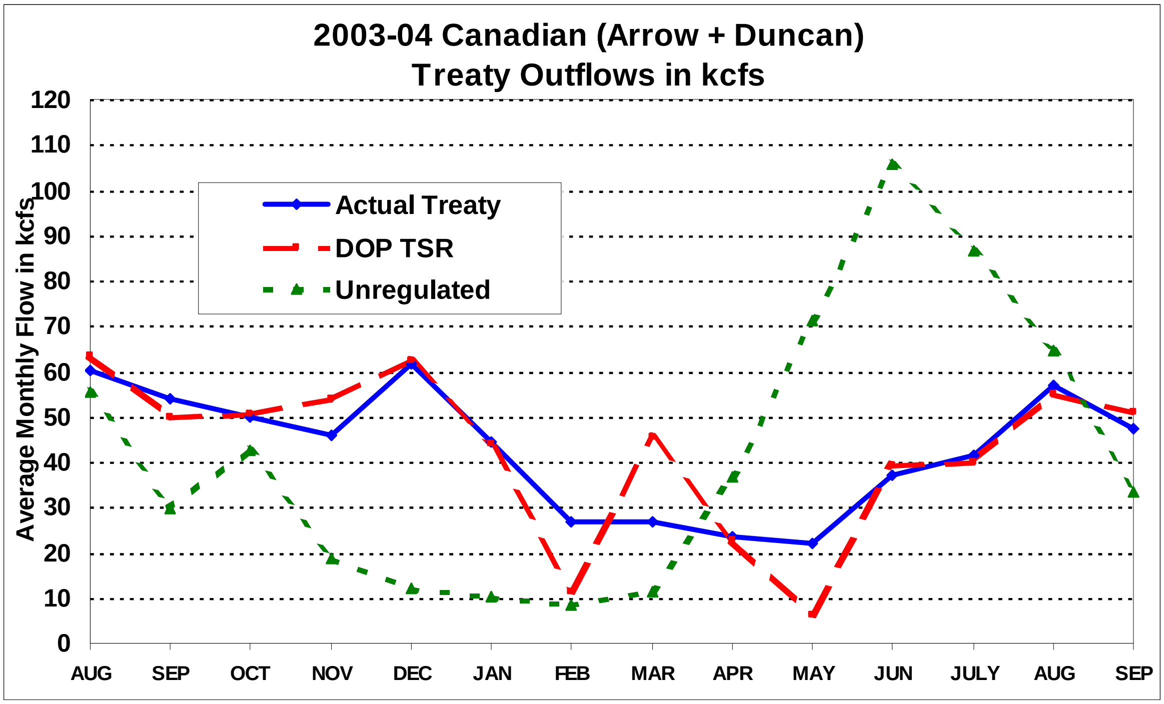
Power Generation and other Accomplishments

At the beginning of the 2003-2004 operating year, the TSR storage level for Canadian storage was only 89.6 percent full, and the actual Canadian storage was slightly below 88.7 percent full. Due to the below full starting storage contents the hydro system continued to draft proportionally below the Operating Rule Curve (ORC) throughout the operating year. During February through June the coordinated system recovered to the ORC, with the exception of Mica, which was limited by target and minimum flow requirements. The TSR again drafted below the ORC in July 2004 to maintain the firm load carrying capability of the Coordinated System. Actual Canadian storage on 31 July 2004 reached 88.5 percent full, slightly below the TSR level for Canadian storage of 89.1 percent full.

Actual U.S. power benefits from the operation of CRT storage are unknown and can only be roughly estimated. Treaty storage has such a large impact on the U.S. system operation that its absence would significantly affect operating procedures, non-power requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative. The following graph shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2003-2004 operating year, with and without the regulation of Canadian storage, based on the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER) that includes minimum flow and spill requirements for U.S. fishery objectives. The increase in average annual U.S. power generation due to the operation of Canadian storage, as measured by the PNCA AER, was 398 aMW.



Based on the authority from the 2002-2003 and 2003-2004 DOPs, the Operating Committee completed several supplemental operating agreements, described in Section III, which resulted in power and other benefits both in Canada and the U.S. Other benefits include changes to streamflows below Arrow that enhanced trout and white fish spawning and the downstream migration of salmon. The following graph shows the difference in Arrow plus Duncan average monthly-regulated outflows between the DOP TSR and the actual CRT flows due to these agreements. The unregulated streamflow is also shown for comparison purposes.



As of 30 September 2003, the sum of Canadian Treaty storage was approximately 171 hm^3 (70 ksfd) below the DOP TSR as a result of the Canadian Entity draft of that amount under terms of the LCA. Canada exercised LCA provisional draft and return through October while the U.S. utilized flexibility to provisionally draft and store under the Whitefish Agreement during the same period. Although the parties targeted a Canadian Treaty storage content of about 526 hm^3 (215 ksfd) above the DOP TSR, a large change in the TSR resulting from the extraordinarily high precipitation in October resulted in ending the month about 147 hm^3 (60 ksfd) below the DOP TSR.

In November Canadian Treaty storage continued to be operated under the Whitefish Agreement and ended the month at about 489 hm^3 (200 ksfd) above DOP TSR levels. In December, the U.S. and Canada reached agreement to shape flows from December through July to meet multiple system requirements and fishery needs. During December and early January, the Canadian Entity exercised LCA provisional draft and during the first 20 days in January, Arrow actual outflows were maintained at about 991 m^3/s (35 kcfs) for B.C. whitefish spawning.

In February and March, Arrow outflows were maintained as flat as practicable for B.C. whitefish protection while targeting a composite Canadian Treaty storage level of about 881 hm^3 (360 ksfd) above the DOP TSR under the Nonpower Uses Agreement. All LCA provisional draft was returned as required by the end of March.

In April, Arrow actual outflows were reduced to about 566 m^3/s (20 kcfs) to balance the needs of B.C. trout spawning, U.S. fisheries needs, and system load requirements, ending April with composite Treaty storage about 978 hm^3 (400 ksfd) above the DOP TSR. Arrow outflows were increased in late May to meet U.S. fishery needs and flood control requirements. The sum of Canadian Treaty storage ended June at approximately DOP TSR levels. Treaty projects remained near TSR levels until late July and August when the Canadian Entity exercised provisional draft totaling 137 hm^3 (56 ksfd) under the LCA.

In late August and September, the DOP TSR exhibited large changes due to increased observed stream flows. As a result, at the end of September composite Canadian Treaty storage was about 905 hm^3 (370 ksfd) below the level determined in the 8 October DOP TSR.

TABLES

Table 1: 2004 Unregulated Runoff Volume Forecasts

Million of Acre-feet

Most Probable 1 April through 31 August Forecast in Maf

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.03	20.9	11.0	5.71	89.0
February	2.01	22.0	11.0	6.00	88.2
March	1.90	21.1	10.5	5.73	82.5
April	2.00	21.8	10.7	5.30	73.4
May	1.97	21.4	10.7	4.94	68.4
June	1.98	21.3	10.7	4.78	74.4
Actual	1.85	20.4	10.1	4.68	73.0

Cubic Kilometers

Most Probable 1 April through 31 August Forecast in km^3

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.50	25.8	13.6	7.04	109.7
February	2.48	27.1	13.6	7.40	108.8
March	2.34	26.1	12.9	7.07	101.7
April	2.47	26.9	13.2	6.54	90.5
May	2.43	26.4	13.2	6.09	84.3
June	2.44	26.3	13.2	5.89	91.7
Actual	2.28	25.2	12.5	5.77	90.0

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

Table 2: 2004 Variable Refill Curve Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			9072.5	9090.4	8523.7	8448.7	7988.5	6355.3
PROBABLE DATE-31JULY INFLOW, KSFD	**		4574.0	4583.0	4297.3	4259.5	4027.5	3204.1
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/		3921.0	4072.6	3831.9	3815.0	3667.0	2843.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3921.0					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		2170.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1778.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2435.0					
JAN31 ORC, FT	7/		2431.3					
BASE ECC, FT	8/	2431.3						
LOWER LIMIT, FT		2401.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		3826.9	3974.8				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		2086.0	2086.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1788.3	1640.4				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2435.2	2432.0				
FEB28 ORC, FT	7/		2427.7	2427.7				
BASE ECC, FT	8/	2427.7						
LOWER LIMIT, FT		2395.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3728.8	3873.0	3732.3			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3300.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1993.0	1993.0	1997.2			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1793.4	1649.2	1794.1			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2435.3	2432.2	2435.3			
MAR31 ORC, FT	7/		2427.8	2427.8	2427.8			
BASE ECC, FT	8/	2427.8						
LOWER LIMIT, FT		2394.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		3528.9	3665.3	3533.0	3612.8		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		5000.0	5000.0	5000.0	5000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1873.0	1873.0	1873.0	1873.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1873.3	1736.9	1869.2	1789.4		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2437.0	2434.1	2436.9	2435.2		
APR30 ORC, FT	7/		2428.3	2428.3	2428.3	2428.3		
BASE ECC, FT	8/	2428.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2807.4	2915.9	2808.8	2872.7	2915.3	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		18000.0	18000.0	18000.0	18000.0	18000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1718.0	1718.0	1718.0	1718.0	1718.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2439.8	2331.3	2438.4	2374.5	2331.9	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2448.7	2446.5	2448.7	2447.4	2446.5	
MAY31 ORC, FT	7/		2444.8	2444.8	2444.8	2444.8	2444.8	
BASE ECC, FT	8/	2444.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1391.9	1445.8	1391.0	1423.0	1444.8	1407.6
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		38000.0	38000.0	38000.0	38000.0	38000.0	38000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		1178.0	1178.0	1178.0	1178.0	1178.0	1178.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3315.3	3261.4	3316.2	3284.2	3262.4	3299.6
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2466.0	2465.0	2466.0	2465.4	2465.0	2465.7
JUN30 ORC, FT	7/		2466.0	2465.0	2466.0	2465.4	2465.0	2464.9
BASE ECC, FT	8/	2466.0						
JUL 31 ORC, 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 (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 2M: 2004 Variable Refill Curve Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3		11.19	11.2	10.5	10.4	9.85	7.84	
PROBABLE DATE-31JULY INFLOW, HM^3	**		11190.8	11212.8	10513.8	10421.3	9853.7	7839.2
95% FORECAST ERROR FOR DATE, HM^3			1597.6	1248.7	1138.7	1087.5	882.0	882.0
95% CONF.DATE-31JULY INFLOW, HM^3	1/		9593.1	9964.0	9375.1	9333.8	8971.7	6957.2
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.		100.0						
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		9593.1					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		84.9					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		5309.1					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		4350.5					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		742.2					
JAN31 ORC, M	7/		741.1					
BASE ECC, M	8/	741.06						
LOWER LIMIT, M		732.04						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.		97.6	97.6					
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		9362.9	9724.8				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		84.9	84.9				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		5103.6	5103.6				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		4375.3	4013.4				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		742.3	741.3				
FEB28 ORC, M	7/		740.0	710.0				
BASE ECC, M	8/	739.96						
LOWER LIMIT, M		730.12						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.		95.1	95.1	97.4				
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		9122.9	9475.7	9131.5			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		84.9	84.9	93.5			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		4876.1	4876.1	4886.5			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		4387.7	4034.9	4389.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		742.3	741.3	742.3			
MAR31 ORC, M	7/		740.0	740.0	740.0			
BASE ECC, M	8/	739.99						
LOWER LIMIT, M	729.97							
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/	8633.8	8967.5	8643.8	8839.1			
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		141.6	141.6	141.6	141.6		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		4582.5	4582.5	4582.5	4582.5		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		4583.2	4249.5	4573.2	4378.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		742.8	741.9	742.8	742.3		
APR30 ORC, M	7/		740.2	740.2	740.2	740.2		
BASE ECC, M	8/	740.15						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		6868.6	7134.0	6872.0	7028.4	7132.6	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		509.7	509.7	509.7	509.7	509.7	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		4203.3	4203.3	4203.3	4203.3	4203.3	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		5969.2	5703.8	5965.8	5809.5	5705.2	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		746.4	745.7	746.4	746.0	745.7	
MAY31 ORC, M	7/		745.2	745.2	745.2	745.2	745.2	
BASE ECC, M	8/	745.18						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.		35.5	35.5	36.3	37.3	39.4	49.5	
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		3405.4	3537.3	3403.2	3481.5	3534.9	3443.8
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		1076.0	1076.0	1076.0	1076.0	1076.0	1076.0
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		2882.1	2882.1	2882.1	2882.1	2882.1	2882.1
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		8111.2	7979.3	8113.4	8035.1	7981.8	8072.8
VRC JUN30 RESERVOIR CONTENT, METERS	6/		751.6	751.3	751.6	751.5	751.3	751.6
JUN30 ORC, M	7/		751.6	751.3	751.6	751.5	751.3	751.3
BASE ECC, M	8/	751.64						
JUL 31 ORC, M		752.9	752.9	752.9	752.9	752.9	752.9	

** 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 (8634.54 HM^3) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 3: 2004 Variable Refill Curve Arrow Reservoir

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, KAF			18603.2	19247.9	17976.7	18005.2	16370.4	12231.8
& IN KSFD	**		9379.0	9704.0	9063.1	9077.5	8253.3	6166.8
95% FORECAST ERROR FOR DATE, IN KSFD			1233.4	987.3	825.2	715.6	501.7	501.7
95% CONF.DATE-31JULY INFLOW, KSFD	1/		8145.6	8716.7	8237.9	8362.0	7751.6	5665.0
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		8145.6					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		3956.0					
UPSTREAM DISCHARGE, KSFD	4/		1922.6					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1312.6					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1405.8					
JAN31 ORC, FT	7/		1405.8					
BASE ECC, FT	8/	1409.5						
LOWER LIMIT, FT		1384.4						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		7941.9	8498.8				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		3816.0	3816.0				
UPSTREAM DISCHARGE, KSFD	4/		2089.9	2089.9				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1543.6	986.7				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1410.1	1399.5				
FEB28 ORC, FT	7/		1410.1	1399.5				
BASE ECC, FT	8/	1411.2						
LOWER LIMIT, FT		1379.0						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		7689.4	8228.6	7982.5			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		3661.0	3661.0	3661.0			
UPSTREAM DISCHARGE, KSFD	4/		2083.2	2083.2	2083.2			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1634.4	1095.2	1341.3			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1411.7	1401.6	1406.3			
MAR31 ORC, FT	7/		1399.9	1399.9	1399.9			
BASE ECC, FT	8/	1411.4						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7127.4	7627.1	7397.6	7743.2		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3511.0	3511.0	3511.0	3511.0		
UPSTREAM DISCHARGE, KSFD	4/		2060.6	2060.6	2060.6	2060.6		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		2023.8	1524.1	1753.6	1408.0		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1418.7	1409.8	1413.9	1407.6		
APR30 ORC, FT	7/		1399.9	1399.9	1399.9	1407.6		
BASE ECC, FT	8/	1413.7						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.5	65.5	67.2	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5335.4	5709.5	5535.9	5794.8	5805.9	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		3356.0	3356.0	3356.0	3356.0	3356.0	
UPSTREAM DISCHARGE, KSFD	4/		1283.9	1283.9	1283.9	1283.9	1283.9	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2884.1	2510.0	2683.6	2424.7	2413.6	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1433.1	1427.0	1429.8	1425.6	1425.4	
MAY31 ORC, FT	7/		1425.6	1425.6	1425.6	1425.6	1425.4	
BASE ECC, FT	8/	1425.4						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.3	30.3	31.1	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2468.1	2641.2	2562.0	2684.2	2689.8	2622.9
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1736.0	1736.0	1736.0	1736.0	1736.0	1736.0
UPSTREAM DISCHARGE, KSFD	4/		213.9	267.8	213.0	245.0	266.8	272.3
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3061.4	2942.2	2966.6	2876.4	2892.6	2965.0
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1435.9	1434.0	1434.4	1433.0	1433.3	1434.4
JUN30 ORC, FT	7/		1435.9	1434.0	1434.4	1433.0	1433.3	1434.4
BASE ECC, FT	8/	1438.2						
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 BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF THE ARC OR CRC1 IN DOP

Table 3M: 2004 Variable Refill Curve Arrow Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			20.9	23.7	22.2	22.2	20.2	15.1
& IN HM^3	**		22946.7	23741.8	22173.8	22209.0	20192.5	15087.7
95% FORECAST ERROR FOR DATE, HM^3			3017.6	2415.5	2018.9	1750.8	1227.5	1227.5
95% CONF.DATE-31JULY INFLOW, HM^3	1/		19929.0	21326.3	20154.9	20458.5	18965.1	13860.0
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		19929.0					
MIN FEB1-JUL31 OUTFLOW, HM^3	3/		9678.8					
UPSTREAM DISCHARGE, HM^3	4/		4703.8					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		3211.4					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		428.5					
JAN31 ORC, M	7/		428.5					
BASE ECC, M	8/	429.6						
LOWER LIMIT, M		422.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		19430.7	20793.2				
MIN MAR1-JUL31 OUTFLOW, HM^3	3/		9336.2	9336.2				
UPSTREAM DISCHARGE, HM^3	4/		5113.2	5113.2				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		3776.6	2414.1				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		429.8	426.6				
FEB28 ORC, M	7/		429.8	426.6				
BASE ECC, M	8/	430.1						
LOWER LIMIT, M		420.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		18812.9	20132.1	19530.0			
MIN APR1-JUL31 OUTFLOW, HM^3	3/		8959.0	8959.0	8959.0			
UPSTREAM DISCHARGE, HM^3	4/		5096.8	5096.8	5096.8			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		3998.7	2679.5	3281.6			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		430.3	427.2	428.6			
MAR31 ORC, M	7/		426.7	426.7	426.7			
BASE ECC, M	8/	430.2						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		17437.9	18660.5	18099.0	18944.5		
MIN MAY1-JUL31 OUTFLOW, HM^3	3/		8590.0	8590.0	8590.0	8590.0		
UPSTREAM DISCHARGE, HM^3	4/		5041.5	5041.5	5041.5	5041.5		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		4951.4	3728.9	4290.4	3444.8		
VRC APR30 RESERVOIR CONTENT, METERS	6/		432.4	429.7	431.0	429.0		
APR30 ORC, M	7/		426.7	426.7	426.7	429.0		
BASE ECC, M	8/	430.9						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.		65.5	65.5	67.2	69.3	74.9		
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		3053.6	13968.9	13544.1	14177.6	14204.7	
MIN JUN1-JUL31 OUTFLOW, HM^3	3/		8210.8	8210.8	8210.8	8210.8	8210.8	
UPSTREAM DISCHARGE, HM^3	4/		3141.2	3141.2	3141.2	3141.2	3141.2	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		7056.2	6141.0	6565.7	5932.3	5905.1	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		436.8	435.0	435.8	434.5	434.5	
MAY31 ORC, M	7/		434.5	434.5	434.5	434.5	434.5	
BASE ECC, M	8/	434.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.		30.3	30.3	31.1	32.1	34.7	46.3	
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		6038.5	6462.0	6268.2	6567.2	6580.9	6417.2
MIN JUL1-JUL31 OUTFLOW, HM^3	3/		4247.3	4247.3	4247.3	4247.3	4247.3	4247.3
UPSTREAM DISCHARGE, HM^3	4/		523.3	655.2	521.1	599.4	652.8	666.2
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		7490.0	7198.4	7258.1	7037.4	7077.0	7254.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		437.7	437.1	437.2	436.8	436.9	437.2
JUN30 ORC, M	7/		437.7	437.1	437.2	436.8	436.9	437.2
BASE ECC, M	8/	438.4						
JUL 31 ORC, M			752.9	752.9	752.9	752.9	752.9	752.9

** 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 (8757.85 HM^3) MINUS 2/ PLUS 3/ MINUS /4.
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF THE ARC OR CRC1 IN DOP

Table 4: 2004 Variable Refill Curve Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1747.5	1729.6	1596.5	1629.4	1503.9	1143.7
& IN KSFD	**		881.0	872.0	804.9	821.5	758.2	576.6
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/		762.6	763.1	707.4	733.4	684.9	503.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		762.6					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		233.2					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		176.4					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1825.6					
JAN31 ORC, FT	7/		1825.6					
BASE ECC, FT	8/	1856.3						
LOWER LIMIT, FT		1802.2						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		745.9	746.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		230.4	230.4				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		190.3	189.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1827.6	1827.5				
FEB28 ORC, FT	7/		1809.5	1807.8				
BASE ECC, FT	8/	1833.8						
LOWER LIMIT, FT		1795.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		726.8	727.2	689.0			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		227.3	227.3	227.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		206.3	205.9	244.1			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1829.8	1829.7	1835.2			
MAR31 ORC, FT	7/		1809.5	1807.8	1815.9			
BASE ECC, FT	8/	1828.2						
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/		680.3	680.6	644.4	685.7		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		1800.0	1800.0	1800.0	1800.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		224.3	224.3	224.3	224.3		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		249.8	249.5	285.7	244.4		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1835.9	1835.9	1840.9	1835.2		
APR30 ORC, FT	7/		1809.5	1807.8	1815.8	1808.2		
BASE ECC, FT	8/	1831.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		515.5	515.8	488.8	520.0	519.2	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		2000.0	2000.0	2000.0	2000.0	2000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		168.5	168.5	168.5	168.5	168.5	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		358.8	358.5	385.5	354.3	355.1	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1850.4	1850.4	1853.9	1849.9	1850.0	
MAY31 ORC, FT	7/		1846.7	1846.7	1846.7	1846.7	1846.7	
BASE ECC, FT	8/	1846.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		241.8	241.9	229.2	244.2	243.8	236.1
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		3500.0	3500.0	3500.0	3500.0	3500.0	3500.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		108.5	108.5	108.5	108.5	108.5	108.5
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		572.5	572.4	585.1	570.1	570.5	578.2
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1876.7	1876.7	1878.2	1876.5	1876.5	1877.4
JUN30 ORC, FT	7/		1875.7	1875.7	1875.7	1875.7	1875.7	1875.7
BASE ECC, FT	8/	1875.7						
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 (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 4M: 2004 Variable Refill Curve Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			2.2	2.1	1.97	2.01	1.86	1.41
& IN HM^3	**		2155.5	2133.4	1969.3	2009.9	1855.0	1410.7
95% FORECAST ERROR FOR DATE, HM^3			289.7	266.4	238.5	215.6	179.3	179.3
95% CONF.DATE-31JULY INFLOW, HM^3	1/		1865.8	1867.0	1730.7	1794.3	1675.7	1231.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		1865.8					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		570.6					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		431.6					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		740.9					
JAN31 ORC, M	7/		735.8					
BASE ECC, M	8/	735.8						
LOWER LIMIT, M		722.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		1824.9	1825.9				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		563.7	563.7				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		465.6	464.6				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		740.1	737.0				
FEB28 ORC, M	7/		734.9	734.9				
BASE ECC, M	8/	734.9						
LOWER LIMIT, M		707.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		1778.2	1779.2	1685.7			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		556.1	556.1	556.1			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		504.7	503.8	597.2			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		739.3	736.2	737.9			
MAR31 ORC, M	7/		734.0	734.0	734.0			
BASE ECC, M	8/	734.0						
LOWER LIMIT, M		697.3						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		1664.4	1664.4	1576.6	1677.6		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		283.2	283.2	283.2	283.2		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		548.8	548.8	548.8	548.8		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		611.2	610.4	699.0	598.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		739.9	737.2	738.7	739.2		
APR30 ORC, M	7/		731.4	731.4	731.4	731.4		
BASE ECC, M	8/	731.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		1261.2	1262.0	1195.9	1272.2	1270.3	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		311.5	311.5	311.5	311.5	28.3	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		412.3	412.3	412.9	412.3	412.3	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		877.8	877.1	877.1	866.8	868.8	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		564.0	564.0	565.1	563.9	563.9	
MAY31 ORC, M	7/		562.9	562.9	562.9	562.9	562.9	
BASE ECC, M	8/	562.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		591.6	591.8	560.8	597.5	596.5	577.6
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		311.5	311.5	311.5	311.5	28.3	311.5
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		265.5	265.5	265.5	265.5	265.5	265.5
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		1400.7	1400.4	1431.5	1394.8	1395.8	1414.6
VRC JUN30 RESERVOIR CONTENT, METERS	6/		572.0	572.0	572.5	572.0	572.0	572.2
JUN30 ORC, M	7/		571.7	571.7	571.7	571.7	571.7	571.7
BASE ECC, M	8/	571.71						
JUL 31 ORC, M			576.7	576.7	576.7	576.7	576.7	576.7

** 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 (1726.81 HM^3) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 5: 2004 Variable Refill Curve Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			5761	5656	5347	5296	4975	4505
PROBABLE DATE-31JULY INFLOW, KSFD			2904.5	2851.6	2695.8	2670.1	2508.2	2271.3
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	79.7	150.2	254.1	571.7	1125.8
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2017.7	2165.5	1993	1882.6	1462	778
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.96					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		1956.4					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1337					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1891.1					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2430.9					
JAN31 ORC, FT	7/		2413.9					
BASE ECC, FT	9/	2413.9						
LOWER LIMIT, FT		2371.2						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.18	97.14				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		1900.3	2103.6				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1225	1225				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1835.2	1631.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2428.2	2417.9				
FEB28 ORC, FT	7/		2411.1	2411.1				
BASE ECC, FT	9/	2411.1						
LOWER LIMIT, FT		2320.8						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.81	93.66	96.42			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		1832.3	2028.2	1921.7			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1101	1101	1101			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1779.2	1583.3	1689.8			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2425.4	2415.3	2420.9			
MAR31 ORC, FT	7/		2408.2	2408.2	2408.2			
BASE ECC, FT	9/	2408.2						
LOWER LIMIT, FT		2288.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.7	85.29	87.8	91.07		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1668.7	1847	1749.9	1714.4		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		10000	10000	10000	10000		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		981	981	981	981		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1822.8	1644.5	1741.6	1777.1		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2427.5	2418.5	2423.5	2425.3		
APR30 ORC, FT	7/		2399.5	2399.5	2399.5	2399.5		
BASE ECC, FT	9/	2399.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.28	57.02	58.7	60.88	66.85	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1115.4	1234.8	1169.9	1146.1	977.3	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		11000	11000	11000	11000	11000	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		671	671	671	671	671	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2066.1	1946.7	2011.6	2035.4	2204.2	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2439.2	2433.6	2436.6	2437.8	2445.5	
MAY31 ORC, FT	7/		2424.2	2424.2	2424.2	2424.2	2424.2	
BASE ECC, FT	9/	2424.2						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.22	20.81	21.58	23.7	35.45
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		395.5	437.9	414.7	406.3	346.5	275.8
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		11000	11000	11000	11000	11000	11000
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		341	341	341	341	341	341
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2456	2413.6	2436.8	2445.2	2505	2510.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2456.6	2454.8	2455.8	2456.2	2458.8	2459
JUN30 ORC, FT	7/		2456.6	2454.8	2455.8	2456.2	2458.8	2459
BASE ECC, FT	9/	2459.0						
JUL 31 ORC, FT			2459	2459	2459	2459	2459	2459
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		103	100	92.9	84.2	81.6	85.1

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW. 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
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 VRC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT
8/ MEASURED AT THE DALLES USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.
9/ HIGHER OF ARC OR CRC1 IN DOP

Table 5M: 2004 Variable Refill Curve Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			7.11	6.98	6.60	6.53	6.14	5.56
PROBABLE DATE-31JULY INFLOW, HM^3	**		7106.2	6976.7	6595.6	6532.7	6136.6	5557.0
95% FORECAST ERROR FOR DATE, HM^3			2169.6	1483.6	1351.8	1305.0	1160.9	899.1
OBSERVED JAN1-DATE INFLOW, HM^3			0.00	195.0	367.5	621.7	1398.7	2754.4
95% CONF.DATE-31JULY INFLOW, HM^3	1/		4936.5	5298.1	4876.1	4606.0	3576.9	1903.5
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.96					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		4786.5					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		3271.1					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		4626.8					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		740.9					
JAN31 ORC, M	7/		735.8					
BASE ECC, M	9/		735.8					
LOWER LIMIT, M		722.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.18	97.14				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		4649.3	5146.7				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		2997.1	2997.1				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		4490.0	3992.6				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		740.1	737.0				
FEB28 ORC, M	7/		734.9	734.9				
BASE ECC, M	9/	734.9						
LOWER LIMIT, M		707.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.81	93.66	96.42			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		4482.9	4962.2	4701.6			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		2693.7	2693.7	2693.7			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		4353.0	3873.7	4134.3			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		739.3	736.2	737.9			
MAR31 ORC, M	7/		734.0	734.0	734.0			
BASE ECC, M	9/	734.0						
LOWER LIMIT, M		697.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.70	85.29	87.80	91.07		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		4082.6	4518.9	4281.3	4194.5		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		283.2	283.2	283.2	283.2		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		2400.1	2400.1	2400.1	2400.1		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		4459.7	4023.4	4261.0	4347.9		
VRC APR30 RESERVOIR CONTENT, METERS	6/		739.9	737.2	738.7	739.2		
APR30 ORC, M	7/		731.4	731.4	731.4	731.4		
BASE ECC, M	9/	731.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.28	57.02	58.70	60.88	66.85	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		2728.9	3021.1	2862.3	2804.1	2391.1	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		311.5	311.5	311.5	311.5	311.5	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		1641.7	1641.7	1641.7	1641.7	1641.7	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		5054.9	4762.8	4921.6	4979.8	5983.2	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		743.5	741.8	742.7	743.0	745.4	
MAY31 ORC, M	7/		738.9	738.9	738.9	738.9	738.9	
BASE ECC, M	9/	738.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.60	20.22	20.81	21.58	23.70	35.45
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		967.6	1071.4	1014.6	994.1	847.8	674.8
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		311.5	311.5	311.5	311.5	311.5	311.5
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		834.3	834.3	834.3	834.3	834.3	834.3
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		6008.9	5905.1	5961.9	5982.4	6128.7	6142.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		748.8	748.2	748.5	748.7	749.4	749.5
JUN30 ORC, M	7/		748.8	748.2	748.5	748.7	749.4	749.5
BASE ECC, M	9/	749.5						
JUL 31 ORC, M			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, KM^3	8/		127.1	123.4	114.6	103.9	100.7	105.0

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW. 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (6142.19HM^3) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE VRC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT
8/ MEASURED AT THE DALLES USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.
9/ HIGHER OF ARC OR CRC1 IN DOP

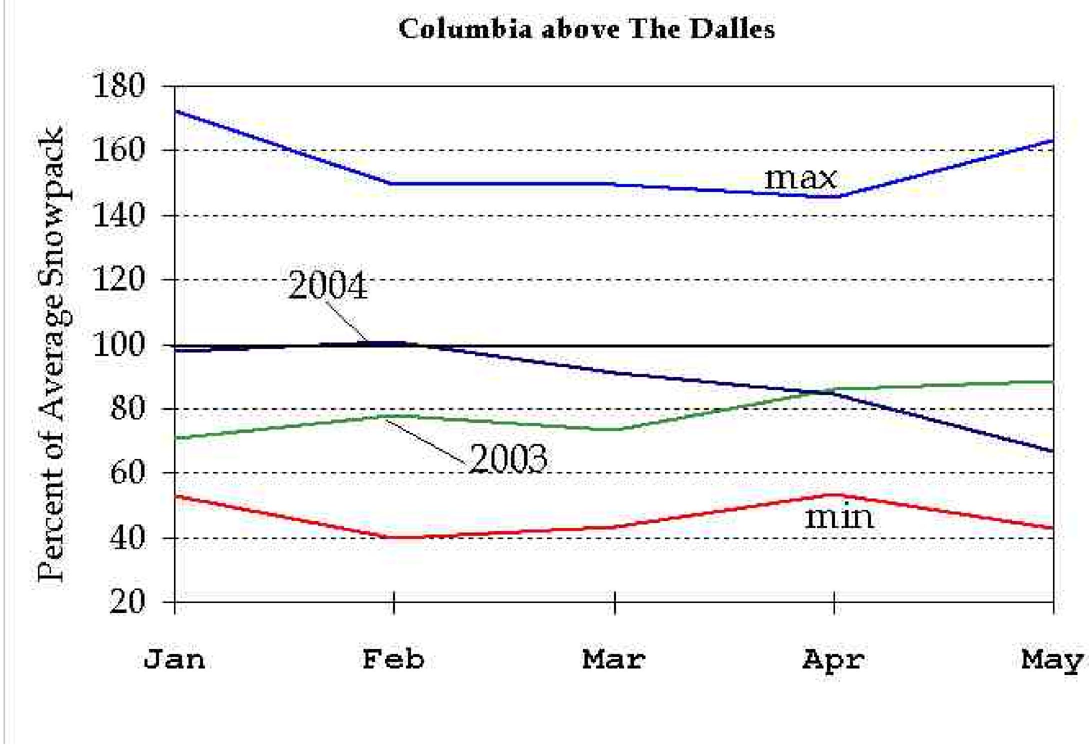
Table 6: Computation of Initial Controlled Flow

Columbia River at The Dalles
1 May 2004

	Maf	km^3
1 May Forecast of May – August Unregulated Runoff Volume	57.605	71.029
Less Estimated Depletions	1.500	1.85
Less Upstream Storage Corrections	17.124	21.115
Mica	5.879	7.249
Arrow	3.600	4.441
Duncan	1.382	1.704
Libby	2.033	2.507
Libby + Duncan Under Draft	0.000	0
Hungry Horse	0.598	0.737
Flathead Lake	0.500	0.617
Noxon Rapids	0.000	0
Pend Oreille Lake	0.500	0.617
Grand Coulee	1.610	1.985
Brownlee	0.092	0.113
Dworshak	0.680	0.838
John Day	0.250	0.308
Total	17.124	21.115r
Forecast of Adjusted Residual Runoff Volume	38.981	48.065
Computed Initial Control Flow from Chart 1 of Flood Control Operation Plan, in 1,000 cfs and m^3/s	230	6513

CHARTS

Chart 1: Columbia Basin Snowpack



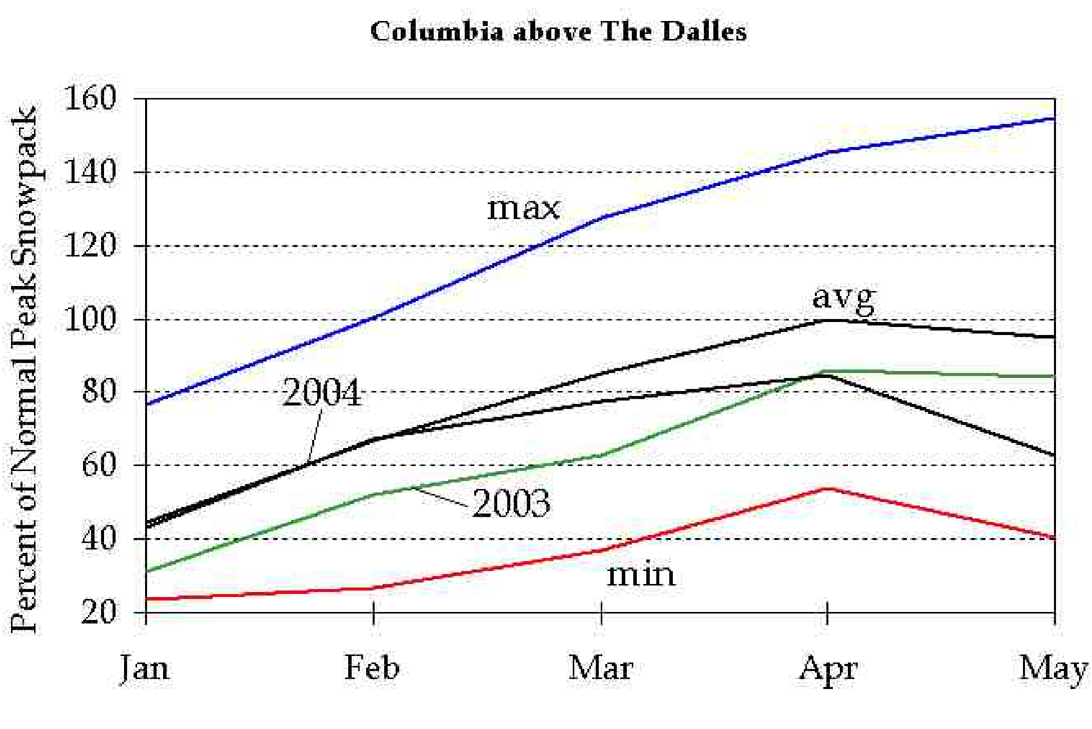


Chart 2: Seasonal Precipitation

Columbia River Basin
October 2003 – September 2004

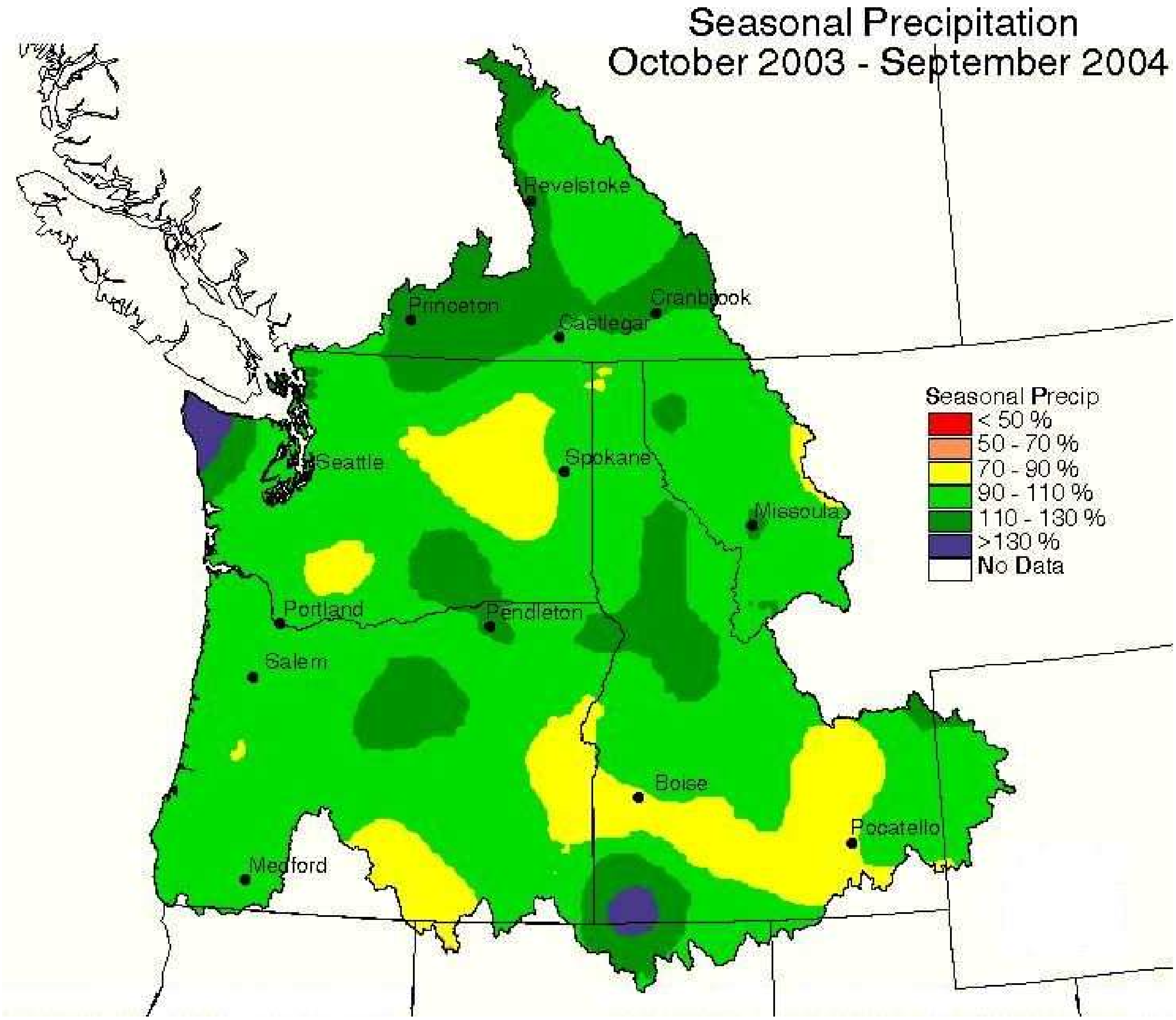


Chart 3: Accumulated Precipitation For WY 2004

At Primary Columbia River Basins

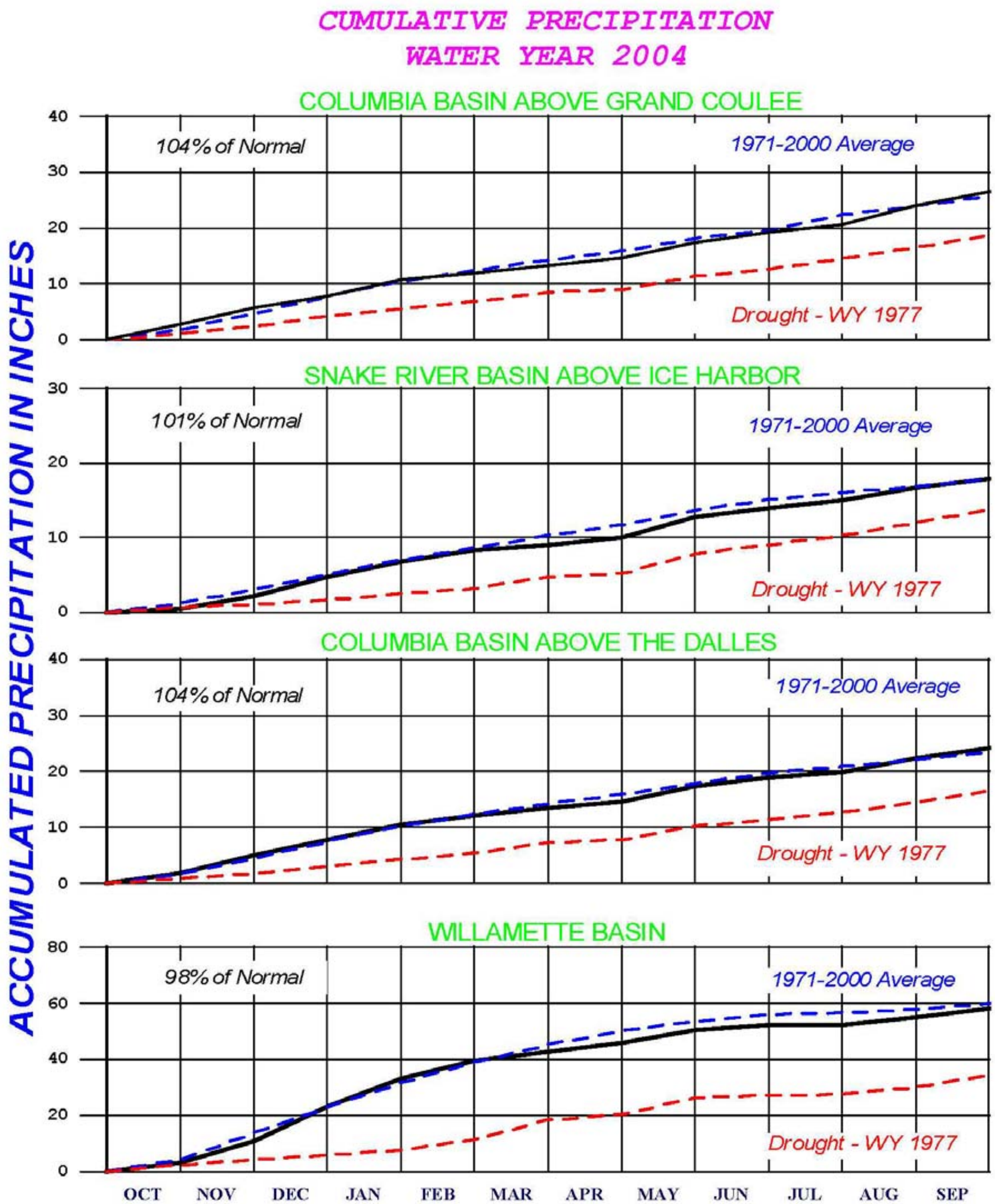


Chart 4: Pacific Northwest Monthly Temperature

Departures From Normal September 2004 – April 2004

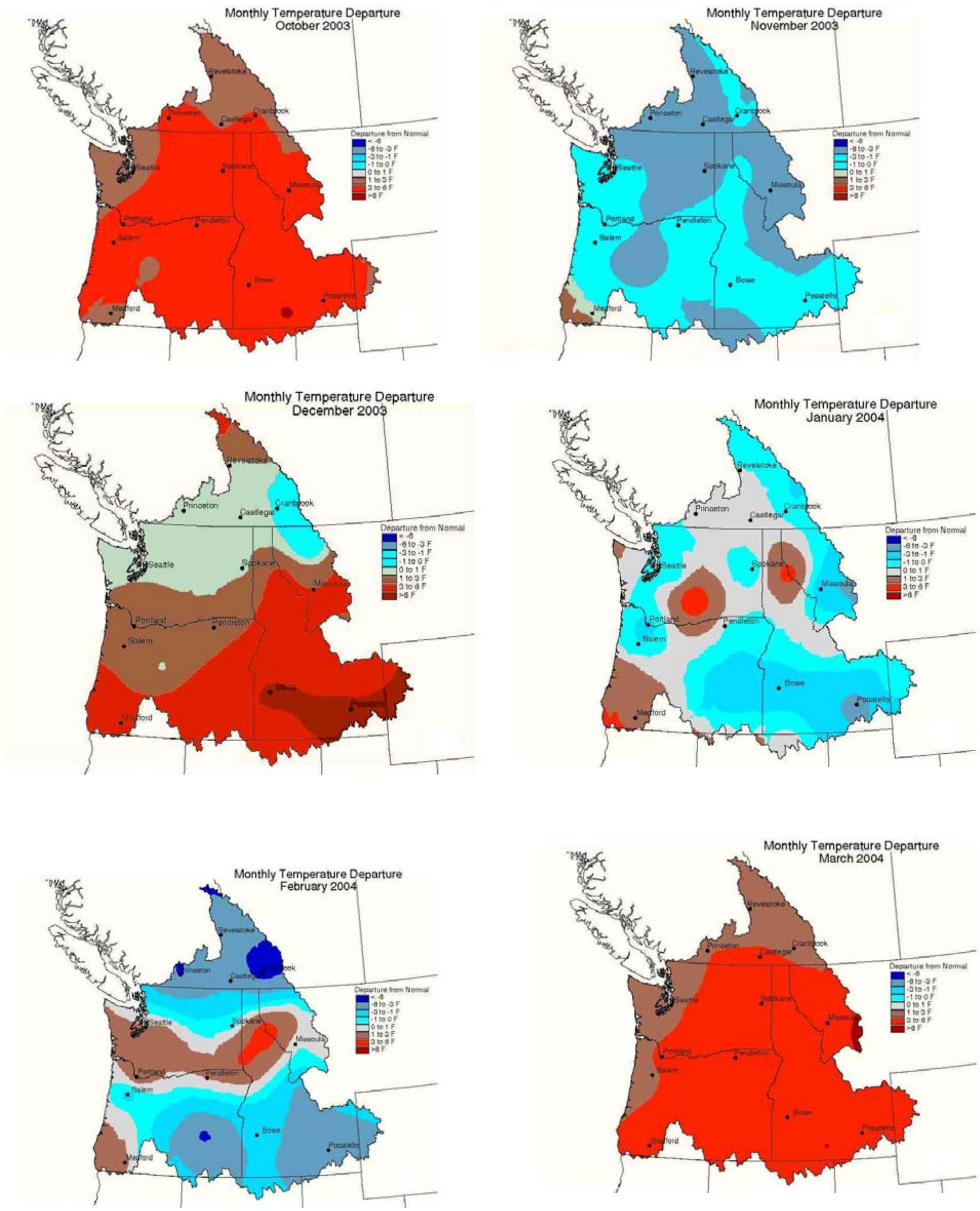


Chart 4: Pacific Northwest Monthly Temperature

Departures From Normal March 2004 – October 2003

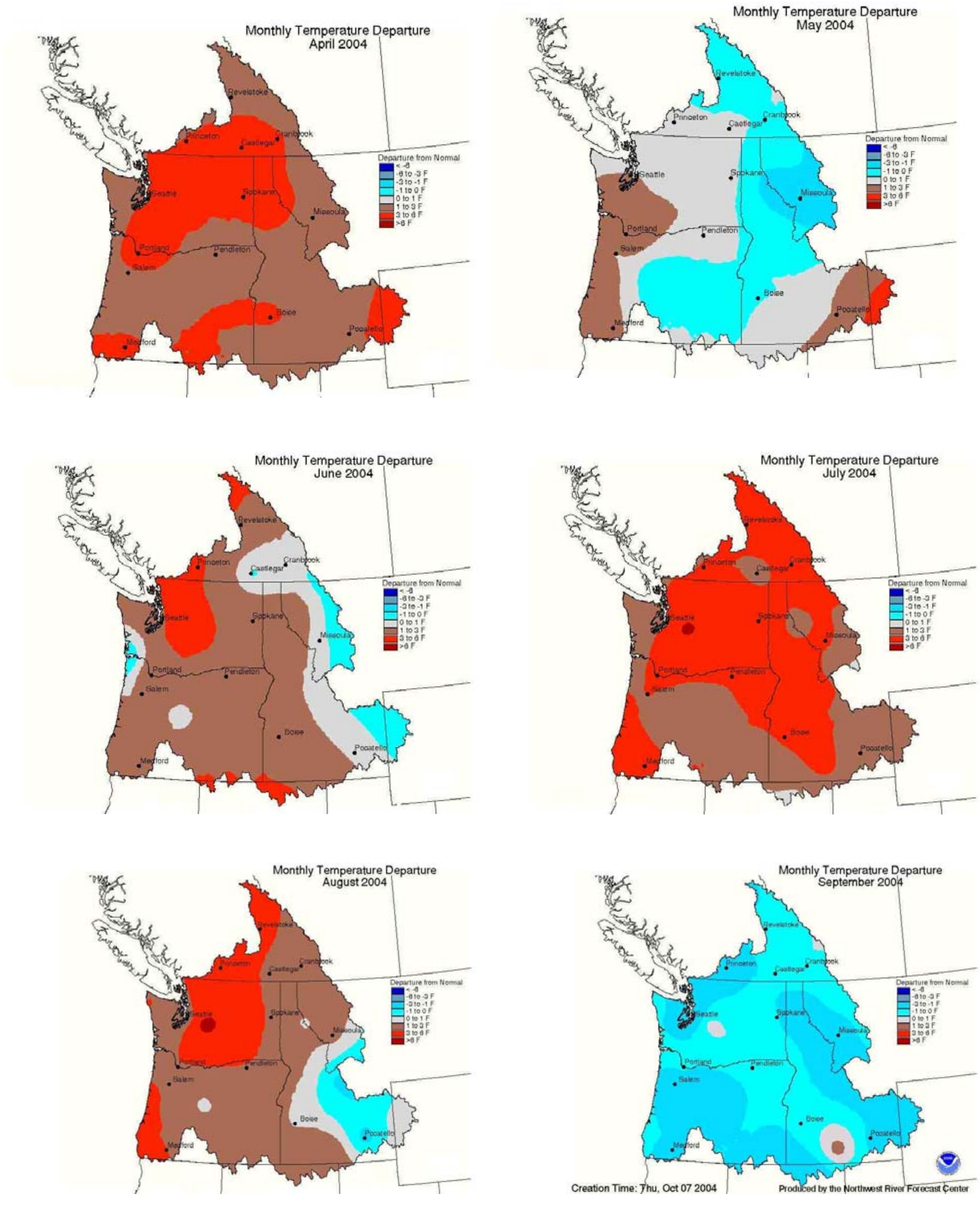


Chart 5: Regulation Of Mica

1 August 2003 – 30 September 2004

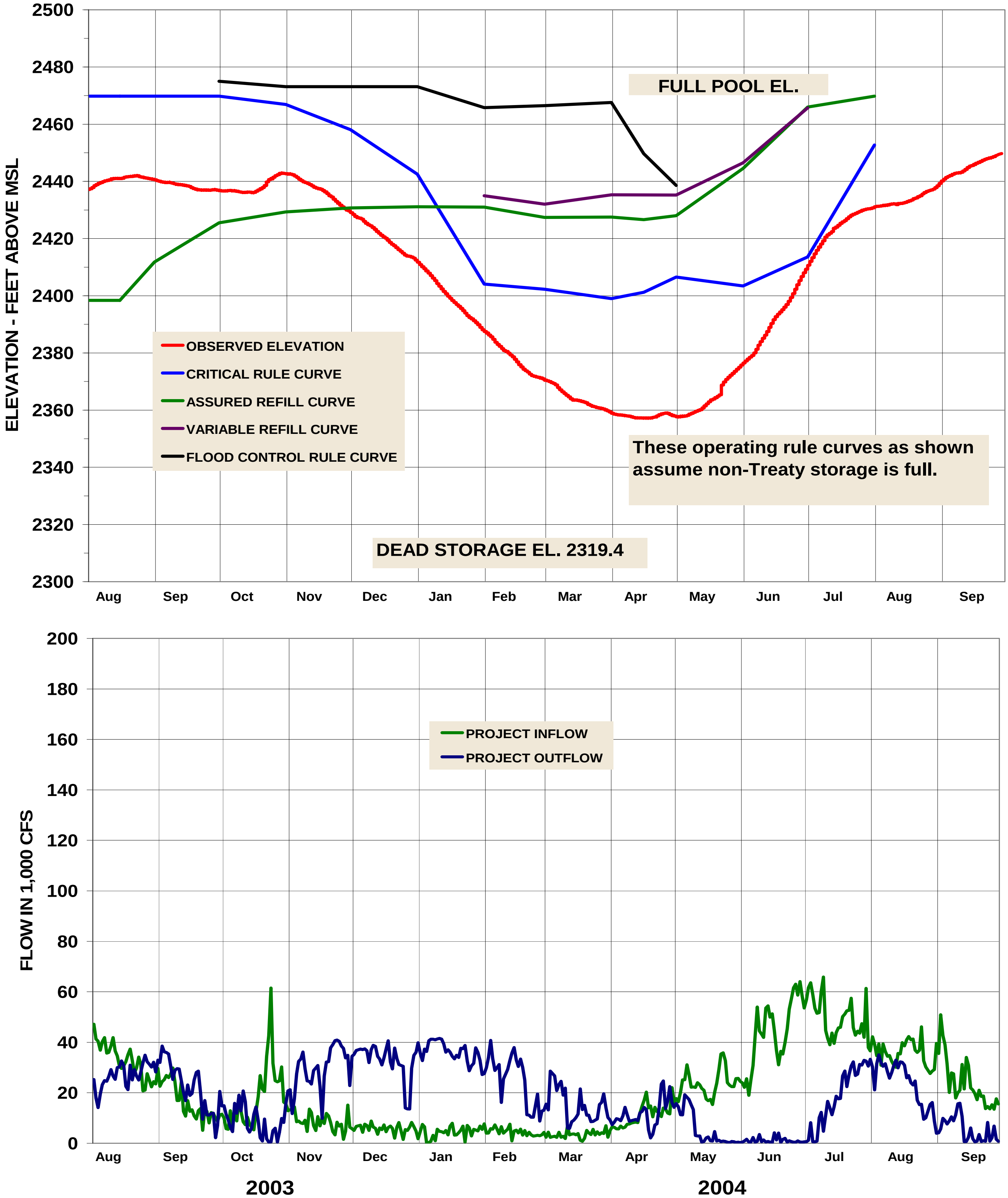
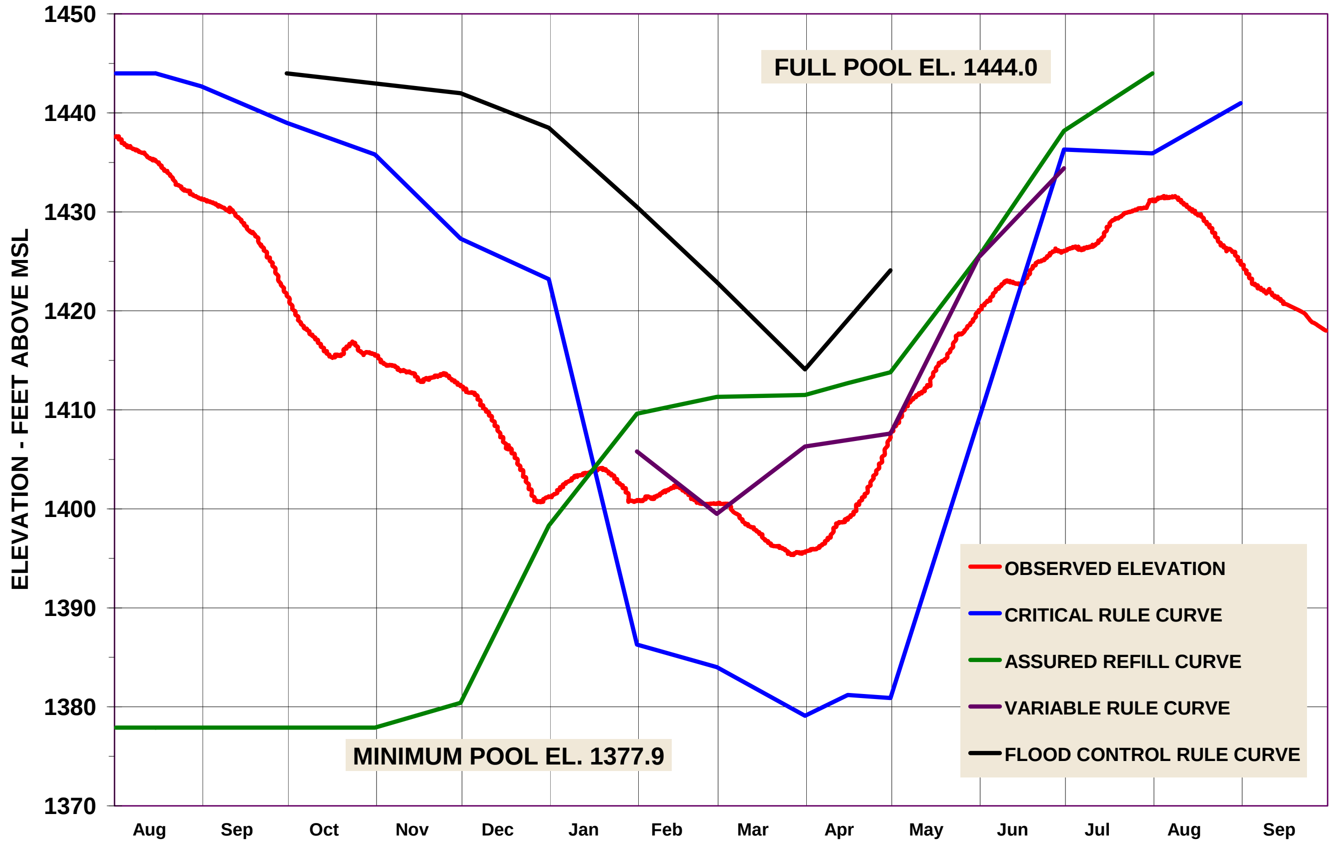


Chart 6: Regulation Of Arrow

1 August 2003 – 30 September 2004



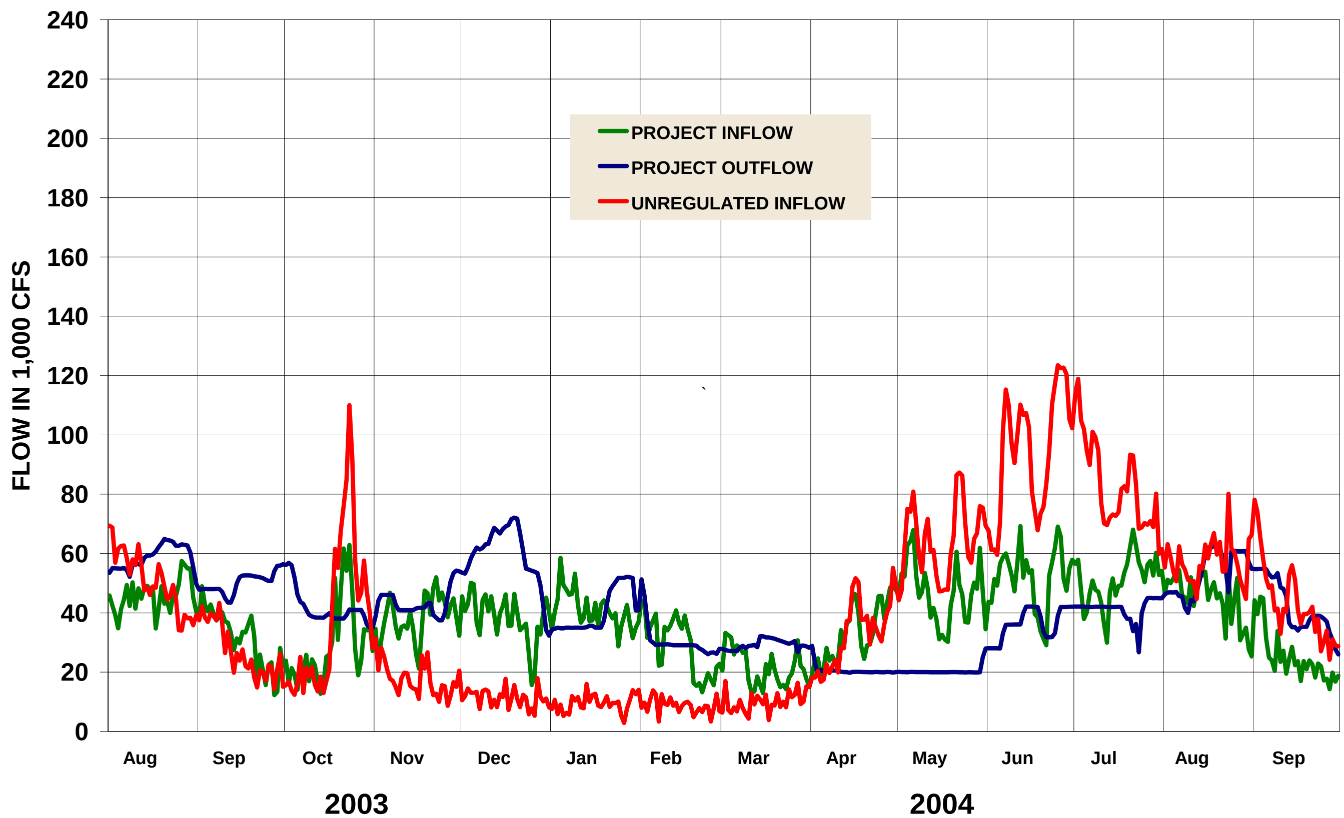


Chart 7: Regulation Of Duncan

1 August 2003 – 30 September 2004

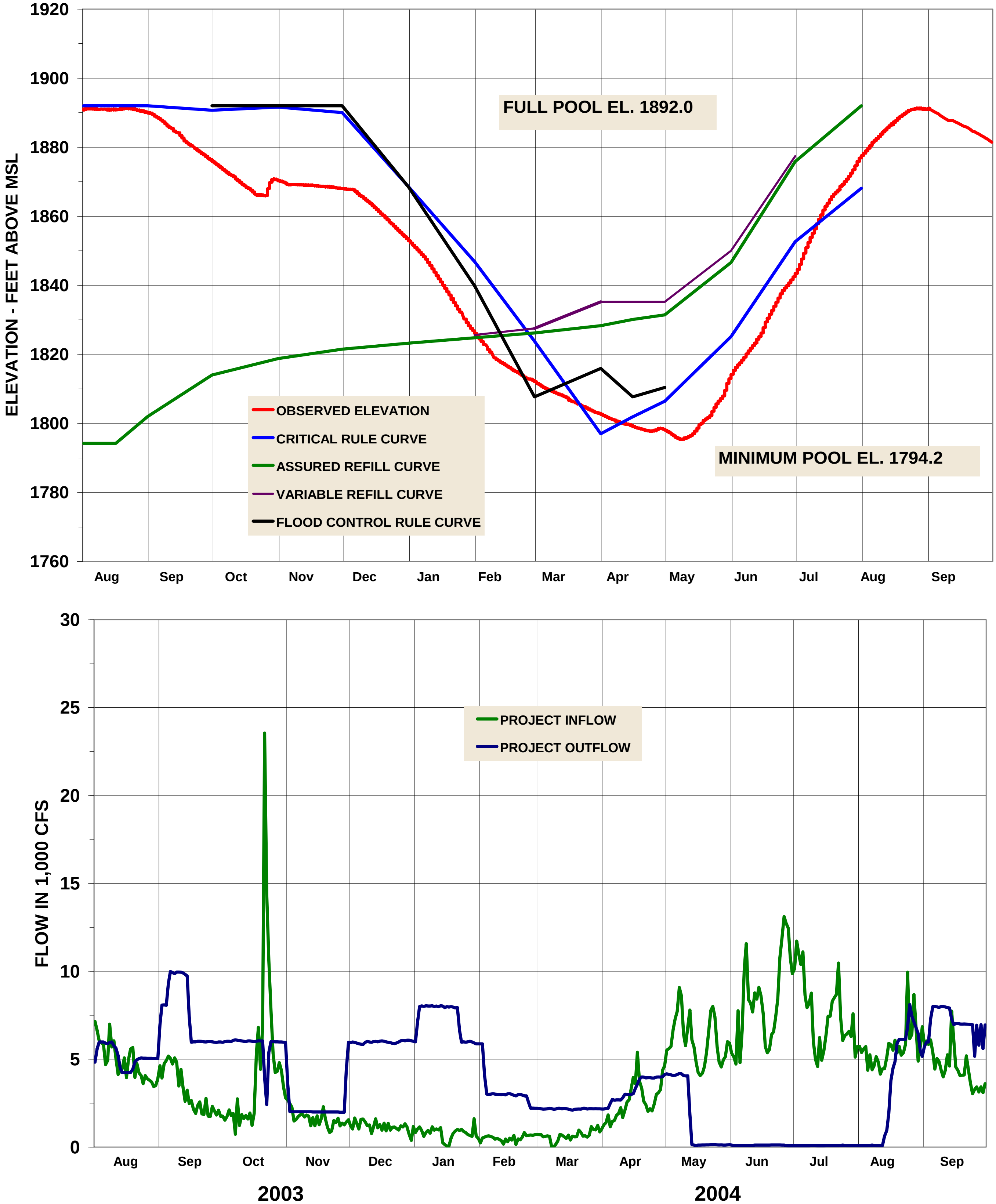
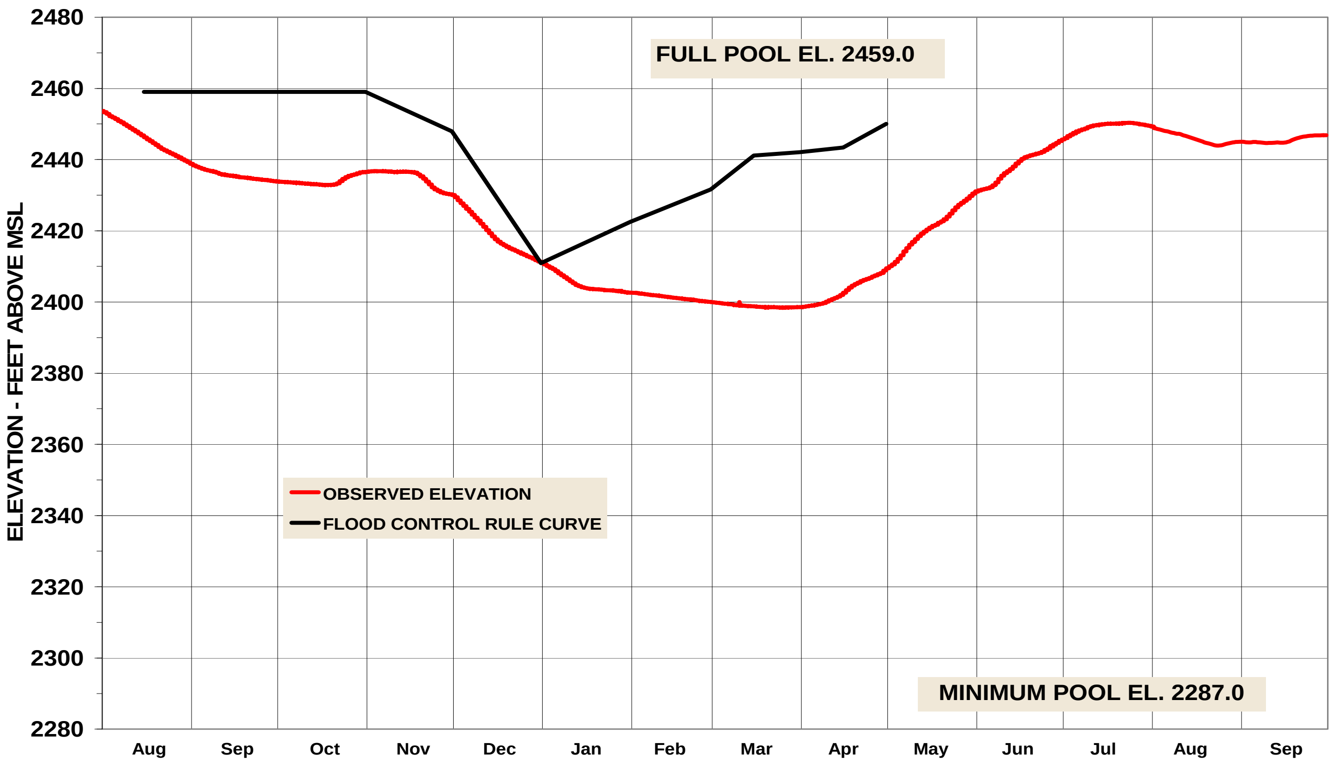


Chart 8: Regulation Of Libby

1 August 2003 – 30 September 2004



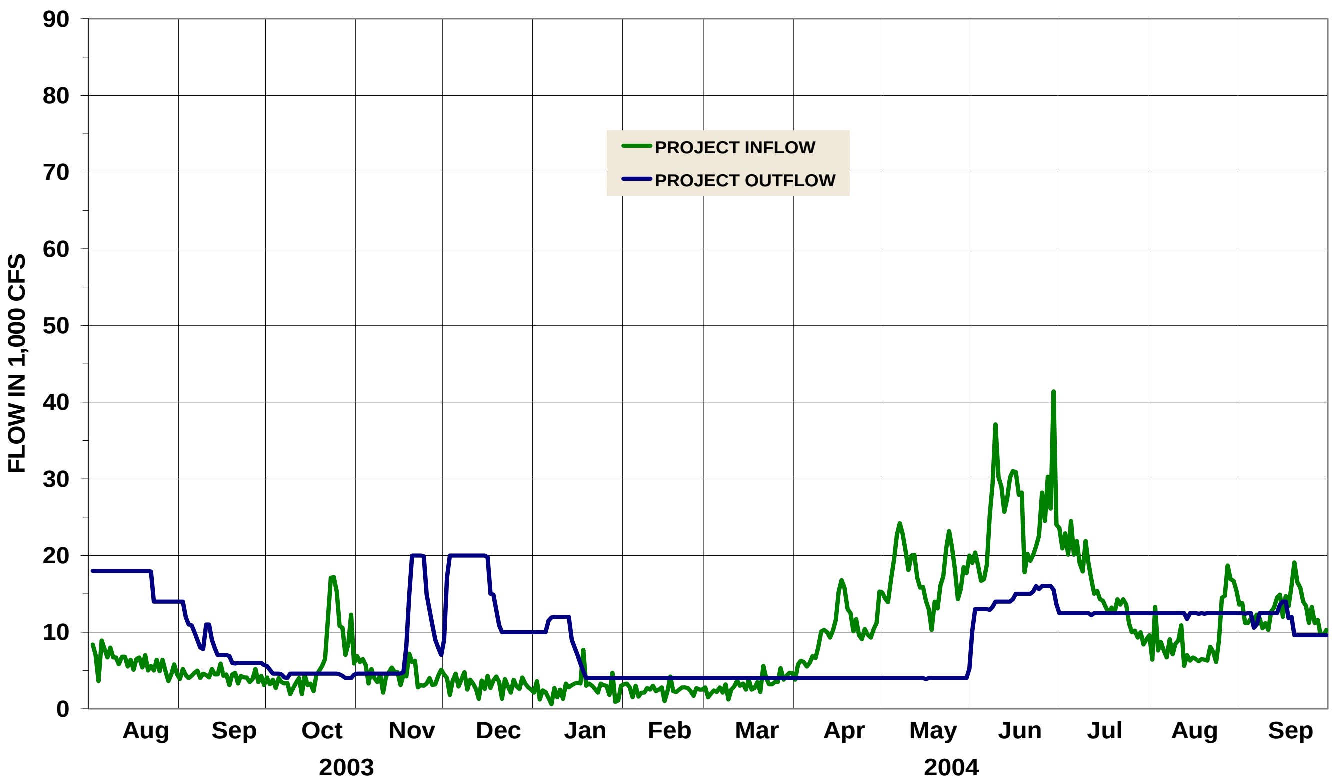
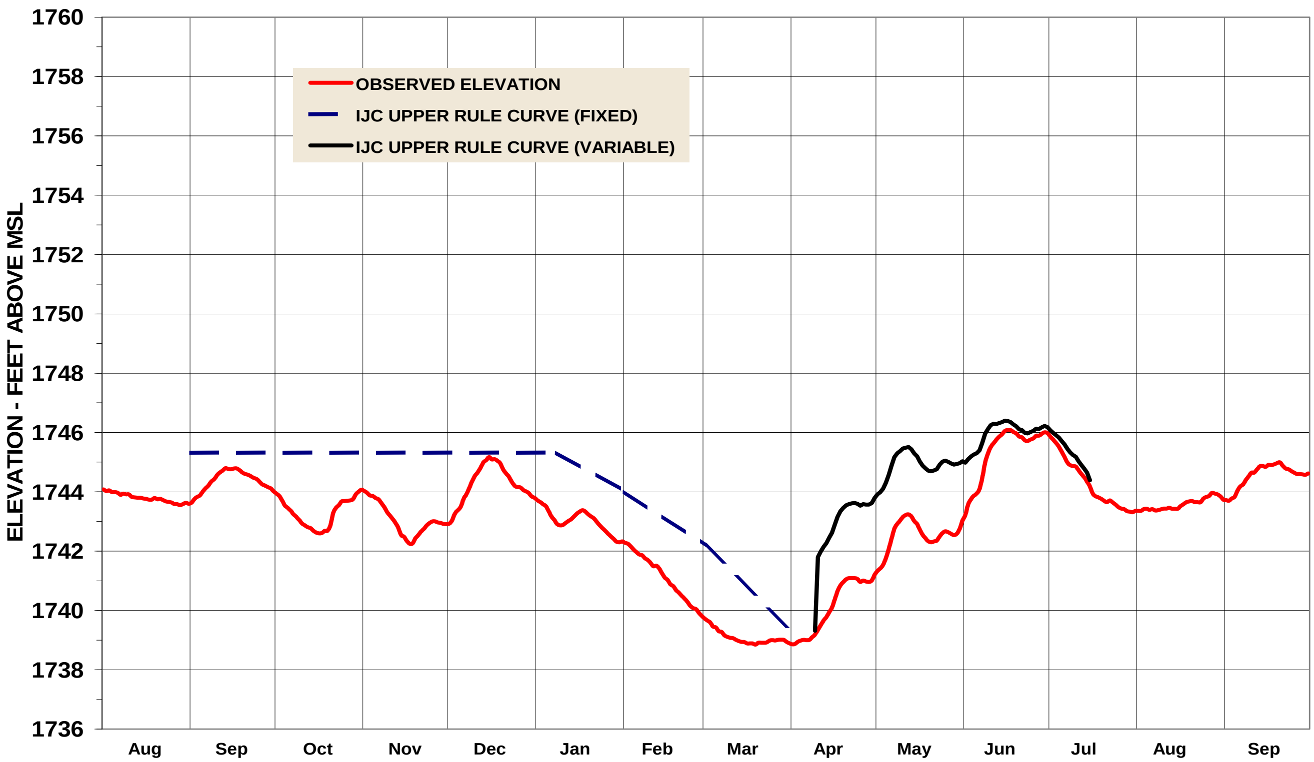


Chart 9: Regulation Of Kootenay Lake

1 August 2003 – 30 September 2004



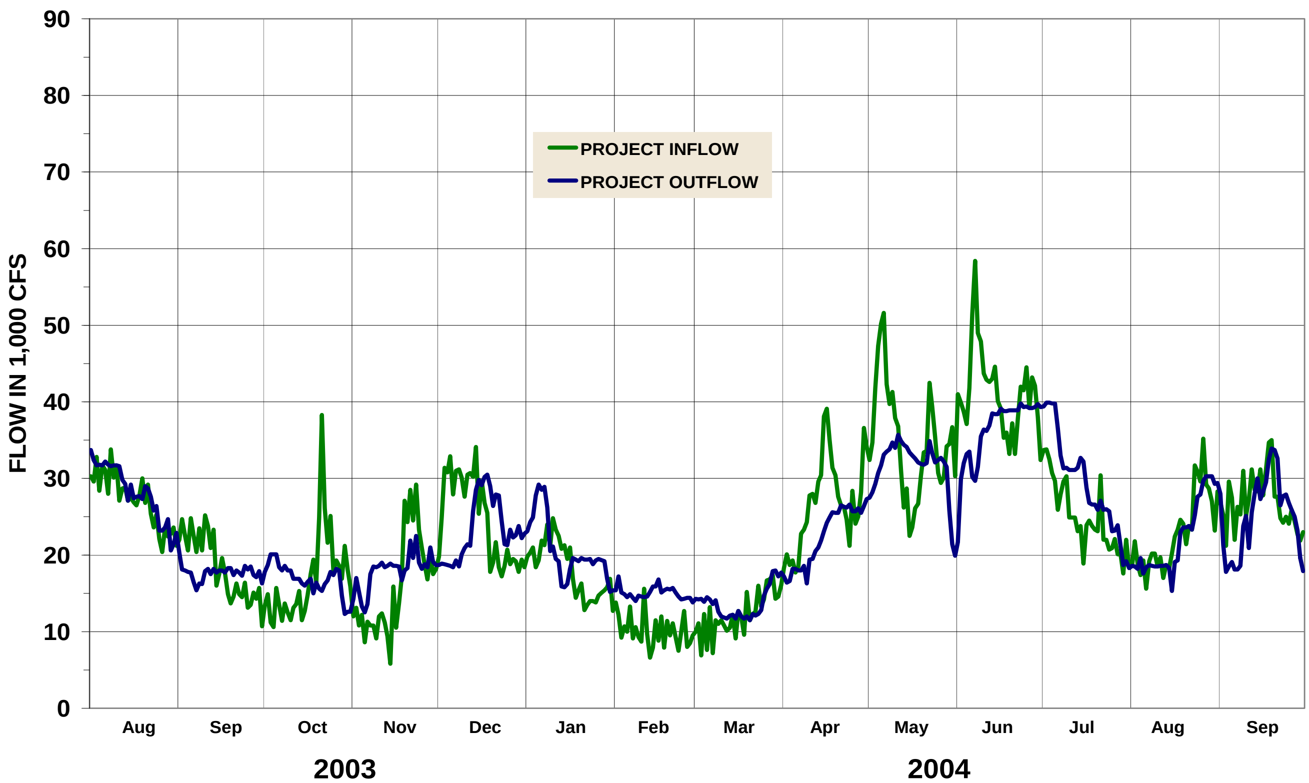


Chart 10: Columbia River At Birchbank

1 August 2003 – 30 September 2004

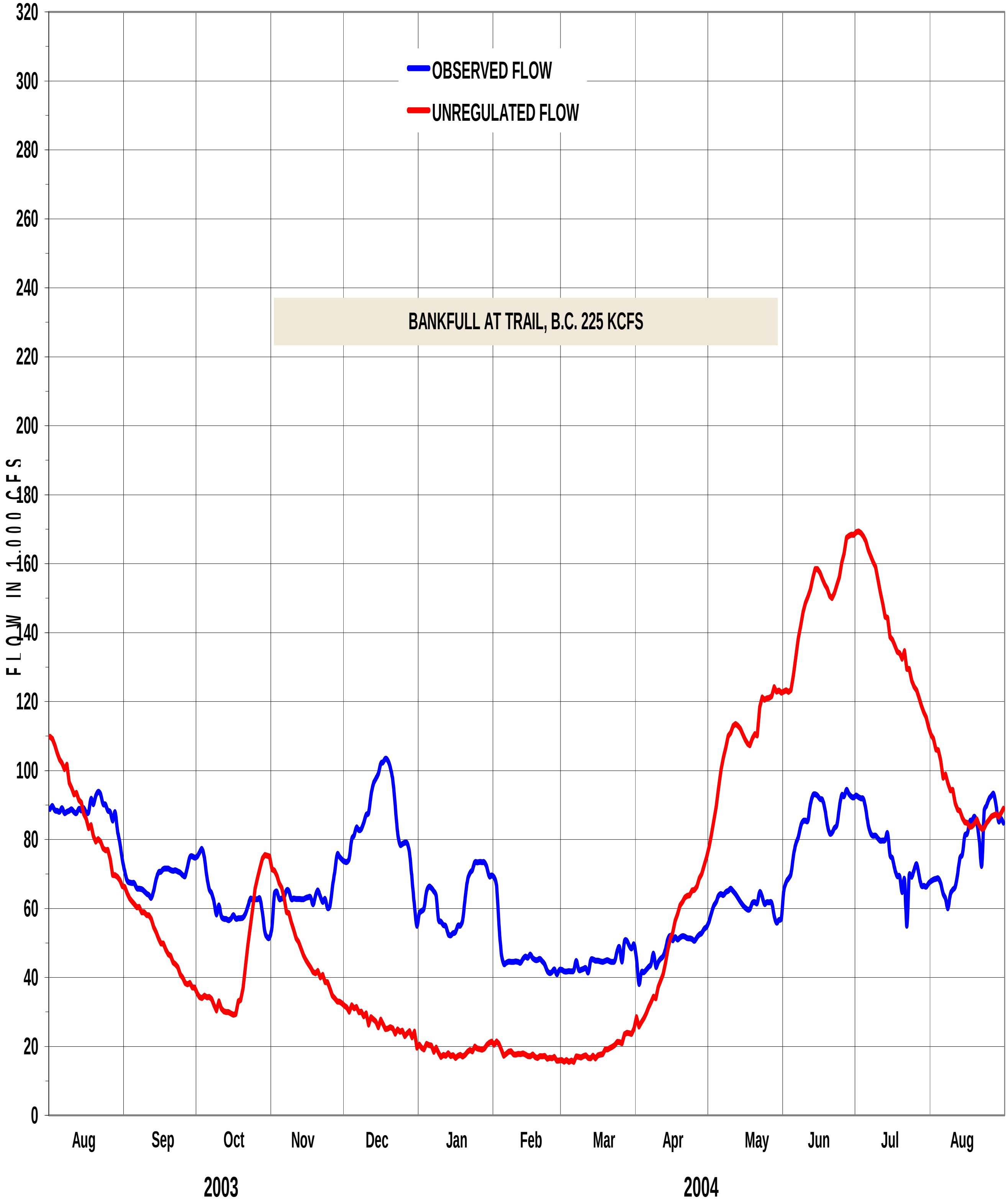
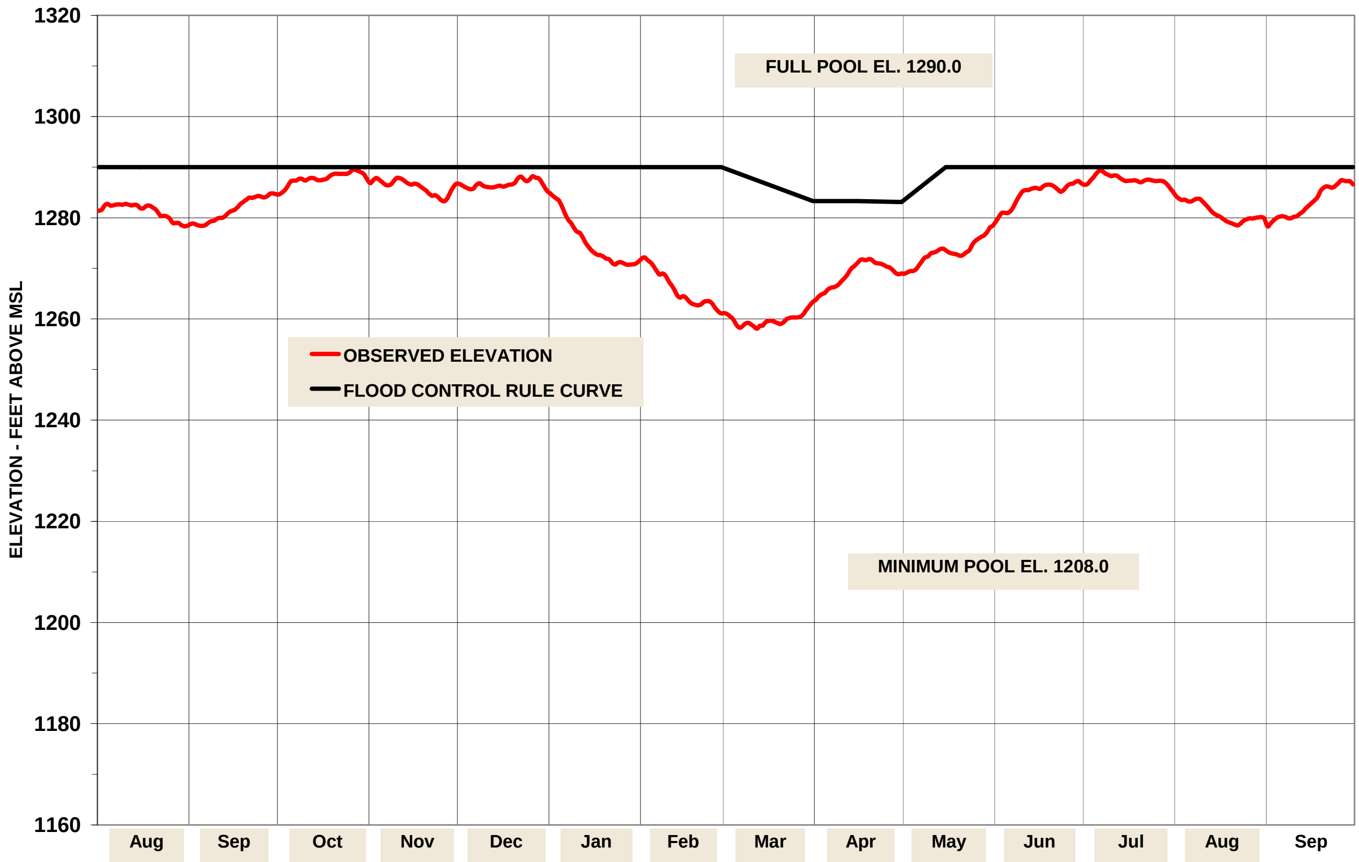


Chart 11: Regulation Of Grand Coulee

1 August 2003 – 30 August 2004



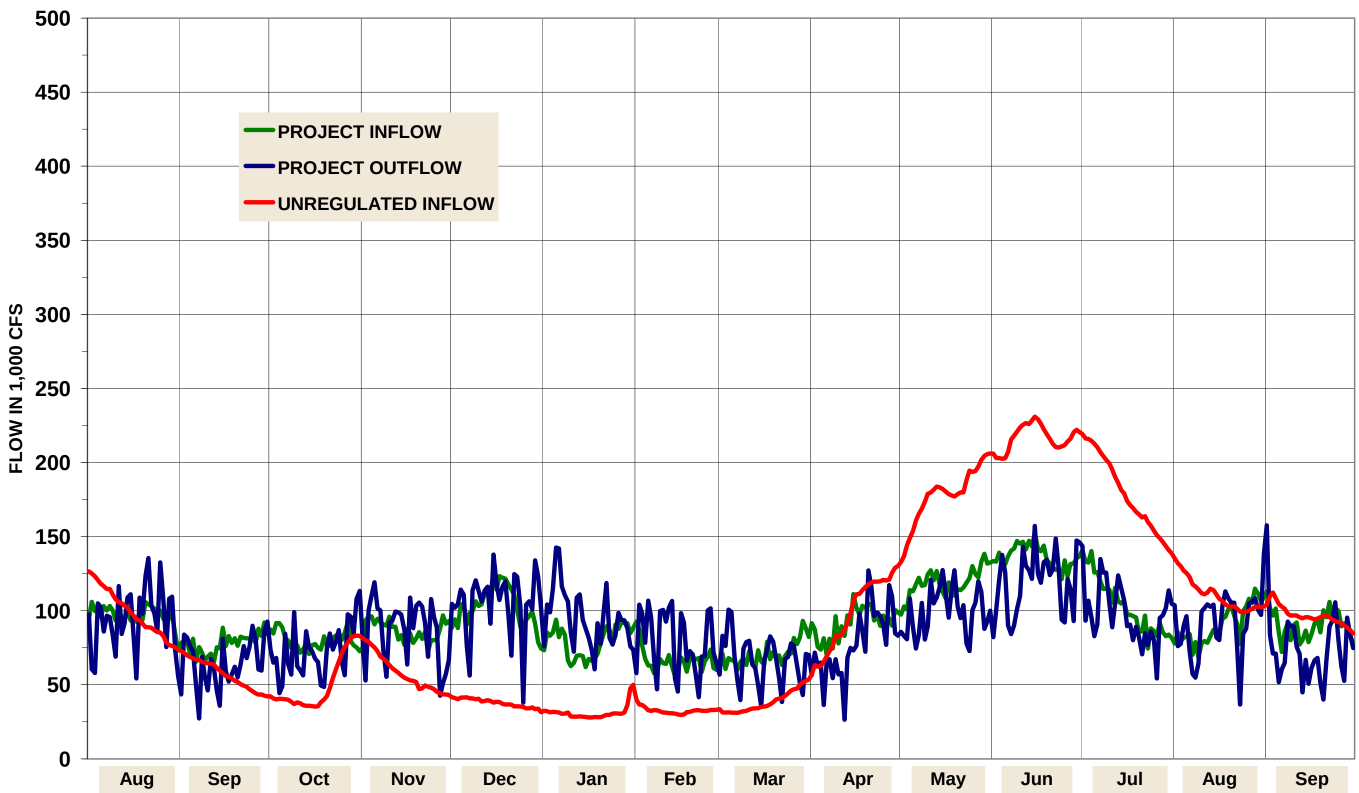


Chart 12: Columbia River At The Dalles

(Summary Hydrograph)
1 AUGUST 2003 – 30 SEPTEMBER 2004

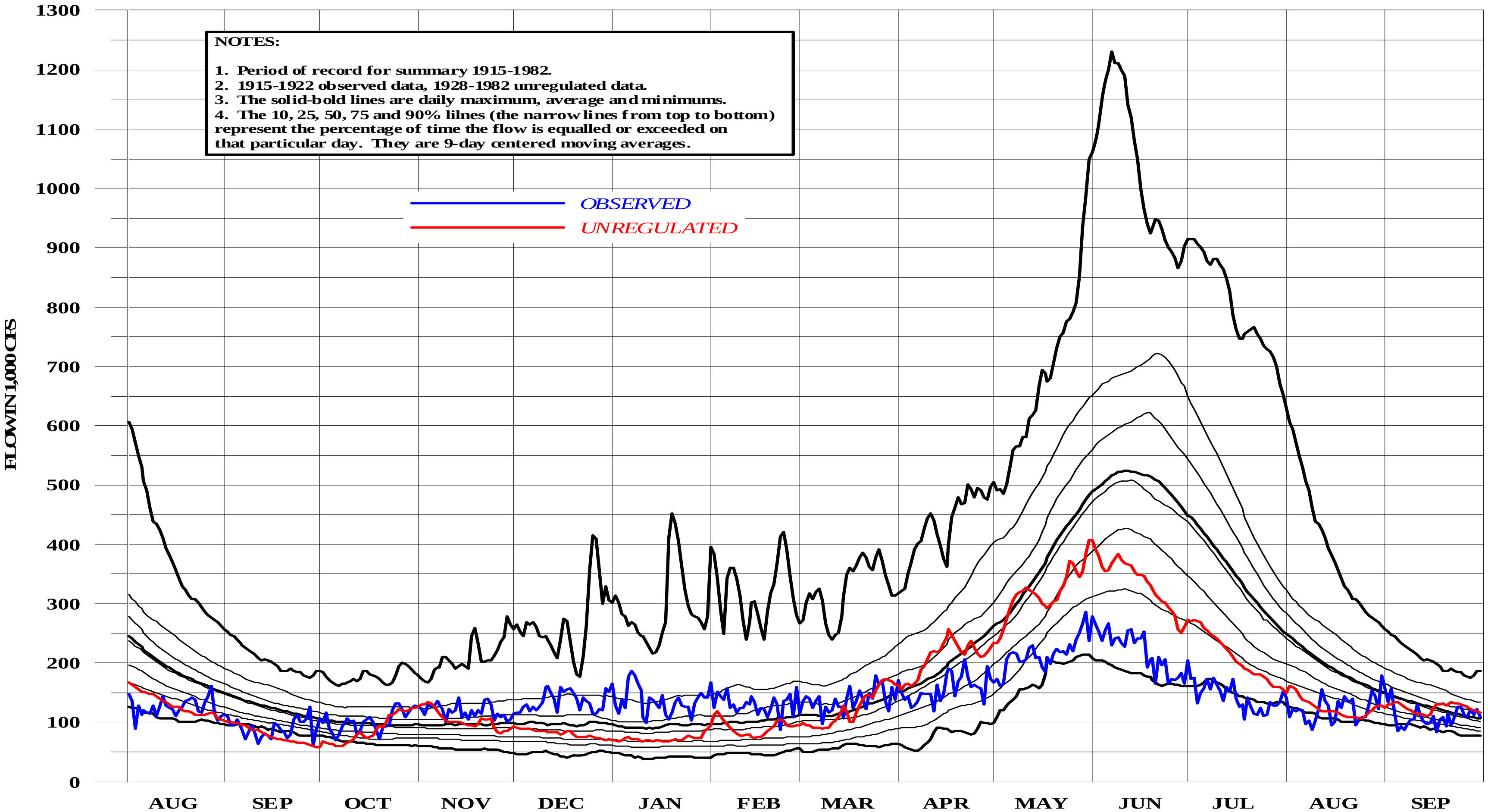


Chart 13: Columbia River At The Dalles
(Re-Regulation Plot)
1 April 2004 – 31 July 2004

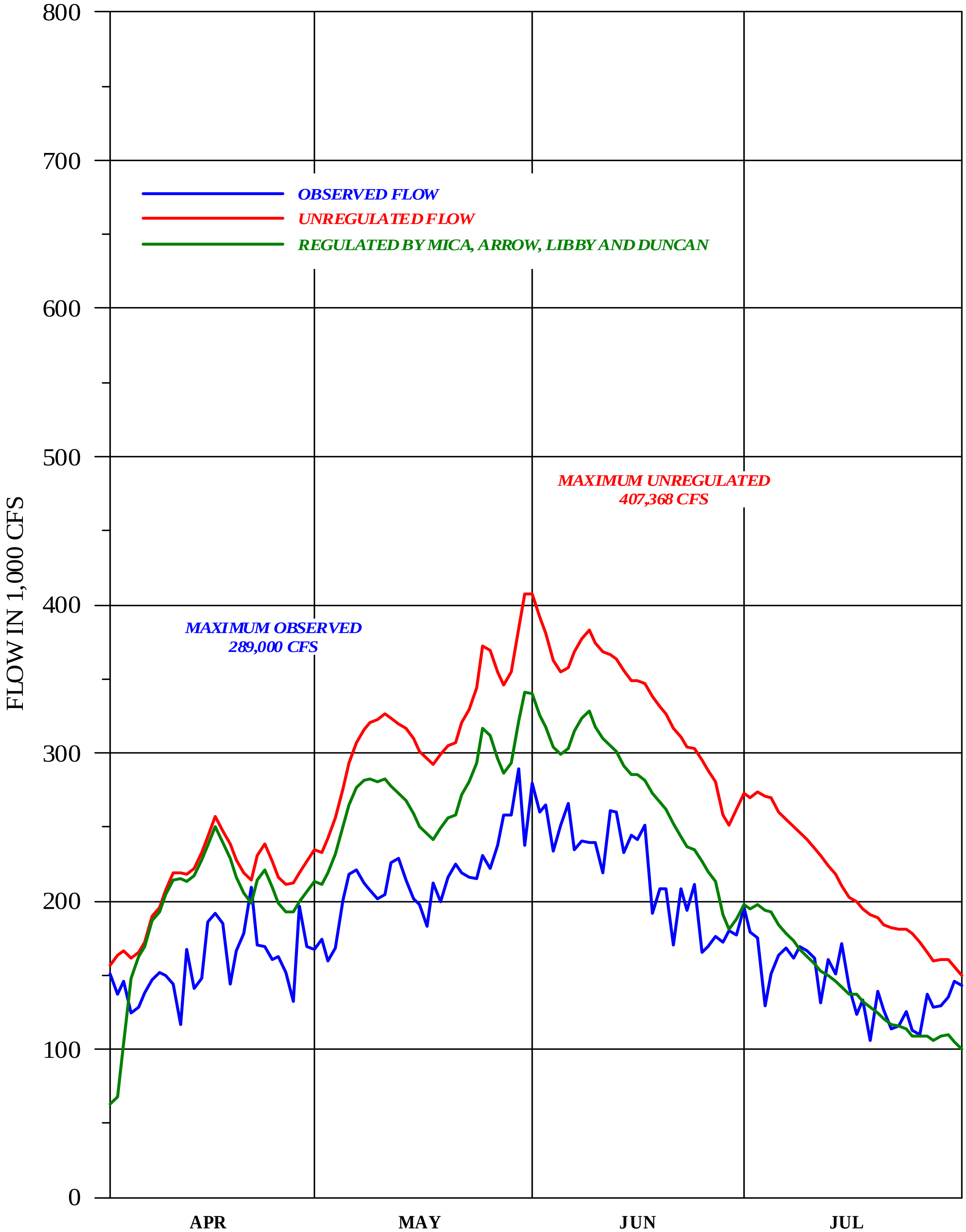


Chart 14: 2004 Relative Filling
Arrow And Grand Coulee