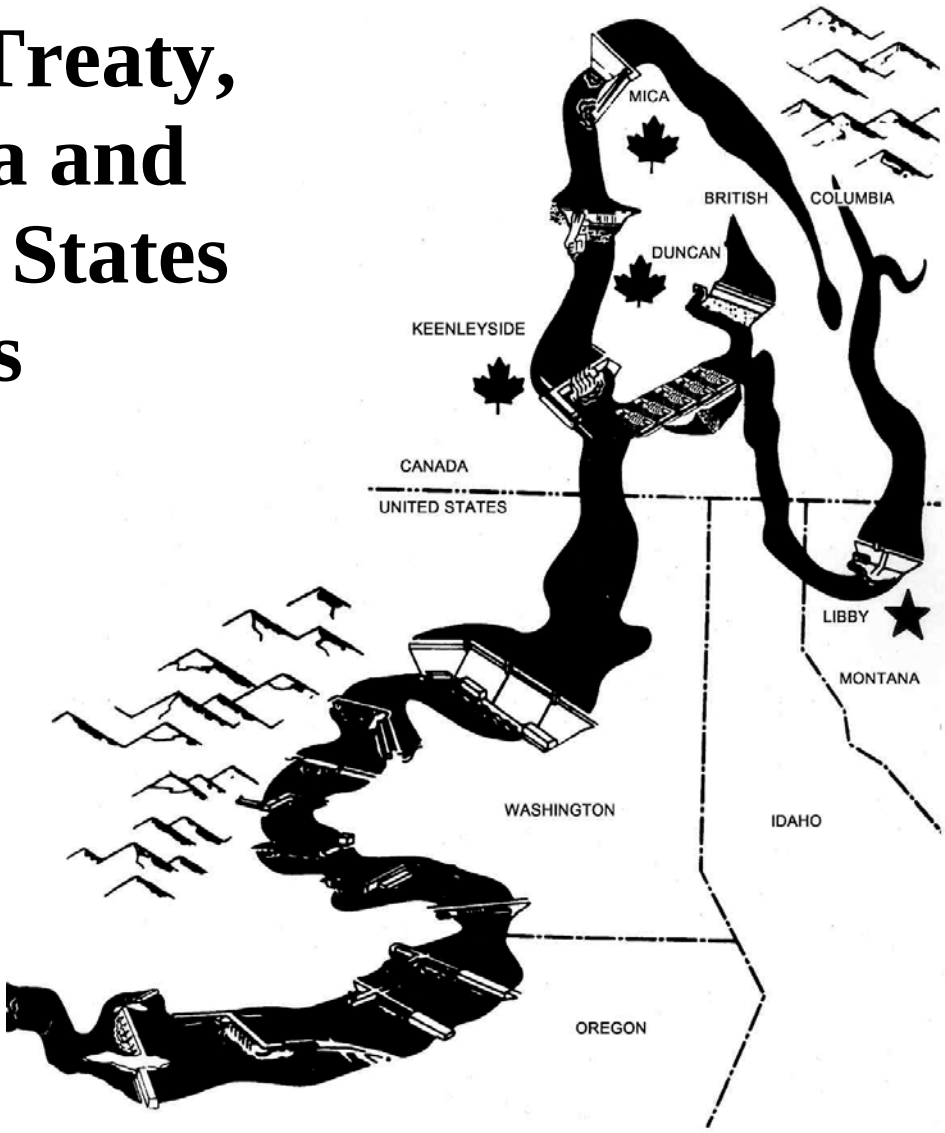
Annual Report of The Columbia River Treaty, Canada and United States Entities



1 August 2012 through
30 September 2013

2013 ANNUAL REPORT

OF THE

COLUMBIA RIVER TREATY

CANADA AND UNITED STATES ENTITIES

FOR THE PERIOD

1 AUGUST 2012 – 30 SEPTEMBER 2013

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EXECUTIVE SUMMARY

General

Precipitation and temperatures took a turn away from the previous two wet and cool operating years toward the warmer and drier side of normal. Water Year (WY) 2013 was a relatively average year, marked by neutral El Nino Southern Oscillation conditions, with the April-August runoff across the Basin, measured at The Dalles, being 107.4 km^3, (cubic kilometers) (87.05 Million acre feet, Maf), or 99 percent of the 30 year average (1981 – 2010). Conditions in the Upper Columbia (105 percent of normal measured at Arrow) and Kootenai basins (121 percent of normal measured at Libby) were wet while the Snake Basin was relatively dry (70 percent of normal measured at Lower Granite) resulting in the overall relatively average runoff. Similar to 2012, the upper Columbia and Kootenai River basins were hit in mid- to late June with a significant rainfall event, 2 to 4 inches in the Libby Basin and similar totals in the upper Columbia. Only minor modifications in actual hydro operations occurred during the year, which were due to significant powerhouse outages at Mica, where the project was drafted much deeper than required by the Flood Control Operating Plans (FCOP) and then surcharged to reduce spill during the latter part of the freshet. After a very wet October, and relatively average November and December, basin-wide precipitation was drier than normal during January through March. Conditions in the upper Columbia were somewhat wetter during the spring, but this was offset by drier than normal conditions on the Snake, which resulted in the average April-August runoff and an unregulated peak flow at The Dalles of only 14,200 m^3/s (cubic meters per second) (503 kcfs [thousand cubic feet per second]). Since 1960, 2013 ranks 31st wettest out of 54 years of record in total April-August runoff as measured at The Dalles. For the 1 August 2012 through 30 September 2013 reporting period, the Canadian Treaty Projects were operated according to the 2011-2012 and the 2012-2013 Detailed Operating Plans (DOPs), the 2003 FCOP, and several supplemental operating agreements described below. The Libby project was operated consistently with the Libby Coordination Agreement (LCA) including the Libby Operating Plan, United States (U.S.) requirements for power, and U.S. Fish and Wildlife Service's 2006 Biological Opinion (BiOp), as clarified, and NOAA Fisheries' 2010 Supplemental BiOp for operation and maintenance of the Federal Columbia River Power System.

Entity Agreements

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

- Columbia River Treaty Entity Agreement on the Assured Operating Plan (AOP) and Determination of Downstream Power Benefits for Operating Year 2017-2018, signed 12 April 2013.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2013 through 31 July 2014, signed 31 May 2013.
- Columbia River Treaty Short-Term Entity Agreement on Coordination of Libby Project Operations, signed 27 September 2013.

Columbia River Treaty Operating Committee Agreements

The Columbia River Treaty Operating Committee (CRTOC) completed one supplemental operating agreement during the reporting period:

- CRTOC Agreement on Operation of Treaty Storage for Nonpower Uses for 1 December 2012 through 31 July 2013, signed on 4 December 2012.

In addition to the Operating Committee agreement listed here, the Bonneville Power Administration (BPA) and British Columbia Hydro and Power Authority (B.C. Hydro) developed the following bilateral agreements:

- Agreement for use of Non-Treaty Storage Agreement (NTSA) Recallable Accounts for the period 2 March 2013 through 29 March 2014, agreed upon 5 March 2013.
- Agreement on use of Non-Treaty Storage for July and August 2013 for the period 1 July 2013 through 30 August 2013, agreed upon 3 July 2013.

System Operation

Under the 2012-2013 and 2013-2014 DOPs, Canadian storage was operated according to criteria from the 2012-2013 and 2013-2014 AOPs. During the 2012-2013 Operating Year, composite Canadian Treaty storage (Canadian storage) was operated close to the Treaty Storage Regulation (TSR) study composite storage, plus any operations implemented under the

Supplemental Operating Agreements or the LCA, except for some amounts of inadvertent draft or storage in all periods. Inadvertent draft or storage occurs routinely due to updated forecasts or differences between forecast and actual inflows.

Canadian storage began the operating year (1 August 2012) slightly below the DOP levels as determined in the TSR study. Canadian storage was drafted below TSR levels through September primarily due to differences in forecast and actual inflows. The Canadian Entity exercised their option to provisionally draft Arrow for only one of the two cycles under the LCA this year. The one and only cycle drafted Arrow by 68.5 cubic hectometer (hm^3 [55.5 kaf]) in October 2012. The LCA draft was not returned by the end of March 2013, and, by mutual agreement, the return was delayed until the week of 28 September through 4 October 2013.

For January until the end of June 2013, Canadian storage remained above the TSR-specified levels. This was due to operation under the Nonpower Uses Agreement that was implemented to achieve mutual fish benefits for the U.S. and Canada. Under provisions of this agreement, the U.S. Entity stored 1233 hm^3 (1 Maf) of flow augmentation water in January. The January forecast for the April-August water supply volume as measured at The Dalles was slightly above average 113.5 km^3 (92.03 Maf). This operation helped to modify and manage flows downstream of Hugh Keenleyside Dam for Canadian whitefish operation in January through March, and for Canadian trout spawning protection in April through June 2013.

The flow augmentation water was subsequently released starting the second week through the end of July 2013 to help meet U.S. salmon flow objectives. The water supply forecasts at The Dalles increased as the water year developed, from a January-July forecast of 110.6 km^3 (89.7 Maf) in March to 120.8 km^3 (97.9 Maf) in July.

During the spring freshet, B.C. Hydro sought and received approvals from the B.C. Comptroller of Water Rights (CWR) to surcharge by up to 0.3 m (1 ft) at Mica for power related reasons. Additionally, B.C. Hydro and BPA exercised storage operation under the Non-Treaty Shaping Agreement. Refer to Section III, Long Term Non-Treaty Storage, for more information on Non-Treaty operations. A total of approximately 0.70 km^3 (0.56 Maf) was stored in early July and released in August through early September. With this operation, the Columbia River flows at Birchbank (downstream of the Kootenay and Columbia confluence) peaked at

4,460 m^3/s (158 kcfs) on 5 July 2013, substantially below 2012 peak flow and below the flood damage threshold of 5,100 m^3/s (180 kcfs)[1].

For August through September 2013, Canadian storage targeted the TSR content. Due to differences in forecasted and actual inflows, there was minor inadvertent end-of-month storage across this time period.

Canadian Entitlement

For the period 1 August 2012 through 31 July 2013, the Canadian Entitlement amount, before deducting transmission losses, was 504.5 average megawatts (aMW) of energy, scheduled at rates up to 1321 megawatt (MW) capacity. From 1 August 2013 through 30 September 2014, the amount, before deducting transmission losses, was 505.5 aMW of energy, scheduled at rates up to 1336 MW capacity. The Canadian Entitlement obligation was determined by the 2012-2013 and 2013-2014 AOP and Determination of Downstream Power Benefits (DDPBs).

During the course of the 2012-2013 Operating Year, there were four curtailment events for Canadian Entitlement deliveries. These included a 43 megawatt hour (MWh) cut on 9 September 2012 due to a forest fire near Grand Coulee, a 48 MWh cut on 19 March 2013 due to transmission congestion within the BPA system, a 22 MWh cut on 25 April 2013 due to transmission line maintenance work and a 28 MWh cut on 28 September 2013 due to transmission congestion in the Puget Sound area of Washington State. All of the curtailed power was delivered later within the same month of curtailment, as per agreements between the Entities, with the exception of the 28 September 2013 cut, which was delivered on 1 October 2013 (and, as such, also complied with established Entities' scheduling guidelines). In February 2013, BPA retired the PSANI congestion management tool and installed new flow gates in the Puget Sound area to better manage localized transmission congestion.

Treaty Project Operation

At the beginning of the 2012-2013 Operating Year (1 August 2012), actual Canadian storage was at 19.06 km^3 (15.45 Maf) or 99.7 percent full. Canadian storage ended the operating year on 31 July 2013, at 18.93 km^3 (15.35 Maf) or 99.1 percent full.

[1] The flood damage threshold for the Columbia River between Castlegar and the U.S. border was revised to 5,100 m^3/s (180 kcfs) from 4670 m^3/s (165 kcfs) based on observations during the high-water runoff event of June-July 2012.

MICA (Kinbasket Reservoir)

The Kinbasket Reservoir reached its maximum 2012 elevation of 754.72 m (2476.1 ft) on 29 August 2012. This record high level was due primarily to very high rainfall in June-July that contributed to high basin inflows in combination with an extended outage for two Mica generators that lasted several months. During the fall and into the winter, the reservoir was drawn down to meet electrical demands, to prepare for the 2013 spring runoff and to manage extensive planned generating unit outages during the spring/summer 2013.

In preparation for the extensive Mica outage, B.C. Hydro released all of its Non-Treaty water by the end of the winter to enable additional draft from Kinbasket Reservoir prior to the outage, thereby minimizing spill risk at Mica during the extensive outage. Kinbasket Reservoir reached a minimum level for the year of 722.8 m (2371.4 ft) on 24 April 2013, about 0.8 m (2.7 ft) higher than the 2012 minimum level. Mica generation was limited to two units during the extended outage, which began in April and will continue until early November. The Mica powerplant output was reduced to below normal in April, and, except for brief periods, remained below normal during the entire outage. For five weeks from early June to mid-July, the Mica powerplant was completely isolated from the grid and discharged very little water.

The Basin runoff forecast hovered around normal from 1 January through 1 April. The actual January-July inflows at Mica were about 108 percent of normal. In July 2013, B.C. Hydro received permission from the B.C. CWR to surcharge Kinbasket Reservoir by up to 0.3 m (1 ft) for power related reasons. After mid-July, when the powerplant was reconnected to the grid, the refill of Kinbasket Reservoir was managed by running the two available generators at virtually maximum possible output. The Kinbasket Reservoir was in surcharge and spilled water during much of September.

KEENLEYSIDE (Arrow Lakes Reservoir)

The Arrow Lakes Reservoir had reached a maximum 2012 level of 440.5 m (1445.3 ft), or 0.4 m (1.3 ft) above full pool on 11 July 2012, just prior to the start of the 2012-2013 Operating Year. The minimum reservoir level during 2013 was 427.9 m (1404.0 ft) on 13 February. This was 0.4m (1.4 ft) higher than the previous year's minimum level. The maximum level reached by Arrow Lakes Reservoir in 2013 was on 3 July, at 440.0 m (1443.5 ft), 0.15 m (0.5 ft) below normal full pool.

The Arrow local runoff forecasts for 2013 hovered around normal for the 1 February to 1 May forecasts. The actual January-July 2013 local inflow volume to Arrow was about 103 percent of normal. Canadian Treaty Storage was in proportional draft from September 2012 to October 2012, but was otherwise on Operating Rule Curve (ORC) at other times during the 2012-2013 Operating Year.

To manage Arrow releases during the high inflow period of 2013, a Summer Shaping Agreement utilizing Non-Treaty storage was developed and signed by B.C. Hydro and BPA. The agreement was used by both parties to store Non-Treaty water in early July, with the stored water then released by early September. The Non-Treaty storage allowed the parties to limit flows to minimize flood risk downstream of Keenleyside Dam in Canada and to improve fish flows in the U.S. At about the same time, Arrow Reservoir was refilled to near full, fully utilizing its storage to minimize downstream flood risks.

These combined efforts resulted in a substantial reduction in the peak Columbia River flows. The Columbia River at Birchbank reached at maximum flow of 4,460 m^3/s (158 kcfs) on 5 July 2013, below the threshold flow for minor flooding impacts of 5,100 m^3/s (180 kcfs).

DUNCAN (Duncan Reservoir)

The Duncan Reservoir level peaked at 577.0 m (1892.9 ft) or 0.3 m (0.9 ft) above full pool on 23 July 2012, reaching the highest recorded level since the dam began operation in 1967. During August 2012, Duncan was operated to target a reservoir level of 575.5 m (1888 ft) on Labour Day. From September 2012 through April 2013, Duncan Reservoir was operated to supplement inflow into Kootenay Lake, to provide spawning and incubation flows for fish, and to meet Treaty flood control requirements. Duncan Reservoir was drafted to its minimum licensed level of 546.85 m (1794.2 ft) on 28 April 2013 – a fairly typical operation for Duncan. The reservoir releases were reduced to a minimum of 3 m^3/s (0.1 kcfs) beginning 24 May 2013 to initiate reservoir refill and to reduce the rate of rise for Kootenay Lake. Releases from Duncan Reservoir were then held at minimum until early July to manage the level of Kootenay Lake and maximize the value of the downstream energy generation. After the Kootenay Lake level began to recede, the Duncan Reservoir release was increased to manage its rate of refill. By 31 July 2013, the Duncan Reservoir level had reached 576.4 m (1891 ft), and the level

peaked a week later, on 7 August, at 576.64 m (1891.9 ft), or 0.04 m (0.1 ft) below the normal full pool level.

The flows in the Duncan River downstream of the Lardeau River (DRL) peaked this year at 386 m^3/s (13.6 kcfs) on 7 July 2013. Duncan Dam releases were adjusted in August to target a reservoir level of 575.5 m (1888.0 ft +/- 1 ft) on Labour Day (2 September 2013).

LIBBY (Koocanusa Reservoir)

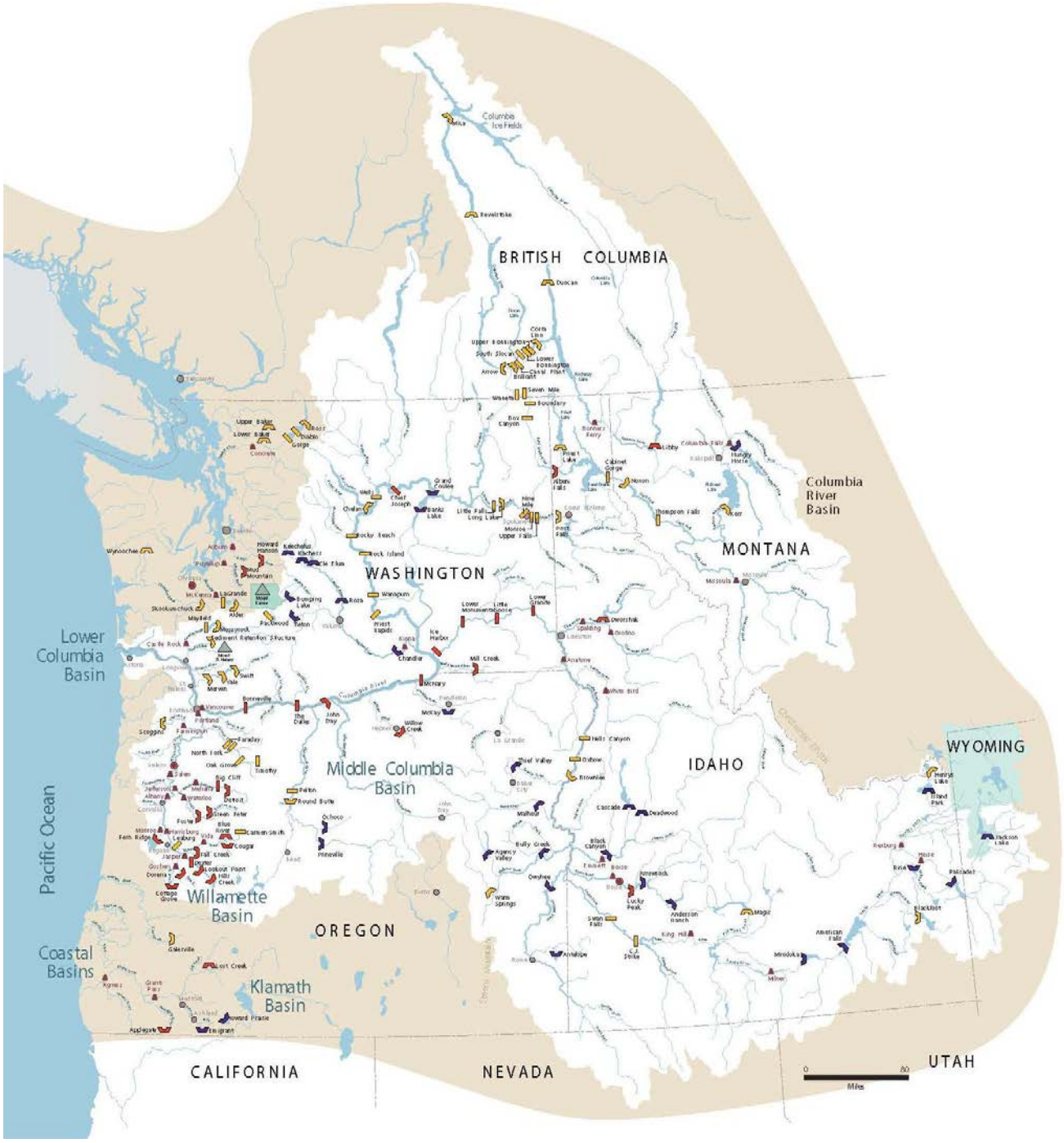
Lake Koocanusa ended July 2012 at elevation 749.20 m (2458.0 ft). From mid-July to the end of August 2012, the project was drafted slowly with outflows reduced gradually to 339.8 m^3/s (12 kcfs) by 24 August 2012 in preparation for the second and continuing season of the habitat restoration work in the Kootenai River, requiring lower flows in September of 226 m^3/s (8 kcfs) and October of 113 m^3/s (4 kcfs). The final April – August 2012 inflow volume to the project was 11.3 km^3 (9.2 Maf) or 156 percent of normal (1981 – 2010, 30 year flow record).

The December 2012 water supply forecast for April-August 2013 runoff came in at 7.6 km^3 (6.2 Maf) or 106 percent of average which set the end of December Flood Risk Management (FRM) elevation to 734.87 m (2411 ft). Subsequent forecasts ranged from 7.6 to 8.5 km^3 (6.2 to 6.9 Maf), with a May 1 forecast of 8.0 km^3 (6.5 Maf), or 111 percent of average. The start of refill was set for 1 May in 2013 and variable flow (VarQ) flood control releases were set at 510 m^3/s (18 kcfs) when inflows increased above the VarQ outflow. VarQ was held until 11 May when flows were increased to powerhouse capacity for the first of two sturgeon pulses, one of 7 days (11 May to 18 May) and one for 12 days (24 May to 5 June). June river flows were adjusted to approximately 453 m^3/s (16 kcfs) to target refill of the reservoir. From 18 June to 20 June, the Kootenai Basin was hit by a wraparound storm from the Gulf of Mexico which produced rain totals throughout the Basin of 2 to 4 inches in a 3-day span. As a result of this event, releases were increased above powerplant capacity from 22 June through 10 July – spilling a total of 0.25 km^3 (203 kaf). Inflows increased from 850 m^3/s (30 kcfs) to 2,520 m^3/s (89 kcfs) on 22 June and the reservoir ended June at elevation 748.62 m (2456.1 ft). The reservoir reached its peak elevation of 749.14 m (2457.8 ft) on 5 July 2013.

In order to accommodate a two unit outage beginning the third week of July and to try and get the reservoir to an elevation below 747.25 m (2451.6 ft) on 31 August, releases were held at

powerhouse capacity until 21 July and then were ramped down to 396 m^3/s (14 kcfs). The 396 m^3/s (14 kcfs) represented powerhouse capacity with only three units available and this flow was held until the end of the month. Lake Koocanusa was at an elevation of 748.74 m (2456.5 ft) at the end of July 2013 and 746.46 m (2449.0 ft) at the end of August 2013. The final April-August 2013 runoff totaled 8.9 km^3 (7.2 Maf) (121 percent of normal).

Columbia Basin Map



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Acronyms and Abbreviations

AER.....Actual Energy Regulation

aMW…….. .....Average Megawatts

AOP…….....Assured Operating Plan

B.C. Hydro.....British Columbia Hydro and Power Authority

BiOp.....Biological Opinion

BG ….....Brigadier General

BPA.....Bonneville Power Administration

cfs.....Cubic feet per second

COL…….. Colonel

CRC.....Critical Rule Curve

CRT.....Columbia River Treaty

CRTHC .....Columbia River Treaty Hydrometeorological Committee

CRTOC .....Columbia River Treaty Operating Committee

CWR .....B.C. Comptroller of Water Rights

DDPB.....Determination of Downstream Power Benefits

DOP.....Detailed Operating Plan

DRL.....Duncan River below the Lardeau confluence

FCOP.....Flood Control Operating Plans

FRM .....Flood Risk Management

ft .....feet

hm^3 .....Cubic hectometers

in .....inch

ICF .....Initial Controlled Flow

IJC.....International Joint Commission

kaf .....Thousand acre feet

kcfs.....Thousand cubic feet per second

KLBC……. Kootenay Lake Board of Control

km^3 .....Cubic kilometer (one billion cubic meters)

ksfd.....Thousand second-foot-days (= kcfs x days)

LCA.....Libby Coordination Agreement

m .....Meter

m^3/s .....Cubic meters per second

Maf.....Million acre-feet

MW .....Megawatt

MWh .....Megawatt hour

NOAA Fisheries.....NOAA Fisheries, formerly NMFS

NTS .....Non-Treaty Storage

NTSA .....Non-Treaty Storage Agreement

NWRFC .....Northwest River Forecast Center

ORC .....Operating Rule Curve

ORCLL .....Operating Rule Curve Lower Limits

PEB .....Permanent Engineering Board

PEBCOM .....PEB Engineering Committee

PNCA.....Pacific Northwest Coordination Agreement

POP ……Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage

TSR .....Treaty Storage Regulation

U.S. .....United States

USACE .....U.S. Army Corps of Engineers

VarQ.....Variable flow flood control

VRC .....Variable refill curves

VRCLL .....Variable Refill Curves Lower Limits

WUP.....Water Use Plan

WY .....Water Year

I – INTRODUCTION

This annual Columbia River Treaty Entity Report is for the Water Year (WY) 2013, 1 October 2012 through 30 September 2013, with additional information on the operation of Mica, Arrow, Duncan, and Libby reservoirs, as needed, to also cover the reservoir system operating year, 1 August 2012 through 31 July 2013. Also described are the power and flood control effects downstream in Canada and the United States (U.S.). This report is the 47th of a series of annual reports covering the period since the ratification of the Columbia River Treaty (Treaty, CRT) in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada were constructed as required under the CRT, and Libby Reservoir in the U.S. was constructed as provided for by the CRT. Treaty storage in Canada (Canadian storage) is operated for the primary purposes of flood control and increasing hydroelectric power generation in Canada and the U.S. In addition, the Treaty Entities (USACE, BPA, and B.C. Hydro) have arranged for a series of Treaty-related agreements to provide benefits beyond those for flood risk management and power, related to values such as fisheries, recreation, and others. In 1964, the Canadian and the U.S. governments each designated at least one Entity to formulate and carry out the operating arrangements necessary to implement the CRT.

The Canadian Entity for these purposes is British Columbia Hydro and Power Authority (B.C. Hydro). The Canadian Entity for the limited purpose of making arrangements for disposal of all or portions of the Canadian Entitlement within the U.S. is the government of the Province of British Columbia. The U.S. Entity is the Administrator & Chief Executive Officer of Bonneville Power Administration (BPA) and the Division Engineer of the Northwestern Division, U.S. Army Corps of Engineers (USACE).

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

1. Canada was to provide 19.12 cubic kilometers (km^3) (15.5 million acre feet [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 pre-determined to be generated in the U.S. resulting from operation of the Canadian storage.
4. The U.S. paid Canada a lump sum of $64.4 million (U.S.) for one-half of the present worth of expected future flood control benefits in the U.S. to September 2024, resulting from operation of the Canadian storage.
5. Under certain specified conditions, 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.) plus power losses for each of the first four requests for this "on-call" storage. No requests under this provision have been made to date.
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. This has not been exercised.
8. Differences arising under the Treaty that cannot be resolved by Canada and the U.S. 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, after which either Government has the option to terminate most sections of the Treaty if a minimum of 10 years advance notice has been given.

10. In the Canadian Entitlement Purchase Agreement of 13 August 1964, Canada sold its entitlement to downstream power benefits (Canadian Entitlement) to the Columbia Storage Power Exchange (a consortium of U.S. utilities) for 30 years beginning at Duncan Reservoir on 1 April 1968, Arrow Reservoir on 1 April 1969, and Mica Reservoir on 1 April 1973. That sale has now expired and all Canadian Entitlement has reverted to British Columbia provincial ownership and is delivered to the Canadian-U.S. border.
11. Canada and the U.S. each appointed Entities to implement Treaty provisions, as well as two members each to a joint 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 6 February 2013 in Vancouver.

The members of the two Entities at the end of the report period were:

UNITED STATES ENTITY

Mr. Elliot Mainzer, Chairman*
Acting Administrator &
Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

BG John S. Kem, Member**
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY

Mr. Chris O'Riley Chair
Executive Vice-President,
Generation
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

*Mr. Mainzer was appointed Acting Administrator on 15 July 2013. Mr. Drummond replaced Mr. Stephen Wright on 1 February 2013.

**COL(P) John Kem replaced Brigadier General (BG) Anthony Funkhouser on 15 July 2013. COL(P) John Kem was promoted to BG on 10 October 2013.

The Entities have designated alternates to act on behalf of the primaries in their absence, appointed in the U.S. by a Memorandum of Agreement between BPA and USACE, and in Canada by the B.C. Hydro Board of Directors. The BPA Administrator's alternate is the BPA Deputy Administrator and BG Kem's alternate is the Deputy Division Engineer. Mr. O'Riley does not have a named alternate, but the Canadian Entity has committed to making ad hoc delegations of alternate(s) if and when such action is required.

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 (the latter is no longer in effect);
3. Operate a hydrometeorological system;
4. Assist and cooperate with the PEB in the discharge of its functions;
5. Prepare and implement Flood Control Operating Plans (FCOPs) for the use of Canadian storage;
6. Prepare Assured Operating Plans (AOPs) for Canadian storage and determine the resulting downstream power benefits that Canada is entitled to receive; and
7. Prepare and implement Detailed Operating Plans (DOPs) that may produce results more advantageous to both countries than those that would arise from operation under AOPs.

Additionally, the CRT provides that the two governments, by exchange of diplomatic notes, may empower or charge the Entities with any other matter coming within the scope of the CRT, or appoint additional Entities for specific purposes. The Province of British Columbia is a Canadian Entity for the limited purpose of implementing the Disposal Agreement.

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.

Following are the appointed Coordinators and Secretaries:

UNITED STATES ENTITY COORDINATORS

Stephen R. Oliver
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

David J. Ponganis
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR

Renata Kurschner
Director,
Generation Resource Management
B.C. Hydro
Burnaby, British Columbia

UNITED STATES ENTITY SECRETARY

Scott R. Simms
Regional Coordination
Power and Operations Planning
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY SECRETARY

Douglas A. Robinson
Generation Resource Management
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 the following eight members:

UNITED STATES SECTION	**CANADIAN SECTION**
Richard M. Pendergrass, BPA, Alt. Chair	Kelvin Ketchum, B.C. Hydro, Chair
James D. Barton, USACE, Alt. Chair	Gillian Kong, B.C. Hydro
William D. Proctor, USACE	Herbert Louie, B.C. Hydro
Pamela Kingsbury, BPA	Alaa Abdalla, B.C. Hydro

The CRTOC met during the reporting period to exchange information, approve work plans, discuss issues, agree on operating plans, and brief the PEB and Permanent Engineering Board Engineering Committee (PEBCOM). There were six regular meetings held every other month alternating between Canada and the U.S., plus one meeting with the PEBCOM. During the period covered by this report, the CRTOC:

- Coordinated the operation of the CRT storage in accordance with the then-current hydroelectric operating plans and FCOP;
- Coordinated changes to procedures and reviewed scheduled delivery of the Canadian Entitlement according to the CRT and related agreements;
- Completed the 2017/18 AOP/Determination of Downstream Power Benefits (DDPB);
- Completed the 1 August 2013 through 31 July 2014 DOP;
- Completed one supplemental operating agreement for Canadian storage;
- Completed two bilateral agreements between B.C. Hydro and Bonneville Power Administration on the use of (1) use of Recallable Accounts March 2013 through March 2014 and (2) Non-Treaty Storage for July and August 2013;
- Implemented the Libby Coordination Agreement (LCA) including the August 2012 update to the Libby Operating Plan, which involved scheduling of Arrow provisional draft, and delivery of one average MW of power, and analysis and monitoring of Canadian power effects from VarQ flood control operation at Libby Reservoir;
- Briefed the PEBCOM on Entity activities, and completed the 2012 Entity Annual Report.

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

CRT Operating Committee at Grand Coulee Dam, July 2013. Pictured are (L to R), Scott Simms (Secretary), Rick Pendergrass (U.S. Alternate Chair), Doug Robinson (Secretary), Pam Kingsbury (member), Jim Barton (U.S. Alternate Chair), Gillian Kong (Member), Bill Proctor (member), Kelvin Ketchum (Canadian Chair). CRTOC members missing from the picture: Alaa Abdalla and Herbert Louie.

Columbia River Treaty Hydrometeorological Committee

The Columbia River Treaty Hydrometeorological Committee (CRTHC) was established in September 1968 by the Entities and is responsible for coordinating hydrometeorological data collection, data exchange and water supply forecasting for the CRT projects in accordance with the Treaty and otherwise assisting the Entities, as needed. The Committee consists of the following four members:

UNITED STATES SECTION

Ann McManamon, BPA Co-Chair
Peter Brooks, USACE Co-Chair

CANADIAN SECTION

Stephanie Smith, B.C. Hydro, Chair
Adam Gobena, B.C. Hydro, Member

The CRTHC met twice in the 2012-2013 Operating Year:

Meeting 71: 14 April 2013, B.C. Hydro

Meeting 72: 18 September 2013, BPA

The 2012 CRTHC Annual Report was completed in January 2013 and distributed at the annual PEB meeting.

Forecasting

The CRTHC continued to monitor and work with District staff on the proposed new Dworshak forecast procedure. It is anticipated that the procedure should be reviewed, approved, and accepted by the CRTOC in time for the 1 January 2014 official forecast.

The Northwest River Forecast Center (NWRFC) continues to produce water supply forecasts using the Ensemble Streamflow Prediction procedure. The CRTOC had tasked the CRTHC to monitor and evaluate the original recommendation of which specific forecasts to use for treaty purposes annually. The CRTHC has prepared a recommendation for the CRTOC with Ensemble Streamflow Prediction forecast issue dates that will be the official ones for use in the Treaty FCOP, the Actual Energy Regulation (AER), and the Treaty Storage Regulation (TSR). In the October 2013 CRTOC meeting, the CRTHC provided these recommendations for forecast dates (typically the 5th working day of the month) for the upcoming year. The CRTHC will continue to monitor and evaluate the range of Ensemble Streamflow Prediction forecast lead times to determine what best serves the needs of the Treaty.

The October 2012 precipitation in Canada was significantly above normal and caused the water supply forecast procedures for the Treaty projects to be artificially high. B.C. Hydro proposed an adjustment to the input variables to capture above normal precipitation while not unduly influencing the water supply forecasts. That adjustment remained in place through much of the season.

Above average precipitation in the first half of May 2013 required an adjustment to the coordination process for the second AER/TSR of the month. While normally the official forecasts would be used to distribute the remaining volume into June and July, in anticipation

of an increase in 1 June official forecasts, all three months (May, June and July) were coordinated separately as agreed upon during a CRTHC coordination phone call.

Data Exchange

The Corps' Columbia Basin Regional Water Management Water Control Data System implementation caused some trouble for some of its downstream users at BPA. To mitigate these problems, the Corps has instituted regular meetings with stakeholders to increase communication and reduce misunderstandings.

B.C. Hydro continues to improve the reliability and robustness of its new data system. They have instituted an IT Helpdesk with 24 hour coverage and have provided contact information to users in case of problems with the data feeds.

Stations

CRTHC is working on an updated listing of Treaty and Supporting Stations and will be re-instating letters to agencies which manage Treaty Monitoring Stations to remind them of the importance of the continued operation of these stations. Building on the initial format developed by B.C. Hydro, the USACE has begun populating the spreadsheet with appropriate stations in the U. S.

The Keystone Creek snow pillow installation proceeded this past year with installation occurring during August 2013. The site is transmitting data and has begun accumulating snow. Other sites were agreed upon by BPA and B.C. Hydro, and the permitting and approval processes continue for those sites.

A number of Montana snow courses were discontinued this year due to funding reductions at the Natural Resource Conservations Service. Several other key snow course early season (January and February) readings used by the U.S. Bureau of Reclamation for water supply forecasts at Hungry Horse Reservoir were not officially measured, and the Natural Resource Conservations Service provided estimates to the U.S. Bureau of Reclamation.

Permanent Engineering Board

Provisions for the establishment of the PEB and its duties and responsibilities are included in the CRT and related documents. The members of the PEB at present are:

UNITED STATES SECTION	**CANADIAN SECTION**
Stephen L. Stockton, Chair Washington, D.C.	Jonathan Will, Chair Ottawa, Ontario
Edward Sienkiewicz, Member Newberg, Oregon	Tim Newton, Member Vancouver, British Columbia
Dr. Robert A. Pietrowsky, Alternate Washington, D.C.	Glen Davidson, Alternate Victoria, British Columbia
George E. Bell, Alternate Portland, Oregon	Ivan Harvie, Alternate Calgary, Alberta

The following serve as Secretaries to the Board:

Jerry W. Webb, Secretary Washington, D.C.	Darcy Blais, Secretary Ottawa, Ontario

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 both governments if there is substantial deviation from the hydroelectric or FCOPs, 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; and
- Investigate and report on any other CRT related matters 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, CRTOC agreements, updates to hydrometeorological documents, personnel appointments, pertinent correspondence, and the annual Entity report to the PEB for their information and review. The annual joint meeting of the PEB and the Entities was held on 5-6 February 2013 in Vancouver, British Columbia. The Entities and the PEB met to discuss the current status of the 2014 CRT Review, the preparation and implementation of operating plans, the delivery of the Canadian Entitlement and other topics requested by the PEB. A key request from the 2013 PEB / Treaty Entities meeting was for the CRTOC to work toward a plan for resolving the issue of lost Canadian power revenue due to the U.S. adoption of variable flow (VarQ) flood control operating procedure at Libby Reservoir.

PEB Engineering Committee

The PEB has established the PEBCOM to assist in carrying out its duties. The PEBCOM met with the Operating Committee on 24 October 2012 in Portland, Oregon. The members of PEBCOM at the end of this report period were:

UNITED STATES SECTION

Jerry W. Webb, Chair
Washington, D.C.

Michael S. Cowan, Member
Lakewood, Colorado

Kamau B. Sadiki, Member
Washington, D.C.

Pat McGrane, Member
Boise, Idaho

CANADIAN SECTION

Ivan Harvie, Interim Chair
Calgary, Alberta

Darcy Blais, Member
Ottawa, Ontario

K.T. Shum, Member
Victoria, British Columbia

International Joint Commission

The IJC was created under the Boundary Waters Treaty of 1909 between Great Britain (on behalf of 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 current IJC membership includes U.S. Section Chair Ms. Lana Pollack, Canadian Section Chair is Joseph Comuzzi, U.S. members Mr. Rich Moy and Dereth Glance, and Canadian members are Gordon Walker and Benoit Bouchard. The IJC writes Orders to implement decisions relating to boundary waters and also appoints local Boards of Control to insure compliance with IJC Orders and to keep the IJC informed. There are three sets of such orders and boards west of the Continental Divide. These are the International Columbia River Board of Control, the International Osoyoos Lake Board of Control, and the 1938 Order on Kootenay Lake and the International Kootenay Lake Board of Control (KLBC).

An ongoing issue had been a discussion of Libby and Duncan dams operating to the IJC rule curve that was set for Kootenay Lake downstream (Corra Linn Dam operated by Fortis BC). The rule curve in question was set on 11 November 1938, when the IJC granted an Order of Approval to operate Corra Linn Dam to store additional water in Kootenay Lake and to excavate the outlet of the lake at Grohman Narrows. The 1938 Order specified that the project be operated subject to a number of conditions and established the KLBC to supervise the construction and subsequent operation of the project (Corra Linn). With the signing of the CRT in 1964 and the construction of Libby Dam, as the Kootenai River is a boundary river, Libby operations would be subject to the IJC and the International Boundary Water Treaty of 1909. This was assumed in the CRT, as Article XII, 6 which states that:

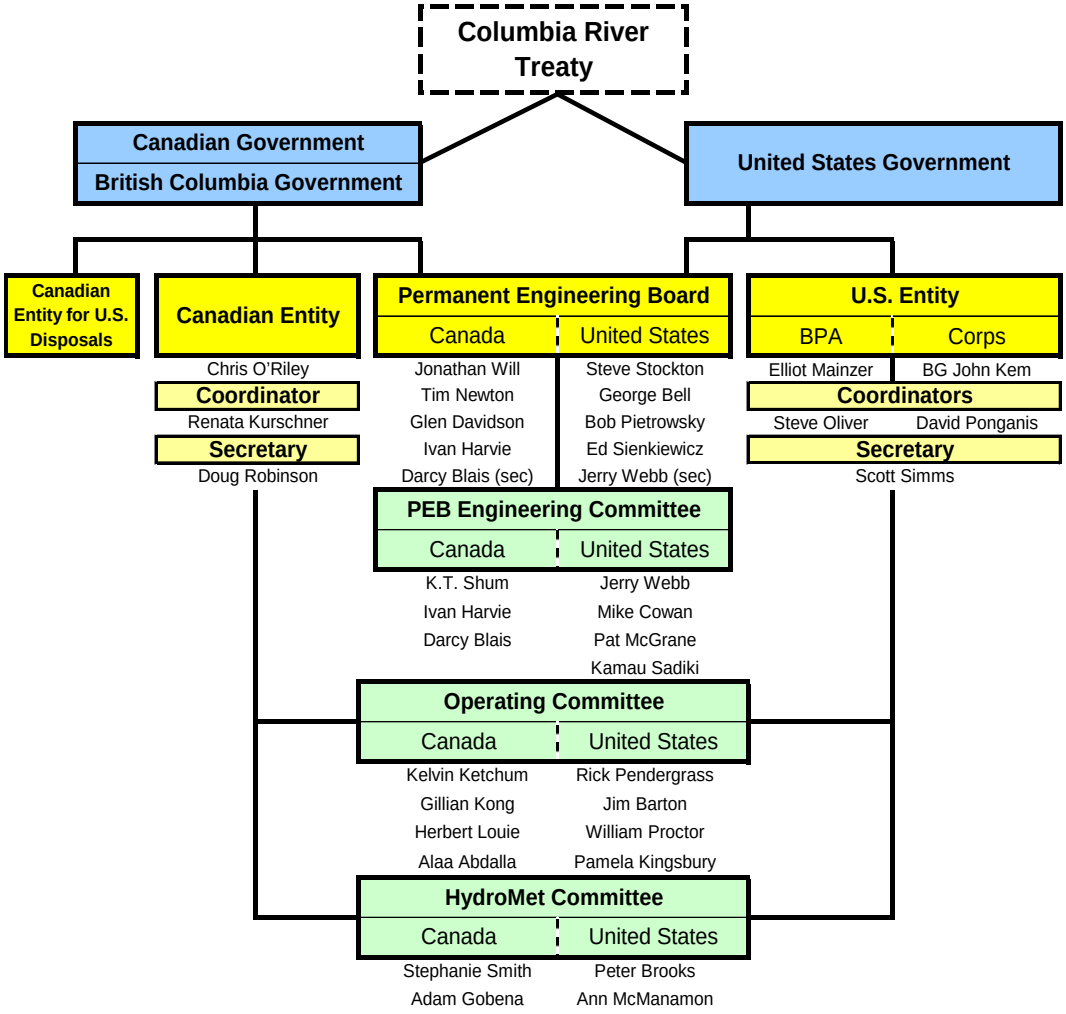
> "*The operation of the storage* [Libby] *by the United States of America shall be consistent with any order of approval which may be in force from time to time relating to the levels of Kootenay Lake made by the International Joint Commission under the Boundary Waters Treaty, 1909.*"

In light of recent high-water events on the Kootenay system, the entities began to re-evaluate what is meant to "shall be consistent with" as mentioned in Article XII, 6 of the Treaty. The Order on Kootenay Lake was written in 1938, and, therefore, the Order itself does not place constraints on Libby and Duncan dam operation. Rather, the only "constraint" would be the interpretation of CRT Article XII, 6. The CRTOC recently (2012) completed a Flood Risk Management (FRM) study, "Evaluation of Libby Dam Flood Risk Management Operations on Kootenay Lake," that evaluated the benefits of fully drawing down the reservoirs to complete flood drafts at both projects. In summary, the CRTOC recommended that Libby and Duncan dams modify their operations to allow the projects to fully draft for flood control in the winter and early spring, regardless of whether or not the Kootenay Lake level is above the rule curve outlined in the 1938 IJC Order for Kootenay Lake. This would provide better flood risk benefits for Kootenay Lake and other downstream locations during the spring freshet for both countries. This recommendation is based on the interpretation that, because there is not a specific IJC Order directed to Libby or Duncan at this time, the projects are therefore not constrained by IJC Orders directed to other projects[2]. In most years, there is no conflict between the full flood control draft of upstream Treaty reservoirs and maintaining Kootenay Lake levels below the IJC Order reference level. However, in those years of potential conflict, typically when the water supply forecast rises rapidly during the spring, the Libby and Duncan reservoirs will draft to their required FRM levels, even if this causes the level of Kootenay Lake to exceed the IJC reference level. The report was initially presented to the KLBC at the 22 September 2011 meeting; a revised version of the report was presented at the 26 September 2012 meeting and the final report addressing KLBC comments was submitted on 7 December 2012. As of the KLBC meeting of 12 September 2013, the issue is considered closed.

[2] This interpretation was also presented and discussed with the KLBC in meetings held during 22 September 2011. Previously, the 2008 annual report by the KLBC confirmed that neither Duncan nor Libby Dam operations are constrained by the Kootenay Lake (Corra Linn Reservoir) maximum lake elevations from the 1938 order. The 2008 Board report states "With regard to the upstream dams, the Board has concluded that it has no authority to direct their operations, whether through the 1938 Order or the Columbia River Treaty. The Commission supported this conclusion stating that the 1938 Order is directed solely to the Applicant, and operation of the upstream dams is a matter for the two federal governments to determine." (KLBC Meeting Minutes, 22 September 2011).

Columbia River Treaty Organization

Organization Chart for the Columbia River Treaty



Notes:

1) The Entities and the PEB are creations of the Treaty, and all report directly to their respective governments.

2) The Operating Committee and the HydroMet Committee report to the Entities; the PEBCOM reports to the PEB.

3) CRT XIV2(f): The Entities are tasked with "*assisting and cooperating with the PEB*".

4) CRT XV2(c): Similarly, the PEB is directed to *"assist in reconciling differences concerning technical or operational matters that may arise between the entities"*.

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 under 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 assured hydroelectric operating plans for Canadian storage for the 6th succeeding year of operation.

Article XIV.2.k of the CRT provides that a DOP be developed that may produce results more advantageous to both countries 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," (also referred to as the "POP") signed December 2003 (as amended), together with the "Columbia River Treaty Flood Control Operating Plan" dated May 2003 (as revised), 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 are for the 2012-2013 Operating Year from 1 August 2012 through 31 July 2013. The operation of Canadian storage was determined by the 2012-2013 DOP and supplemental operating agreements. The DOP required a semi-monthly TSR study to determine end-of-month storage obligations (prior to any adjustments associated with supplemental operating agreements). The TSR included all operating criteria from, and was based on, the Step I Joint Optimum Power Hydroregulation Study from the 2012-2013 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period from August 2012 through September 2013.

Assured Operating Plans

During the reporting period, the Entities completed the 2017-2018 AOP. An Entity agreement approving the 2017-2018 AOP was executed on 12 April 2013. The 2017-2018 AOP studies are based on procedures defined in the CRT, Annexes, and Protocol and, except as noted in the AOP/DDPB document, the 2003 POP document and agreed appendices. However, only the first of the three streamline procedures (forecasting loads and resources) defined in POP Appendix 6 was used, since the Entities conducted a full set of Steps I, II, and III U.S. Optimum and Joint Optimum system regulation studies.

The 2017-2018 AOP establishes Operating Rule Curves (ORCs), Critical Rule Curves (CRCs) Mica and 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 Rule Curves), Variable Refill Curves (VRC), Operating Rule Curve Lower Limits (ORCLL), and Variable Refill Curves Lower Limits (VRCLL), as described in the 2003 POP. They provide guidelines for draft and refill under a wide range of possible water conditions. The Flood Control Rule Curves conform to the 2003 FCOP and are used to define maximum reservoir levels for the operation of Canadian storage. The 2017-2018 AOP uses the 5.03/4.44 km^3 (4.08/3.6 Maf) Mica/Arrow flood control allocation. The CRCs are used to apportion draft below the ORCs when the TSR determines additional draft is needed to meet the Coordinated System firm energy load carrying capability.

During the reporting period, the Entities initiated the 2018-2019 AOP studies which include all three of the streamline procedures defined in POP Appendix 6, and completed the studies along with the AOP/DDPB document in the fall of 2013.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits (DDPB) resulting from Canadian storage operation is made in conjunction with the AOP according to procedures defined in the CRT, Annexes, and Protocol, and the 2003 POP agreement (except for modifications noted in the AOP/DDPB documents). The 2017-2018 DDPB studies included full Steps II and III system regulation studies as described in Section 3.3 of POP.

The total downstream power benefits as a result of the operation of Canadian storage for the 2017-2018 Operating Year were determined to be 2608.2 MW of dependable capacity, and 950.1 average annual MW of usable energy. Therefore, the Canadian Entitlement to downstream power benefits is 1304.1 MW of capacity, which is a 29.1 MW decrease from the 2016-2017 DDPB. This decrease is caused by a slight increase in the critical period load factor as well as a greater reduction in the Step II critical period generation relative to the Step III critical period generation. The Canadian Energy Entitlement is 475.0 average megawatts (aMW) of average annual energy, which is a 9.0 aMW decrease from the 2016-2017 DDPB. This decrease is caused mainly by a combination of changes in the shape of the Thermal Displacement Market, as well as the Steps II and III loads.

Canadian Entitlement for the Operating Year

For the period 1 August 2012 through 31 July 2013, the Canadian Entitlement amount, before deducting transmission losses, was 504.5 aMW of energy, scheduled at rates up to 1321 MW capacity. From 1 August 2013 through 30 September 2014, the amount, before deducting transmission losses, was 505.5 aMW of energy, scheduled at rates up to 1336 MW capacity. The Canadian Entitlement obligation was determined by the 2012-2013 and 2013-2014 AOP/DDPBs.

During the course of the 2012-2013 Operating Year, there were four curtailment events for Canadian Entitlement deliveries. These included a 43 megawatt hour (MWh) cut on 9 September 2012 due to a forest fire near Grand Coulee, a 48 MWh cut on 19 March 2013 due to transmission congestion within the BPA system, a 22 MWh cut on 25 April 2013 due to transmission line maintenance work, and a 28 MWh cut on 28 September 2013 due to

transmission congestion in the Puget Sound area of Washington State. All of the curtailed power was delivered later within the same month of curtailment, as per agreements between the Entities, with the exception of the 28 September 2013 cut, which was delivered on 1 October 2013 (and, as such, also complied with established Entities' scheduling guidelines). The U.S. Entity also invited BPA's Susan Millar, a transmission system expert, to explain to the CRTOC the operating circumstances and grid congestion events that contributed to the unplanned, pro-rata cuts to firm transmission schedules in the Northwest in the spring months of 2012, which included reductions to the Canadian Entitlements deliveries. This occurred at the 7 May 2013 meeting. In February 2013, BPA retired the PSANI congestion management tool and installed new flow gates in the Puget Sound area to better manage localized transmission congestion.

Detailed Operating Plans

During the period covered by this report, the CRTOC used the DOP for 1 August 2012 through 31 July 2013, dated June 2012, and the DOP for 1 August 2013 through 31 July 2014, dated May 2013, to guide Canadian storage operations. These DOPs established criteria for determining the ORCs, proportional draft points, and include other operating criteria for use in actual operations. The 2012-2013 and 2013-2014 DOPs were based respectively on the 2012-2013 AOP and 2013-2014 AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects. The 2012-2013 and 2013-2014 AOPs included a flood control allocation of 4.43 km^3 (3.6 Maf) in Arrow and 5.03 km^3 (4.08 Maf) in Mica. The 2012-2013 DOP and 2013-2014 DOP operating criteria were used to develop the TSR studies for implementation of Canadian storage operations. The changes from the AOP were mainly updates to flood control upper rule curves, hydro-independent data, incorporation of updated forecast errors and distribution factors, plant data, Grand Coulee pumping estimates, and 2010 level modified flows.

The TSR studies were updated twice monthly throughout the reporting period for current inflow forecasts, flood control curves and VRCs, and actual unregulated inflows for the previous month. The TSR and supplemental operating agreements defined the end-of-month draft rights for Canadian storage. The VRCs and flood control requirements, subsequent to

1 January 2013, were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby Reservoir for the 2012-2013 Operating Year are shown in Tables 2 through 5. The calculation in Table 5 for Libby's VRCs was used in the TSR study only and is not used in actual operations. The CRTOC directed the regulation of the Canadian storage on a weekly basis throughout the year, in accordance with the applicable DOPs, the LCA, and supplemental operating agreements.

Libby Coordination Agreement

During the period covered by this report, the 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 2012-2013 Operating Year. Provisional draft operations under the LCA are discussed in Section VI. The most recent Libby Operating Plan is dated 19 July 2013.

Entity Agreements

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

Date Signed by Entities	Description of Agreement
12 April 2013	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2017-2018.
31 May 2013	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2013 through 31 July 2014.
27 September 2013	Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations

Columbia River Treaty Operating Committee Agreements

During the period covered by this report, the CRTOC approved the following joint U.S.-Canadian storage agreement:

Date Signed	Description	Authority
4 December 2012	Columbia River Treaty Entity Agreement on Operation of Treaty Storage for Nonpower Uses for 1 December 2012 through 31 July 2013	Detailed Operating Plan 1 August 2012 through 31 July 2013, dated 8 June 2012

In addition to the Operating Committee agreement listed above, BPA and B.C. Hydro developed the following bilateral agreements:

- Agreement for use of Non-Treaty Storage Agreement (NTSA) Recallable Accounts for the period 2 March 2013 through 29 March 2014, agreed upon 5 March 2013.
- Agreement on use of Non-Treaty Storage for July and August 2013 for the period 1 July 2013 through 30 August 2013, agreed upon 3 July 2013.

Long Term Non-Treaty Storage Agreement

The Long Term NTSA, executed in April 2012 through September 2024, was utilized by BPA and B.C. Hydro to store water in high runoff periods in the summer of 2012. Water stored during the spring/summer was released from early August through mid-September 2012.

An agreement between BPA and B.C. Hydro to utilize additional non-Treaty space available at Arrow allowed shaping of Arrow outflows during the high flows in July and August 2012, for the mutual benefit of both B.C. Hydro and downstream U.S. systems. The NTSA was also used to shape high Arrow outflows in early July 2013, into August and early September 2013.

In accordance with the 10 April 2012 Entity agreement, which approved the 2012 NTSA contract between BPA and B.C. Hydro, the CRTOC monitored the storage operations made

under the Agreement throughout the operating year to ensure they did not adversely impact operation of CRT storage required by the DOPs.

IV - WEATHER AND STREAMFLOW

After two straight years of La Niña Pacific Ocean conditions heavily influencing the region's weather, equatorial sea surface temperatures moderated, hovering around the warm side of normal for most of the year. Thus, El Nino Southern Oscillation did not play a significant role in the region's weather. Precipitation and temperatures took a turn away from the previous two wet and cool operating years toward the warmer and drier side of normal. Although the Madden-Julian Oscillation did exert some influence on jet stream patterns at times, for the most part, it was not a significant player in regional weather. August of 2012 through July of 2013 saw basin-wide temperature departures significantly above normal (1.7 ºF/0.8 ºC). Precipitation for WY 2013 was about 90 percent of normal, based on the (1971-2000) period for the Basin as a whole.

August 2012 brought very dry weather to the Columbia River Basin, not unlike that of August 2011. A developing drought signal in the southern Snake River Basin began to spread northward and the drier weather led to steadily decreasing flows throughout the month. By the end of August, and for all of September, natural streamflows had sunk to below long-term averages. The drier weather was accompanied by an extended period of warm weather, punctuated by modest heat waves in mid-August, and again in early September.

The first ten days of October 2012 were very dry for the Columbia River Basin. This was a continuation of the mild, extremely dry weather pattern which dominated July through September. The remainder of the month of October took a dramatic shift to very wet conditions (see Figure 1) as a subtropical moisture tap unleashed heavy rain and higher elevation snow for much of the region. The moisture tap continued for much of the remainder of the month, and, despite the slow start, by the end of the month the region had received nearly double its normal precipitation – concentrated over the northwest half of the Basin.

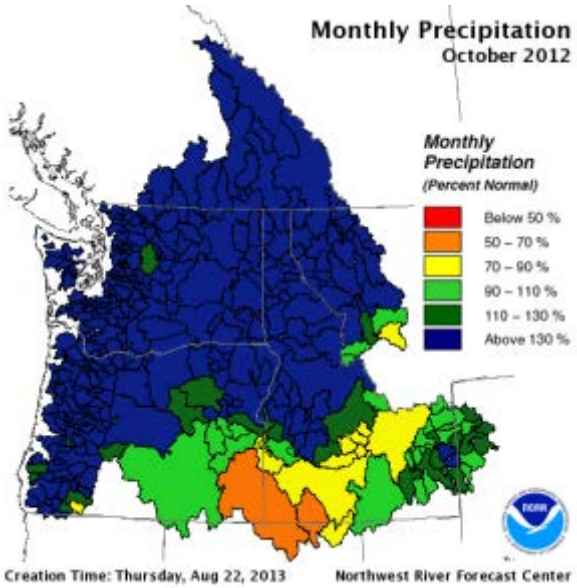


Figure 1. Map of Basin Precipitation October 2012

November-December 2012 marked a two-month stretch of slightly above normal precipitation for the Basin (100 to 120 percent) with significantly above normal temperatures. Unlike previous years, November 2012 brought a progressive weather pattern, with repeating pattern of relatively stormy periods and dry periods. During December, the jet stream sagged south, focusing over the southern half of the Basin. British Columbia was relatively dry, while the brunt of the storms affected the southern tier.

The New Year seemed to bring a shift in the overall weather pattern towards drier conditions (see Figure 2). During January, high latitude blocking lead to significant stretches of relatively dry weather. Snowpack percentages for the Basin dropped 16 percent during the month of January (from 109 percent to 93 percent). Strong high pressure aloft capped cold air trapped in many of the valleys, leading to strong temperature inversions. Meanwhile, the higher terrain enjoyed many relatively warm, sunny days. Temperatures across the Basin were split on a north/south line with temperatures in the northern portion of the Basin being significantly warmer than average and the southern tier being significantly below average.

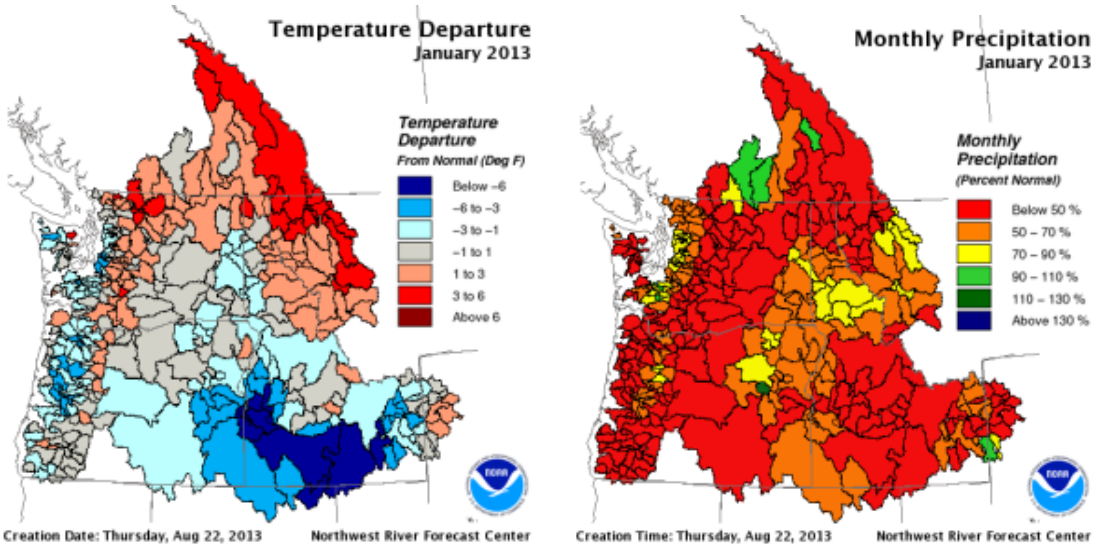


Figure 2. Map of Basin Temperature Departure and Precipitation January 2013

The relatively dry weather pattern continued through most of February, although the storm-blocking high pressure ridge began breaking down toward the end of the month as storms began hitting the Canadian portion of the Basin. Precipitation amounts above The Dalles for January and February were a mere 66 percent and 55 percent of normal respectively -- substantial shortfalls for two of the wettest months of the water year. The forecasted January-July runoff dropped below 90 MAF for over a month.

Although temperatures bounced around month-to-month during the spring of 2013, the precipitation pattern was relatively stable. During these months, the jet stream and corresponding storm track favored northern or northwest portions of the Columbia River Basin. In response, the drought over the central Great Basin, which had moved northward into the Snake River Basin during the previous summer and fall, began another expansion northward. Precipitation in the upper Columbia Basin (as measured above Grand Coulee) during the spring was slightly above normal in contrast to precipitation in the Snake River Basin (measured above Ice Harbor), which was a significantly below normal.

Temperatures during the spring were well above normal for both March and May, but below normal for April. There was a significant early season warm-up during the end of March into early April that led to the first significant surge of the runoff. The peak runoff occurred during mid-May this year in response to a region-wide heat wave. This peak was a full month ahead of the normal peak which typically occurs in June. Areas west of the

Cascades broke high temperature records during this period. The peak of the runoff during the previous two years had been precipitation-driven, but this returned to the more traditional temperature-driven snowmelt runoff pattern in 2013.

June experienced an upturn in precipitation across the Basin with southern British Columbia, eastern Washington and the panhandle of Idaho having significantly above average precipitation. However, the rest of the Basin saw only average or significantly below average precipitation. As temperatures cooled and the snowpack receded, runoff slowly receded.

Late June to early July saw a very strong high pressure ridge develop over the West. This was the first heat wave in several years to impact the Pacific Northwest, Desert Southwest, and California at the same time. There was a significant heat spell 30 June to 2 July. Following the brief snowmelt response from this heat wave, the majority of Basin runoff was depleted as flows once again dipped well below normal by mid-July.

Although summer was a bit slow getting started, that all changed for July and August as a persistent warm, dry pattern took hold over the region. As high pressure dominated, precipitation was generally shunted to the north and south around the fringes of the region.

During July and early August, only about a quarter of the normal precipitation fell over the Columbia River Basin, leading to increased drought concerns. In addition, temperatures were abnormally hot, especially east of the Cascades where the marine influence was minimal. During August, dry lightning activity picked up over the Basin, combining with tinder dry fuels to lead to serious wildfire outbreaks -- the most significant fire activity in several years.

September began as a continuation of August with warm and dry conditions across much of the Basin. About half way through the month, however, conditions changed drastically and a series of storms brought consistently cooler and wetter weather basin-wide. A significant number of stations reported new monthly record precipitation for September.

Columbia Basin Weather

Location	Temperature	Precipitation	Precipitation	Precipitation
	*Pacific Northwest	Columbia River above Coulee	Snake River above Ice Harbor	Columbia River above The Dalles
	departure from 1981-2010 average (ºC / ºF)	percent of the 1981-2010 average (%)	percent of the 1981-2010 average (%)	percent of the 1981-2010 average (%)
August 2012	+1.5 / +2.7	34	18	51
September 2012	+ 1.6 /+2.8	26	29	23
October 2012	-0.1 / -0.1	194	130	164
November 2012	+2.0 / +3.6	117	97	102
December 2012	+1.4 / +2.6	84	108	94
January 2013	-0.2 / -0.4	51	52	49
February 2013	+1.0 / +1.9	61	47	50
March 2013	+0.9 / +1.5	102	54	72
April 2013	-1.3 / - 1.3	114	64	87
May 2013	+0.9 / +1.5	98	55	82
June 2013	+0.7 / +1.3	124	61	98
July 2013	+2.3 / +4.3	20	31	21
August 2013	+1.7 / +3.1	83	51	75
September 2013	+1.2 / + 2.2	187	248	225

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2012 through 30 September 2013 are shown on Charts 5 through 7. Libby hydrographs are shown in Chart 8. Observed flows and unregulated flows (computed using the USACE Streamflow Synthesis and Reservoir Regulation SSARR model) for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 9 through 12, respectively. A plot of the flows that would occur at The Dalles if regulated only by the four Treaty reservoirs is provided in Chart 13 along with the observed and unregulated flows at The Dalles for comparison.

The peak-unregulated discharge for the Columbia River at The Dalles was 14,200 m^3/s (503 kcfs) on 15 May 2013, based on the USACE SSARR model run. The average monthly

unregulated values shown in the table in the following section are from the NWRFC. The values from NWRFC do not reflect the effects of natural lakes, whereas the USACE SSARR model does. Natural lake effects cause attenuation and dampening of flows; thus, the SSARR model simulations provide lower flows than the NWRFC tabulations. As per the table below, the unregulated August 2012-July 2013 streamflow at The Dalles was average (100 percent of 1981-2010 average) and approximately 18 percent lower than last year's flow. The total runoff volume at The Dalles during this same time period was 162 km^3 (131 Maf) based on NWRFC, and is also 100 percent of the average.

Columbia River Unregulated Streamflow

(Source of unregulated flow = National Weather Service Runoff Processor)

	Columbia River at Grand Coulee			**Columbia River at The Dalles**		
	Unregulated Flow		**Percent of**	**Unregulated Flow**		**Percent of**
Time Period	**cfs**	**m^3/s**	**Average**	**cfs**	**m^3/s**	**Average**
Aug-12	111,177	3,148	119	148,827	4,214	119
Sep-12	49,341	1,397	88	79,927	2,263	92
Oct-12	45,684	1,294	101	77,463	2,194	94
Nov-12	67,340	1,907	138	119,252	3,377	126
Dec-12	62,224	1,762	156	122,659	3,473	134
Jan-13	37,617	1,065	94	85,708	2,427	88
Feb-13	36,509	1,034	86	86,699	2,455	78
Mar-13	62,647	1,774	104	125,733	3,560	85
Apr-13	129,386	3,664	108	228,741	6,477	99
May-13	301,882	8,548	120	458,044	12,970	111
Jun-13	310,903	8,804	106	407,535	11,540	93
Jul-13	174,995	4,955	98	222,744	6,307	94
Aug-13	89,774	2,542	96	119,227	3,376	95
Sep-13	68,752	1,947	122	98,985	2,803	114

Seasonal Runoff Forecasts and Volumes

April-August 2013 runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin (Data source = North West River Forecast Center or NWRFC):

2013 Basin Runoff Volumes (April-August)

Location	Volume in km^3	Volume in Maf	1981-2010 Average in Percent
Libby Reservoir Inflow	8.85	7.17	121%
Duncan Reservoir Inflow	2.68	2.17	108%
Mica Reservoir Inflow	14.40	11.67	106%
Arrow Reservoir Inflow	28.34	22.98	105%
Columbia River at Birchbank	52.73	42.75	110%
Grand Coulee Reservoir Inflow	75.29	61.04	108%
Snake River at Lower Granite	18.15	14.72	70%
Columbia River at The Dalles	107.38	87.05	99%

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2013 for a large number of locations in the Columbia River Basin and updated at the beginning of each month from December to July as the season advanced. Table 1 and Table 1M list the April through August inflow volume forecasts for Mica, Arrow, Duncan, and Libby projects as well as The Dalles. The actual runoff volume for these five locations is also given in Tables 1 and 1M. The forecasts for Mica, Arrow, and Duncan inflow were prepared by B.C. Hydro. The forecasts for the lower Columbia River inflows were prepared by the National Weather Service's NWRFC. The Libby inflow forecast is prepared by the USACE, Seattle District.

The official April 2013 forecast of January through July runoff for the Columbia River above The Dalles was 112.4 km^3 (91.1 Maf) and the actual observed runoff (NWRFC) came in higher at 120.5 km^3 (97.7 Maf). The following tabulations summarize the monthly forecasts since 1981 of the January-July runoff for the Columbia River above The Dalles compared with the actual runoff volume in km^3 and Maf. The average January-July runoff volume for the period of 1981-2010 (NWRFC) is 125.1 km^3 (101.4 Maf).

Historic Seasonal Runoff Forecasts and Volumes (km^3)

The Dalles, OR Volume Runoff Forecasts in km^3 (Jan-Jul)							
Year	Jan	Feb	Mar	Apr	May	Jun	Actual
1981	130.7	104.2	104.2	101.0	102.6	118.3	127.5
1982	135.7	148.0	155.4	160.4	161.6	157.9	160.2
1983	135.7	133.2	139.4	149.3	149.3	146.8	146.4
1984	139.4	127.0	120.4	125.8	132.0	140.6	146.9
1985	161.6	134.4	129.5	121.6	121.6	123.3	108.2
1986	119.4	115.1	127.0	130.7	133.2	133.2	133.6
1987	109.7	101.0	96.2	98.7	94.6	93.5	94.4
1988	97.7	92.3	89.7	91.3	93.9	92.5	90.9
1989	124.6	125.8	116.2	122.7	121.6	119.5	111.8
1990	106.7	124.6	128.3	118.4	118.4	122.7	123.0
1991	143.1	135.7	132.0	130.7	130.7	128.3	132.1
1992	114.2	109.9	103.0	87.8	87.8	83.6	86.8
1993	114.2	106.7	95.3	94.5	88.7	106.2	108.5
1994	98.3	94.1	96.3	90.3	93.1	94.2	92.5
1995	124.7	122.9	116.3	122.9	122.9	120.8	128.3
1996	143.1	150.5	160.4	155.4	165.3	173.9	171.8
1997	170.2	178.9	175.2	183.8	188.7	196.1	196.1
1998	106.6	117.4	113.1	112.0	109.9	124.6	128.3
1999	143.1	148.0	160.4	157.9	153.0	151.7	153.1
2000	129.5	130.7	129.5	129.5	129.5	125.8	120.9
2001	99.2	81.9	72.3	69.2	69.7	68.5	71.8
2002	123.3	125.8	120.0	118.9	121.1	123.3	128.0
2003	99.3	93.3	92.4	105.2	111.3	110.1	108.2
2004	127.0	123.3	114.6	103.9	98.1	105.0	102.3
2005	105.6	101.6	87.2	91.0	92.1	98.4	100.3
2006	125.0	137.0	132.0	132.0	136.0	137.0	141.0
2007	129.5	124.6	123.3	123.3	122.2	118.9	118.1
2008	125.8	127.0	127.0	124.6	120.0	121.1	122.4
2009	116.8	114.6	106.3	113.5	112.4	113.5	111.3
2010	109.2	97.7	88.6	86.0	87.5	91.3	104.5
2011	128.3	135.7	134.4	144.3	157.9	173.9	169.0
2012	106.1	112.6	121.9	139.2	148.1	145.3	159.7
2013	126.4	113.5	110.7	112.4	114.0	115.8	120.5
Minimum	97.7	81.9	72.3	69.2	69.7	68.5	71.8
Median	124.7	123.3	120.0	121.6	121.1	121.1	122.4
Maximum	170.2	178.9	175.2	183.8	188.7	196.1	196.1

Historic Seasonal Runoff Forecasts and Volumes (Maf)

The Dalles, OR Volume Runoff Forecasts in Maf (Jan-Jul)							
Year	Jan	Feb	Mar	Apr	May	Jun	Actual
1981	106.0	84.5	84.5	81.9	83.2	95.9	103.4
1982	110.0	120.0	126.0	130.0	131.0	128.0	129.9
1983	110.0	108.0	113.0	121.0	121.0	119.0	118.7
1984	113.0	103.0	97.6	102.0	107.0	114.0	119.1
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3
1987	88.9	81.9	78.0	80.0	76.7	75.8	76.5
1988	79.2	74.8	72.7	74.0	76.1	75.0	73.7
1989	101.0	102.0	94.2	99.5	98.6	96.9	90.6
1990	86.5	101.0	104.0	96.0	96.0	99.5	99.7
1991	116.0	110.0	107.0	106.0	106.0	104.0	107.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4
1993	92.6	86.5	77.3	76.6	71.9	86.1	88.0
1994	79.7	76.3	78.1	73.2	75.5	76.4	75.0
1995	101.1	99.6	94.3	99.6	99.6	97.9	104.0
1996	116.0	122.0	130.0	126.0	134.0	141.0	139.3
1997	138.0	145.0	142.0	149.0	153.0	159.0	159.0
1998	86.4	95.2	91.7	90.8	89.1	101.0	104.0
1999	116.0	120.0	130.0	128.0	124.0	123.0	124.1
2000	105.0	106.0	105.0	105.0	105.0	102.0	98.0
2001	80.4	66.4	58.6	56.1	56.5	55.5	58.2
2002	100.0	102.0	97.3	96.4	98.2	100.0	103.8
2003	80.5	75.6	74.9	85.3	90.2	89.3	87.7
2004	103.0	100.0	92.9	84.2	79.5	85.1	83.0
2005	85.6	82.4	70.7	73.8	74.7	79.8	81.3
2006	101.0	111.0	107.0	107.0	110.0	111.0	114.7
2007	105.0	101.0	100.0	100.0	99.1	96.4	95.7
2008	102.0	103.0	103.0	101.0	97.3	98.2	99.2
2009	94.7	92.9	86.2	92.0	91.1	92.0	90.2
2010	88.5	79.2	71.8	69.7	70.9	74.0	84.7
2011	104.0	110.0	109.0	117.0	128.0	141.0	137.0
2012	86.0	91.2	98.8	112.9	120.0	117.8	129.4
2013	102.5	92.0	89.7	91.1	92.4	93.9	97.7
Minimum	79.2	66.4	58.6	56.1	56.5	55.5	58.2
Median	101.0	100.0	97.3	98.6	98.2	98.2	99.2
Maximum	138.0	145.0	142.0	149.0	153.0	159.0	159.0

2010 Modified Flows

The 2003 Entity Agreements on Principles and Procedures requires the Entities to use updated estimates of irrigation depletions and return flows when calculating the streamflows required by Treaty Protocol Section VIII for the Steps I, II, and III downstream power benefit studies. The latest Pacific Northwest Coordination Agreement (PNCA) process to update the net depletions and streamflow record to 80 years (WY 1929 through WY 2008) was completed in August 2011 and is referred to as the 2010 Modified Flows. The 2010 Modified Flows and the updated flood control rule curves, hydro-independent data and other data dependent on the updated streamflows were incorporated in the AOP18 Steps I, II, and III and the DDPB studies.

V - RESERVOIR OPERATION

General

The 2012-2013 Operating Year began with Canadian storage at 99.7 percent full. Libby Reservoir (Lake Koocanusa) was about 0.3 m (1 ft) from full, elevation 749.20 m (2,458.15 ft), at the start of the operating year (1 August 2012) and releasing water to meet Biological Opinion (BiOp) objectives for flow augmentation for listed salmon species in the U.S.

The water supply during the 2012-2013 Operating Year was above average in the Columbia Basin above Grand Coulee, and below average in the Snake River above Lower Granite. The actual runoff in the Canadian portion of the Columbia Basin measured at Birchbank was about 111 percent of normal for January through July 2013. The actual runoff for the overall Columbia Basin (U.S. and Canada combined) measured at The Dalles for January through July 2013 was 96 percent of normal.

The CRTOC signed one operating agreement – the Nonpower Uses Agreement during the 2012-2013 Operating Year (see Section III Operating Arrangements) that impacted Mica and Arrow operations. Canadian storage ended the 2012-2013 operating year on 31 July 2013, at 18.93 km^3 (15.35 Maf) or 99.1 percent full.

Canadian Storage Operation

At the beginning of the 2012-2013 Operating Year (1 August 2012), actual Canadian storage provided under Article II of the CRT (Canadian storage) was at 19.06 km^3 (15.45 Maf) or 99.7 percent full. Canadian Treaty storage drafted to a minimum of 5.0 km^3 (4.1 Maf) on 26 April 2013. Canadian composite storage refilled to 18.9 km^3 (15.4 Maf) or 99.1 percent full at the end of the operating year, 31 July 2013.

As specified in the 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 TSR plus Supplemental Operating Agreements, as long as this variance does not impact the ability of the Canadian system to deliver the sum of CRT-specified outflows or exceed the upper rule curves for CRT reservoirs. Variances from the TSR target 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 TSR. Conversely, an underrun occurs when actual project releases are less (contents are higher) than those specified by the TSR. Flex accounts for Mica, Revelstoke, Arrow, and Duncan are balanced at all times (i.e., sum to zero) to ensure that both underruns and overruns do not impact the total CRT release required at the Canadian-U.S. border. The terms “underrun and overrun” are used in the description of Mica Reservoir operations below.

Mica Reservoir

As shown in Chart 5, Mica (Kinbasket) Reservoir was at elevation 754.5 m (2.475.3 ft) entering the operating year on 1 August 2012. This was 0.1 m (0.3 ft) above the normal full pool elevation due to exceptional high basin inflows from rainfall runoff and extensive outages in spring 2012. The Kinbasket Reservoir reached its maximum 2012 elevation of 754.72 m (2476.10 ft) on 29 August 2012.

As is normal, Kinbasket Reservoir was then drawn down during the fall and winter to meet electrical demands. The Upper Columbia generating stations ran relatively hard during the winter of 2012-2013 in order to position the Kinbasket Reservoir in anticipation of an

above average spring runoff volume and for a planned extended unit outages during the spring and summer at Mica.

During the spring and summer, Kinbasket Reservoir operated to provide power and FRM and also to manage the unit outages. In the spring, Kinbasket Reservoir reached a minimum elevation of 722.8 m (2371.4 ft) on 24 April 2013, 2.7 feet higher than the 2012 minimum level on 21 April 2012. From early April through mid-July, Mica generation was reduced to near zero as system loads declined, and to accommodate a five week full-plant outage from early June to mid-July. Also during the period, B.C. Hydro sought and received permission in July 2013 from the B.C. Comptroller of Water Rights (CWR) to surcharge the reservoir on an interim basis by up to 0.3 m (1ft) up to 754.7 m (2476 ft) for power purposes. This request was driven primarily by the lengthy generation restrictions over spring/summer 2013 during the major Mica powerplant upgrade, but also by the above-normal inflow forecast. Mica generation was ramped up from mid-July through August to maximum possible generation with the two in-service units. The Kinbasket Reservoir reached its maximum level of 754.6 m (2475.8 ft) on 16 September 2013.

Inflow into Mica Reservoir was 101 percent of normal over the period August to December 2012. Over this same period, Mica outflow varied from a monthly average high of about 1,121 m^3/s (39.6 kcfs) in August 2012 to a monthly average low of about 650 m^3/s (23 kcfs) in December 2012. Inflow into Mica Reservoir was about 108 percent of normal over the period January to July 2013. Outflow over this same period varied from a monthly average high of 1149 m^3/s (40.6 kcfs) in January to a monthly average low of 55 m^3/s (2.0 kcfs) in June.

The Mica project had an underrun of 141.1 hm^3 (57.7 thousand second-foot-days [ksfd]) on 31 July 2012. The maximum underrun for the operating period was 2494.0 hm^3 (1019.6 ksfd) on 21 September 2012, and the maximum overrun was 1737.2 hm^3 (710.2 ksfd) on 25 March 2012.

Under the 2012 NTSA, 3.5 km^3 (2.8 Maf) of empty Non-Treaty space was completely refilled across June/July 2012 during the peak of the freshet to minimize flood risk in the lower Columbia River. B.C. Hydro and BPA stored and released water under this agreement during August through November 2012 for power and nonpower objectives. B.C. Hydro's portion of the storage was then released during January and February 2013 to minimize spill risk at Mica later in the year. Additionally, in early July 2013, B.C. Hydro and BPA

developed a Summer Shaping Agreement utilizing empty Non-Treaty space at Mica to reduce high inflows in the lower Columbia River.

Revelstoke Reservoir

During the 2012-2013 Operating Year, the Revelstoke project was operated mainly as a run-of-river plant with the reservoir level maintained generally within 1.5 m (5.0 ft) of its normal full pool elevation of 573.0 m (1,880.0 ft). During the winter, the reservoir operated to a low elevation of 570.0 m (1,870.0 ft), or 3.1 m (10.0 ft) below full pool, to provide additional short-term generation.

Arrow Reservoir

As shown in Chart 6, at the start of the operating year, the Arrow Reservoir level was 440.0 m (1443.7 ft) on 1 August 2012, 0.1 m (0.3 ft) below full pool. The Canadian Treaty composite storage operation was consistent with the DOP TSR which followed ORCs throughout the period August 2012 – July 2013 other than for a brief period from 1 September – 31 October 2012 when the coordinated system was in proportional draft. During the operating year, the Arrow storage operation was consistent with the DOP TSR, Nonpower Uses Agreement and the Non-Treaty Summer Shaping Agreement between B.C. Hydro and BPA.

Local inflow into Arrow Reservoir was below normal at 96 percent over the period August to December 2012. Arrow outflow varied from a daily average high of 2,452 m^3/s (86.6 kcfs) on 8 August 2012 to a daily average low of 688 m^3/s (24.3 kcfs) in November.

Local inflow into Arrow Reservoir was 103 percent of normal over the period January to July 2013. Outflow over this same period varied from a monthly average low of 682 m^3/s (24.1 kcfs) in April to a monthly average high of 1991 m^3/s (70.3 kcfs) in July. The minimum level reached for Arrow Lakes Reservoir in the 2012-2013 operating year was 427.94 m (1404.0 feet) on 16 February 2013, 0.4 m (1.4 ft) higher than the 2012 minimum level.

In October 2012, under terms of the LCA, Canada exercised 68.5 hm^3 (28 ksfd) of LCA provisional draft. By mutual agreement, the LCA draft was not returned by the end of March 2013 but was delayed until the week of 28 September 2013.

As in past years, the Nonpower Uses Agreement was negotiated between the parties in order to manage Arrow Lakes Reservoir outflows to protect Canadian whitefish and rainbow trout spawning and improve downstream flow conditions for U.S. salmon. In January, Treaty flows were reduced to enable 1.2 km^3 (1 Maf) of Flow Augmentation storage consistent with the provisions under the Nonpower Uses Agreement. However, 1.1 km^3 (0.9 Maf) of Non-Treaty water was released in January, and Arrow actual outflows averaged about 1,970 m^3/s (70 kcfs) for the month. The 1 February 2013 system runoff forecast was substantially less than that on 1 January 2013, so a significant reduction in Treaty flows was required in mid-February. The average Arrow release dropped to 1,246 m^3/s (44 kcfs) for February. The lowest flow in February was 770 $m^3/$ (27.2 kcfs). This flow pattern resulted in a Tier 2 protection level for whitefish for the 2012-2013 Operating Year, as defined by arrangements between Canada's Department of Fisheries and Oceans and B.C. Hydro. During April and May of 2013, Arrow outflows were maintained at or above the 680 m^3/s (24 kcfs) to support rainbow trout spawning below Arrow at water levels that could be maintained until hatch.

Through April, the Arrow Reservoir was operated relatively high for that time of year, near its flood control level of 431 m (1414 ft). As basin inflows increased rapidly beginning in early May from snowmelt runoff, the Arrow Lakes Reservoir refilled rapidly to just below its normal full pool level by 3 July 2013. The reservoir reached its maximum elevation for the year of 440.0 m (1443.5 ft), or 0.1 m (0.5 ft) below full pool, on 3 July 2013.

A Summer Shaping Agreement between B.C. Hydro and BPA was used to store a total of 0.70 km^3 (0.56 Maf) into Non-Treaty Active storage in early July to limit Arrow releases for the benefit of both operating parties. By limiting Arrow releases, the total peak flow at Birchbank (5 July 2013) was held to a maximum of 4,460 m^3/s (157 kcfs), below the flood stage threshold of 5,100 m^3/s (180 kcfs). Water stored into Non-Treaty space in July under the Summer Shaping Agreement was released through early September.

From early July through September, the Arrow Reservoir drafted fairly quickly, due primarily to the extensive Mica powerplant outage. This resulted in much below normal inflow into Arrow; the reservoir level reached 431.9 m (1416.9 ft) on 30 September 2013.

Duncan Reservoir

Operation of the Duncan Reservoir during the 2012-2013 Operating Year followed all Treaty requirements and implemented the operational constraints agreed upon in the Duncan Water Use Plan (WUP) and ordered in the Water License Order (issued on 21 December 2007). As shown in Chart 7, the Duncan Reservoir refilled to 577.0 m (1892.9 ft) or 0.3 m (0.9 ft) above normal full pool on 23 July 2012, reaching the highest recorded level since the dam began operation in 1967. Duncan discharges were adjusted as needed from August through 3 September (Labour Day) to target a reservoir elevation of 575.5 +/-0.3 m (~1,888 +/-1 ft) as per the WUP requirements.

After Labour Day 2012, Duncan discharges were increased to maintain flows in the Duncan River below the Lardeau River confluence (DRL) gauging station at 250 m^3/s (8.8 kcfs) maximum to facilitate drafting of the reservoir prior to the start of the kokanee and whitefish spawning downstream of Duncan Dam. For the first three weeks of October, discharges were reduced to maintain a 73 m^3/s (2.6 kcfs) flow at DRL to facilitate spawning at lower flows to limit the risk of over-winter dewatering of redds. Discharges were increased in the last week of October 2012 to bring DRL to a maximum flow of 110 m^3/s (3.9 kcfs). These flows were maintained until 21 December, at which point flows were gradually ramped up to bring DRL to about 283 m^3/s (10 kcfs) to help support whitefish flows downstream of Keenleyside Dam and to meet month-end Treaty flood control requirements. For the first three weeks of January 2013, the Duncan discharge was kept fairly high (283 m^3/s, or 10 kcfs, at DRL) in order to continue to draft Duncan Reservoir and to help reduce Arrow flows in aid of whitefish spawning. Duncan flows were adjusted across the balance of January and February to meet the Treaty flood control target of 552.5 m (1812.5 ft) by 28 February 2013.

In most years, Duncan Reservoir is drafted to near empty between mid-April and early May. Duncan Reservoir reached its minimum level for the year of 546.85 m (1794.2 ft) on 28 April 2013. By comparison, in 2012, the reservoir reached a minimum elevation of

547.0 m (1794.7 ft) on 14 April 2012. The project was operated to provide the agreed minimum flow of 73 m^3/s (2.6 kcfs) flow at DRL as required for fish until early May when the freshet began abruptly and the Duncan Dam discharge was gradually reduced to 11 m^3/s (0.4 kcfs) to manage DRL flows below 120 m^3/s (4.2 kcfs) as per WUP requirements.

The reservoir discharge was reduced to a minimum of 3 m^3/s (0.1 kcfs) on 24 May 2013 to begin reservoir refill and manage the Kootenay Lake level. Releases from Duncan Reservoir were held at minimum until early July to avoid increasing the peak level of Kootenay Lake. Once the Kootenay Lake level began to recede, Duncan discharges were increased on 3 July to manage the rate of refill for Duncan Reservoir. Discharges were adjusted to refill Duncan Reservoir within the top 0.3 m (1 ft) of its normal operating range in early August 2013 as per WUP requirements.

By 7 August 2013, Duncan Reservoir peaked close to full pool at 576.64 m (1891.9 ft). Previously, the Duncan River flow at DRL peaked at 386 m^3/s (13.6 kcfs) on 7 July 2013. Duncan discharges were adjusted as needed from August through 2 September 2013 (Labour Day) to target a reservoir elevation of ~575.5 +/- 0.3 m (~1,888 +/- 1 ft). For the balance of September until the ramp down began this year on 21 September, project flows increased (to a maximum DRL flow of 250 m^3/s, or 8.8 kcfs) to draft the reservoir prior to the minimum flow period of 100 m^3/s (3.5 kcfs) between 27 September and 21 October.

Libby Reservoir

Operation of Libby Dam and Lake Koocanusa is shown in Chart 8 of this document. Lake Koocanusa ended July 2012 at elevation 749.2 m (2458.15 ft). Throughout most of July 2012, Libby Dam was operated for FRM due to record June and early July precipitation amounts. As a result of this inflow, releases were increased above powerplant capacity from 5 June through 27 July – spilling a total of 1.52 km^3 (1,236 kaf). From mid-July 2012 to the end of August 2012, the project was drafted slowly with outflows reduced gradually to 340 m^3/s (12 kcfs) by 24 August in preparation for the second and continuing season of the habitat restoration work in the Kootenai River requiring lower flows in September and October. The request for these special flow operations, which influenced reservoir levels, was presented to the Technical Management Team (and approved) as a System Operation Request, in the spring of 2012 (28 March). The reservoir drafted to elevation 747.28 m

(2451.7 ft) by 31 August 2012 and to elevation 746.25 m (2448.34 feet) by 30 September 2012. Outflow was gradually stepped down to 226 m^3/s (8 kcfs) by 3 September 2012. The final April – August 2012 inflow volume to the project was 11.3 km^3 (9.2 Maf) or 156 percent of normal (1981 – 2010, 30 year normal).

A flat release of 226 m^3/s (8 kcfs) was reached on 4 September 2012, and was held for the remainder of the month. The discharge of 226 m^3/s (8 kcfs) was selected to be volume neutral between being above 746.45 m (2449 ft) end of August, as had been planned, and 170 m^3/s (6 kcfs) for the month of September. Libby began September at elevation 747.25 m (2451.6 ft) and ended the month at 746.27 m (2448.4 ft), drafting slightly over the month.

By 4 October 2012, the releases had been reduced to 113 m^3/s (4 kcfs), the minimum project outflow. The flow was maintained throughout the month, as the habitat restoration work continued. The project filled about 0.5 m (1.6 feet) over the month of October, reaching 746.76 m (2450.0 ft) on 31 October. On 5 November 2012, Libby outflows were increased to 348 m^3/s (12.3 kcfs) and held there until 9 November. The project ended November at elevation 742.30 m (2435.4 ft), with some weekly shaping in outflow, which averaged 611 m^3/s (21.6 kcfs) over the entire month. All changes in outflow followed the ramp rate restrictions as described in the 2006 U.S. Fish and Wildlife Service's BiOp.

The December water supply forecast came in at (6.2 Maf) 106 percent of average which set the end of December FRM elevation to 734.87 m (2411 ft). In December, the project drafted for flood control with shaping for power benefits. The project's actual elevation on 31 December was 734.57 m (2410.0 ft). The reservoir was drafted lower than the required flood risk elevation target because the January FRM end-of-month elevation was expected to be lower than December's. Libby outflow averaged 614 m^3/s (21.7 kcfs) in December and inflow averaged 150 m^3/s (5.3 kcfs). Precipitation over the Kootenai Basin in December was noted at 118 percent of average by the NWRFC.

The first-of-month forecast for January was 117 percent of average and set the end-of-month target to 730.0 m (2395 ft) by 31 January. Releases for the month of January averaged 323 m^3/s (11.4 kcfs) while targeting the end-of-month required elevation. Libby Dam ended the month at 730.0 m (2395.1 ft) and releases were dropped to 113 m^3/s (4 kcfs) by 4 February 2013. Releases were held at 113 m^3/s (4 kcfs) until the end of April because

the first-of-month forecasts were less than January's and the end-of-month FRM required elevations were above the 730.0 m (2395 ft). The forecast, FRM elevation requirements, and end-of-month elevations can be seen below:

Lake Koocanusa **February to April forecasts, FRM requirements, and end-of-month elevation**			
Month	**Forecast (KAF)**	**FRM required elevation (ft)**	**Actual end-of-month elevation (ft)**
February	6384	2404.3	2395.1
March	6315	2405.8	2393.8
April	6189	2411.8	2394.2

The May water supply forecast was calculated to be 8.0 km^3 (6.5 Maf), or 110 percent of average. This value required a sturgeon flow augmentation volume of 1.4 km^3 (1.14 Maf). There was no requirement to spill for the 2013 sturgeon pulse and the peak releases for 14 days were only required to be at powerhouse capacity. The start of refill was set for 1 May in 2013 and VarQ releases were set at 510 m^3/s (18 kcfs) but releases were not increased to that point until 0900 on 6 May because inflow was not yet at or above 510 m^3/s (18 kcfs) following VarQ rules. The required VarQ was held until 11 May when flows were increased to powerhouse capacity for the first 7 days of the sturgeon pulse. The sturgeon pulses were designed to have two individual peaks of 7 days each to mimic (1) a local peak runoff below Libby Dam which generally occurs in the last half of May, and (2) the freshet runoff that occurs above Libby Dam which generally occurs in the first part of June. Both pulses were to full powerhouse flow only, with no spill. During this first sturgeon pulse, releases were reduced to 589 m^3/s (20.8 kcfs) on 14 May in order to keep Bonners Ferry, ID, below 537.7 m (1764.0 ft). Subsequently, the stage at Bonners Ferry, ID increased to 537.36 m (1763.0 ft) and releases were back to powerhouse capacity on 15 May. After 7 days of the first pulse, releases were decreased back to VarQ flows of 510 m^3/s (18 kcfs) on 18 May for 6 days. At 0700 hours on 24 May, releases were again increased to powerhouse capacity for the second peak and releases were held there until 0800 hours on 5 June (12 days), at which

point releases were ramped down gradually until the sturgeon volume was expended on 10 June. Releases were then adjusted to 453 m^3/s (16 kcfs), targeting an elevation between 745.24 m (2445 ft) and 746.76 m (2450 ft) on 30 June 2013.

From 18 June to 20 June, the Kootenai Basin was hit by a wraparound storm from the Gulf of Mexico which produced rain totals throughout the Basin of 2 to 4 inches in a 3-day span. Inflows increased from 850 m^3/s (30 kcfs) to 2,520 m^3/s (89 kcfs) on 22 June and the reservoir ended the month at elevation 748.62 m (2456.1 ft). As a result of this inflow, releases were increased above powerplant capacity from 22 June through 10 July – spilling a total of 0.25 km^3 (203 kaf). Beginning on 20 June, releases were increased from 453 m^3/s (16 kcfs) to 793 m^3/s (28 kcfs), slightly above powerhouse capacity, after it was evident the storm was not going to significantly hit the southern part of the Kootenai Basin. In order to control refill of the dam, releases were increased again to 850 m^3/s (30 kcfs) and finally to 1,019 m^3/s (36 kcfs) on 4 July. The reservoir reached its peak elevation of 749.14 m (2457.8 ft) on 5 July. Inflows dropped off quickly and releases were brought back down to the powerhouse capacity of 688 m^3/s (24.3 kcfs) on 11 July. Because this event hit in the upper Kootenai Basin, no downstream impacts occurred at Bonners Ferry, ID, from uncontrolled local runoff.

In order to accommodate a 2 unit outage beginning the third week of July and to try and get the reservoir to an elevation below 747.25 (2451.6 ft) on 31 August, releases were held at powerhouse capacity until 21 July and then were ramped down to 396 m^3/s (14 kcfs). This flow represented powerhouse capacity with only three units available and was held until the end of the month. The Lake Koocanusa was at an elevation of 748.74 m (2456.5 ft) at the end of July and 746.46 m (2449.0 ft) at the end of August 2013, with the final April-August runoff totaling 8.9 km^3 (7.2 Maf) (121 percent of 1981 – 2010, 30 year normal).

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay reached 534.60 m (1,753.80 ft) on 3 July 2012, the highest level since 1974. As runoff receded during July, Kootenay Lake drafted, and discharges from the lake continued to be maximized until the reservoir drafted to 533.1 m (1749.0 ft) on 30 July 2012. At that time, the Corra Linn spill

was gradually reduced and the Corra Linn forebay returned to its normal operating level. In August 2012, lake discharges were adjusted to draft Kootenay Lake according to the IJC Order for Kootenay Lake and target an elevation of ~ 531 m (1742 ft) between 15 September and 15 October for the kokanee shoal spawner operation.

Kootenay Lake is operated to meet numerous interests, including provision of minimum flow targets in the Kootenay River at the Brilliant Dam. Operations target a minimum flow of 510 m^3/s (18 kcfs) during most of the year from December to September and 453 m^3/s (16 kcfs) during October and November, although the target flows are subject to water availability. Due to low basin inflows and a priority kokanee shoal spawner operation in the fall of 2012, the flows at Brilliant Dam were gradually reduced below target in late September to 453 m^3/s (16 kcfs) to prevent further drafting of Kootenay Lake and to conserve water for fish. With prolonged dry conditions, a further reduction in flow to between 226-343 m^3/s (8-12 kcfs) at Brilliant Dam was implemented in October. By early November, as Libby and Duncan discharges increased, Brilliant Dam flows were increased to meet target minimum flows and then flows were increased up to 850 m^3/s (30 kcfs) to control the Kootenay Lake rate of refill. As Libby and Duncan continued high discharges in December, to control Kootenay Lake to the IJC Order level and prepare for the Brilliant Expansion outage in January 2013, higher releases from Brilliant Dam, 850 to 1,130 m^3/s (30 to 40 kcfs), were implemented. By 31 December 2012, Kootenay Lake was positioned at an elevation of 531.45 m (1,743.6 ft), 0.55 m (1.8 ft) below the maximum IJC Order for Kootenay Lake reference level. In January, the Brilliant Expansion powerplant was out of service and discharges were kept at the maximum Brilliant powerplant discharge of 680 m^3/s (24 kcfs) plus a spill of 85 m^3/s (3 kcfs) in order to manage Kootenay Lake levels below the IJC Order during the outage. Due to lower inflows in February, Brilliant discharges were gradually reduced to the minimum target of 510 m^3/s (18 kcfs). From 18 March onwards, the Corra Linn and Kootenay Canal projects were operated to maximize discharges from the lake, limited only by the natural channel constriction at Grohman Narrows. The lake reached its minimum level of 530.1 m (1739.2 ft) on 1 April 2013.

Despite maximum outflows from the lake, the Kootenay Lake level exceeded the IJC Order reference level on 4 April 2013 and remained above this reference level until the declaration of Spring Rise. During this time, Corra Linn and Kootenay Canal projects were

operated to discharge maximum possible ("free fall conditions" or also referred to as free flow in the U.S.) which kept the operation compliant with the IJC requirements.

The International KLBC, after consultation with Fortis BC, declared the Commencement of Spring Rise for Kootenay Lake on 9 April 2013. Following this declaration, the Corra Linn and Kootenay Canal projects continued to pass maximum discharge, limited only by Grohman Narrows, throughout the spring runoff period. Due to the very wet weather at the beginning of May and again in late June, Kootenay Lake had two peak levels this year: 533.12 m (1749.1 ft) on 23 May and then a second, slightly higher, peak of 533.20 m (1749.3 ft) on 26 June. By comparison, in 2012, the peak level was 534.6 m (1753.8 ft) on 3 July 2012 (the highest level since 1974). Discharge from the lake peaked at 2407 m^3/s (85 kcfs) on 26 June 2013. After the first peak, the lake level dropped to 532.94 m (1748.5 ft), and free fall conditions were terminated on 13 June. However, free fall recommenced on 21 June and continued until 9 July. At that time, the Corra Linn spill was gradually reduced and the Corra Linn forebay returned to its normal operating level. In August, lake discharges were adjusted to draft Kootenay Lake according to the IJC curve. On 15 August 2013, the lake level at Nelson dropped below 531.36 m (1743.32 ft) and the lake level was then held relatively steady until 1 September.

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 Operating Agreements. Consistent with all DOPs prepared since the installation of generation at Mica, the 2012-2013 and the 2013 -2014 DOPs were designed to achieve optimum power generation onsite in Canada and downstream in Canada and the U.S., in accordance with paragraph 7 of Annex A of the CRT.

Power operations for the whole Canadian storage are determined by the ORC, CRCs, Mica/Arrow project operating criteria, and nonpower constraints as utilized in the TSR. The ORC calculation includes the VRCs which 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 calculations for Mica, Arrow, and Duncan are shown in Tables 2 and 4, and Tables 2M and 4M. The calculations for Libby VRCs are shown in Tables 5 and 5M. Libby VRCs are used in the preparation of the TSR.

During the period covered by this report, Libby operated for power in October and November as described in the Libby Operating Plan. The December 2012 water supply forecast for April-August 2013 runoff came in at 7.6 km^3 (6.2 Maf) or 106 percent of average (based on the 1981-2010). Based on this forecast, the recommended draft for Libby Reservoir was 2.47 km^3 (2.0 Maf), to elevation 735 m (2411 ft) on 31 December. Libby was operated to its VarQ flood control storage reservation diagram. Both Libby and Duncan dams began refill at the beginning of May according to the Initial Controlled Flow (ICF) date.

Flood Control

Overall, the 2013 water supply to the Columbia Basin was around average. The upper Columbia Basin had higher than average flows, as did the Kootenai Basin which encountered higher than average precipitation in June. The Upper Snake Basin, on the other hand, had close to record low water supply. Most of the other sub-basins had roughly average flows, leading to an observed April-August volume at The Dalles of 107.4 km^3 (87.05 Maf), which is 99 percent of the 1981-2010 RFC normal. During the drawdown period, the reservoir system, including the Columbia River Treaty projects, is required to draft for flood control in preparation for the spring rise. Inflow forecasts and reservoir regulation modeling were done throughout the winter and spring. Mica, Arrow, and Duncan were operated according to the May 2003 FCOP. Libby was operated to its VarQ Storage Reservation Diagram and accompanying rules. The unregulated peak flow (based on the USACE SSARR program output) at The Dalles, Oregon, shown on Chart 13, was estimated at 14,200 m^3/s (503 kcfs) on 15 May 2013, and a regulated daily peak flow of 9,580 m^3/s (338 kcfs) occurred on 11 May 2013 as measured at the U.S. Geological Survey gage at The Dalles, Oregon. The

unregulated (USACE) peak stage at Vancouver, Washington, was calculated to be 5.6 m (18.4 ft) on 16 May 2013, and the peak observed stage was 3.1 m (10.3 ft) on 12 May 2013.

For the 2012-2013 Operating Year, the Canadian Entity elected to operate Mica and Arrow to the flood control storage allocations of 4.4 km^3 (3.6 Maf) maximum draft at Arrow and 5.03 km^3 (4.08 Maf) maximum draft at Mica, as allowed under the 2003 FCOP. This allocation was first incorporated in the AOP for 2006-2007.

Computations of the ICF for system flood control operation were made in accordance with the Treaty FCOP. For 2013, the computed ICFs at The Dalles, based on the various first-of-month water supply forecasts, are as follows:

Initial Controlled Flow at The Dalles

Based on	kcfs	m^3/s
January Forecast	336.2	9521
February Forecast	296.4	8392
March Forecast	293.5	8311
April Forecast	299.4	8478
May Forecast	296.6	8398

Refill at the projects commence according to the date when the unregulated flow at The Dalles is expected to equal or exceed the ICF. For WY 2013, the ICF date was declared as 11 May based on the April forecast ICF of 8,478 m^3/s (299 kcfs). The flood control objectives at The Dalles were for regulated flows to stay within a specified range of daily average and instantaneous maximum flows, and for the Grand Coulee dam elevation to be below a set end-of-month target. These ranges and maximum values varied throughout the refill season. For example, for the week of 10 May, the maximum allowed instantaneous flow was 350 kcfs at The Dalles, with the maximum 31 May Grand Coulee elevation of 1277 ft. As mentioned earlier, the observed daily peak flow at The Dalles this year was 10,126 m^3/s (358 kcfs), occurring on 11 May 2013. Table 6 shows the data used for the April ICF computation.

Chart 14 shows the relative filling of Arrow and Grand Coulee reservoirs during the refill period and compares real-time regulation to guidelines provided in Chart 6 of the 2003 CRT FCOP. As shown in the chart, starting 30 April, Arrow Reservoir filled faster relative to Grand Coulee compared to the guideline. Arrow Dam was operated to meet local as well as system flood control objectives and Grand Coulee was operated for system flood control.

Canadian Entitlement and Downstream Power Benefits

From 1 August 2012 through 30 September 2013, 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 Canadian-U.S. border. The amounts returned, before deductions for transmission losses and scheduling adjustments, are listed in Section III Operating Arrangements of this report, under the heading Canadian Entitlement.

For the period 1 August 2012 through 31 July 2013, the Canadian Entitlement amount, before deducting transmission losses, was 504.5 aMW of energy, scheduled at rates up to 1321 MW capacity. From 1 August 2013 through 30 September 2014, the amount, before deducting transmission losses, was 505.5 aMW of energy, scheduled at rates up to 1336 MW capacity. The Canadian Entitlement obligation was determined by the 2012-2013 and 2013-2014 AOP/DDPBs.

During the course of the 2012-2013 Operating Year, there were four curtailment events for Canadian Entitlement deliveries. These included a 43 MWh cut on 9 September 2012 due to a forest fire near Grand Coulee, a 48 MWh cut on 19 March 2013 due to transmission congestion within the BPA system, a 22 MWh cut on 25 April 2013 due to transmission line maintenance work, and a 28 MWh cut on 28 September 2013 due to transmission congestion in the Puget Sound area of Washington State. All of the curtailed power was delivered later within the same month of curtailment, as per agreements between the Entities, with the exception of the 28 September 2013 cut, which was delivered on 1 October 2013 (and, as such, also complied with established Entities' scheduling guidelines). The U.S. Entity also invited BPA's Susan Millar, a transmission system expert, to explain to the CRTOC the operating circumstances and grid congestion events that contributed to the unplanned, pro-rata cuts to firm transmission schedules in the Northwest in the spring months of 2012, which

included reductions to the Canadian Entitlements deliveries. This occurred at the 7 May 2013 meeting. In February 2013, BPA retired the PSANI congestion management tool and installed new flow gates in the Puget Sound area to better manage localized transmission congestion. No Entitlement power was disposed directly in the U.S. during 1 August 2012 through 30 September 2013, as allowed under 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."

The following Figure 3 shows the historic Canadian Entitlement amounts from the DDPB studies as compared to the estimated amount under the 1964 Canadian Entitlement Exchange Agreement.

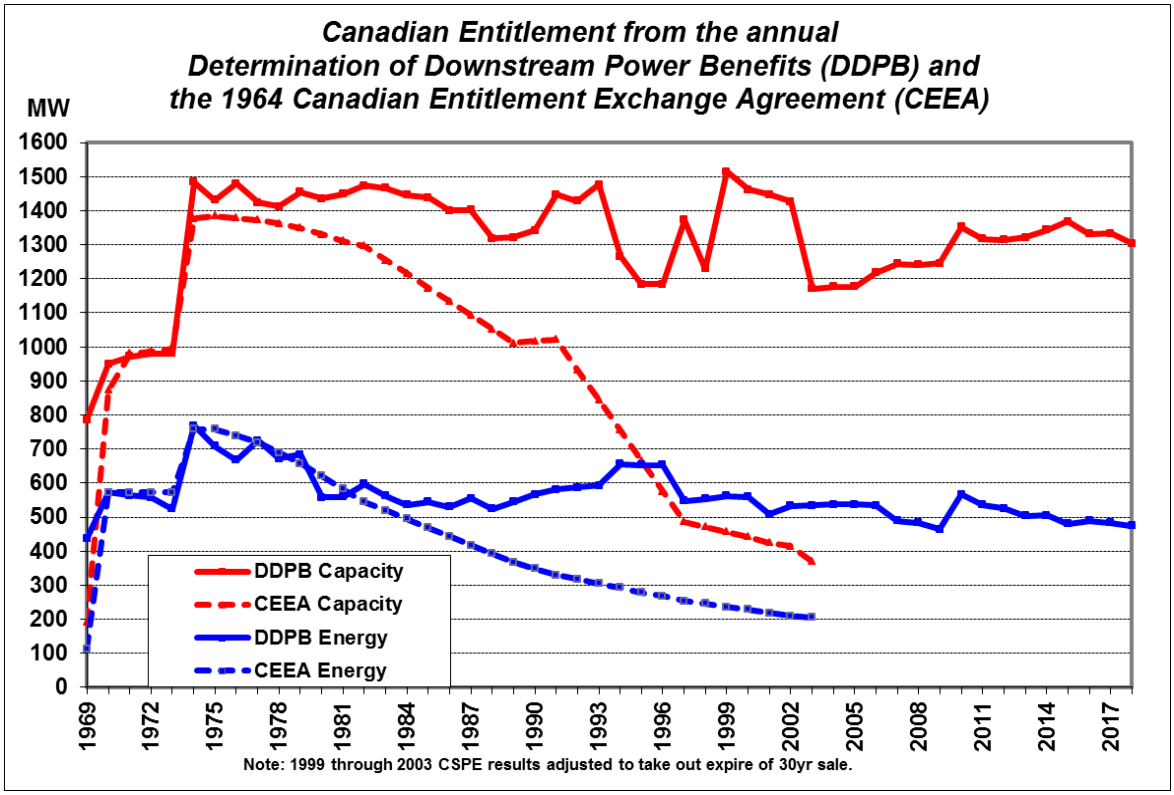


Figure 3: 2012-2013 Determination of Canadian Entitlement

The Canadian Entitlement Exchange Agreement estimates of the Canadian Entitlement were based on the forecast load growth that was much higher than the subsequent actual load growth. This load growth difference is the main reason for the large difference in the

Canadian Entitlement between the historic DDPBs and the Canadian Entitlement Exchange Agreement estimate.

In accordance with the Canadian Entitlement Allocation Extension Agreement, dated April 1997, the non-federal downstream U.S. projects delivered to BPA their portion of the Canadian Entitlement, and 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).

2014/2024 Review

During the period of this Annual Report, the U.S. Entity continued interaction with State, Federal, and Sovereign Review Team representatives to advance development of FRM, hydropower, and ecosystem based alternatives. The Entity CRT Review team, in cooperation with the Sovereign Technical Team, completed modeling efforts and analyses on Iteration 2 and 3 of Treaty review alternatives. The Iteration 3 evaluation included the ecosystem based function alternative proposed by the Sovereign Technical Team. Final results of the alternative analyses were summarized and presented to both Sovereign teams. Following completion of the alternative analyses, the periodic meetings with the Sovereign Technical Team ended in September.

Consultation between the U.S. Entity and the U.S. State Department continued regarding future Treaty review and stakeholder outreach activities. The U.S. Entity completed the initial draft of its proposed recommendation to the U.S. State Department. The draft was released to the regional sovereigns, stakeholders, and general public for comments on 27 June. Feedback on the initial draft has since been received and is being compiled and evaluated. The U.S. Entity is currently working on a revised draft that will be influenced by the results of the Iteration 3 analyses and the feedback from the stakeholders and general public.

The Canadian Entity during the year continued to coordinate with its stakeholders on future Treaty options. Canadian representatives from B.C. Hydro also provided feedback to several U.S. studies and papers. The B.C. Ministry of Energy and Mines released a paper in June entitled “U.S. Benefits from the Columbia River Treaty – Past, Present and Future: A Province of British Columbia Perspective.” This paper is under review by the U.S. Entity.

Power Generation and Other Accomplishments

Actual U.S. power benefits from the operation of Canadian storage can only be roughly estimated. Canadian storage has such a large impact on the operation of the U.S. system that its absence would significantly affect operating procedures, nonpower requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative.

The following Figure 4 shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2012-2013 Operating Year, with and without the regulation of Canadian storage, based on the PNCA AER that includes minimum flow and spill requirements for 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 552 aMW. In addition to the increase in average annual U.S. power generation, the Treaty regulation also shifted the timing of generation from the low value freshet period into higher value winter months. No quantification of this benefit is provided in this report. Figure 5 compares the actual operation of the composite Canadian storage to the results of the DOP TSR study.

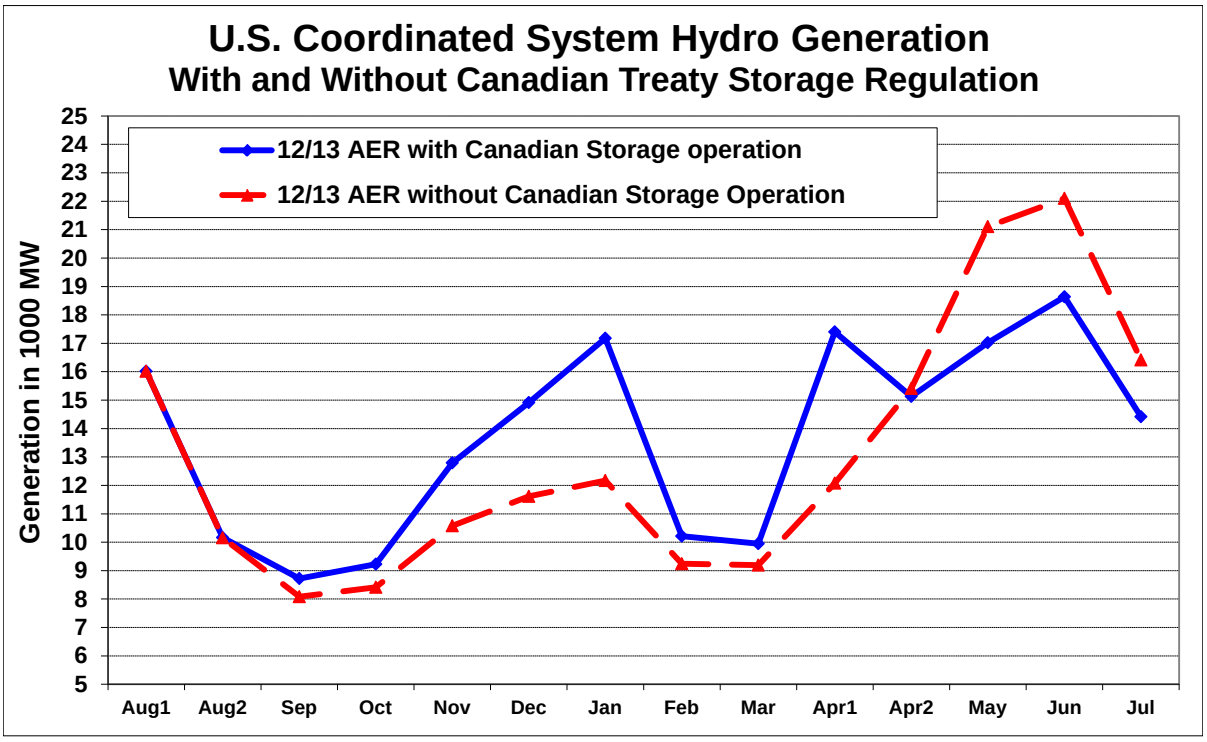


Figure 4: U.S. Coordinated System Hydro Generation

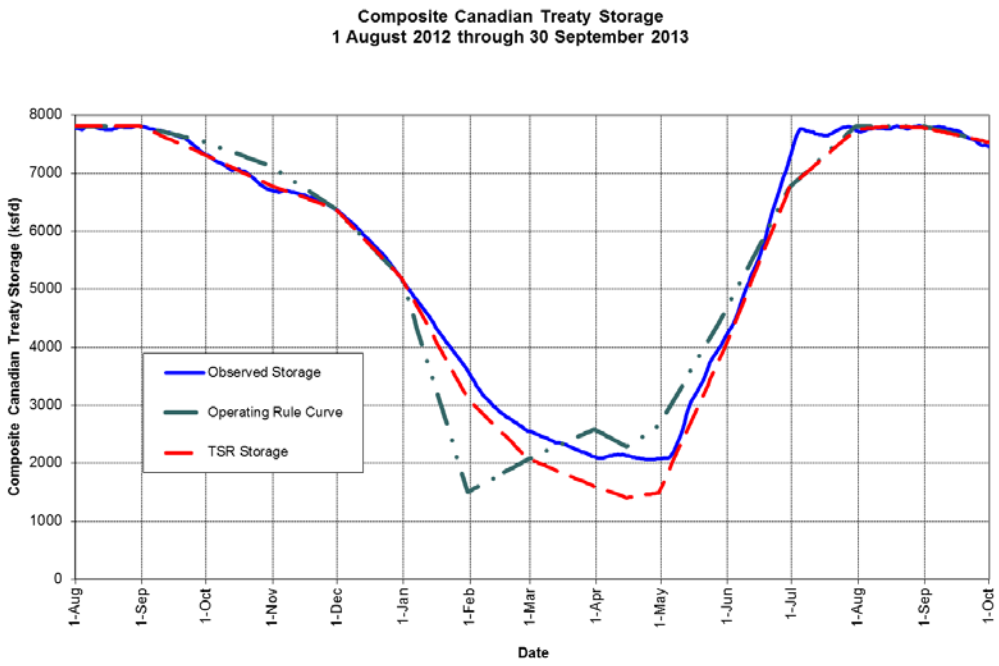


Figure 5: Composite Canadian Treaty Storage

A comparison of the TSR Storage Content with the ORC content shows that the TSR operated in proportional draft mode for September and October during the 2012-2013 Operating Year. Additionally, Arrow was on flow or storage restrictions beginning in January and March through May. Comparing the Observed Storage to the TSR Storage Content shows the impacts of Supplemental Operating Agreement operations such as flow augmentation storage.

Figure 6 shows the difference in Arrow plus Duncan regulated outflows in the DOP TSR and the actual daily CRT outflows due to the agreements. The daily unregulated inflows are also shown for comparison purposes. Note the magnitude and duration of the unregulated flows in May through early July – some fairly high runoff peaks during this overall-near-average water supply year.

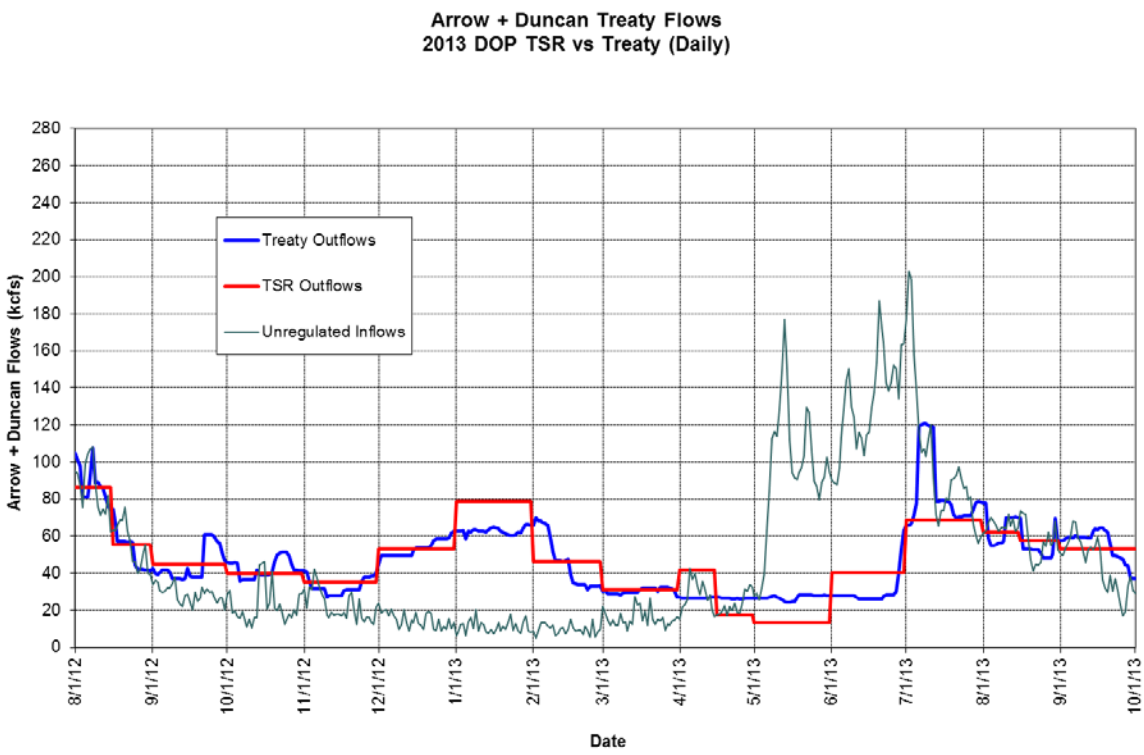


Figure 6: Arrow and Duncan Treaty Flows

Figure 7 summarizes the Treaty accounting including supplementary operating agreements throughout the year. Section I shows the difference for each period between the final TSR composite storage and the actual Treaty composite storage, including the supplementary agreements. Section II shows the storage balance for each supplementary agreement as it was implemented. Section III shows how the TSR storage content varies over time due to updated forecasts, unexpected weather events, and other factors. The final TSR target results are not available until after-the-fact, thus resulting in some inadvertent storage, as shown in Section II, Line 9.

Summary of Treaty Storage Operations

July 2012 through September 2013

All units in K SFD	2012							2013										
I. Composite Treaty Storage (ksfd)	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
1)Treaty Storage Regulation (Final)	7814.6	7814.6	7814.4	7326.1	6791.8	6394.7	5204.0	3111.3	2085.6	1607.8	1407.1	1494.2	4009.9	6759.6	7752.6	7807.9	7790.5	7544.2
2) Actual Treaty Content (w SOA's)	7792.2	7757.9	7811.9	7336.9	6713.0	6389.4	5189.0	3583.6	2559.7	2111.5	2133.5	2084.9	4176.7	7240.0	7742.4	7769.3	7804.5	7475.5
3) % full (actual Treaty 7814.6 ksfd)	100.0%	100.0%	100.0%	93.7%	86.9%	81.8%	66.6%	39.8%	26.7%	20.6%	18.0%	19.1%	51.3%	86.5%	99.2%	99.9%	99.7%	96.5%
4) Final deviation from TSR	**-22.4**	**-56.7**	**-2.5**	**10.8**	**-78.8**	**-5.3**	**-15.0**	**472.3**	**474.1**	**503.7**	**726.4**	**590.7**	**166.8**	**480.4**	**-10.2**	**-38.6**	**14.0**	**-68.7**

II. Monthly Accounting of Supplemental Operating Agreements Content (ksfd)

Balance in each period	2012 JUL	AU1	AU2	SEP	OCT	NOV	DEC	2013 JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
5) Libby Coord Agreement (LCA)	0.0	0.0	0.0	0.0	-28.0	-28.0	-28.0	-28.0	-28.0	-28.0	-28.0	-28.0	-28.0	-28.0	-28.0	-28.0	-28.0	-16.0
6) Non Power Uses Dec Provisional Drat	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7) Non Power Uses Flow (NPU) FA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	0.0	0.0	0.0	0.0
8) Total	0.0	0.0	0.0	0.0	-28.0	-28.0	-28.0	476.0	476.0	476.0	476.0	476.0	476.0	476.0	-28.0	-28.0	-28.0	-16.0
9. Inadvertent (Line 4 - Line 8)	**-22.4**	**-56.7**	**-2.5**	**10.8**	**-50.8**	**22.7**	**13.0**	**-3.7**	**-1.9**	**27.7**	**250.4**	**114.7**	**-309.2**	**4.4**	**17.8**	**-10.6**	**42.0**	**-52.7**
									(NPU avg Feb-Mar)		(NPU Shaping; inadvertent does not apply.)							

III. Summary of TSR Results August 2012-July 2013 (Final TSR in green)

Composite Treaty Storage TSR Content (ksfd)

TSR Date	2012 JUL	AU1	AU2	SEP	OCT	NOV	DEC	2013 JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	2013 SEP
8-Aug-12	**7814.6**	7814.6	7814.4	7544.2	7116.5	6394.7	5204.1	3069.5	1781.3	1205.7	982.1	1073.2	2971.2	6018.2	7752.6			
23-Aug-12		**7814.6**	7814.4	7544.2	7127.1	6394.8	5204.0	3069.5	1781.3	1335.8	1112.3	1203.4	3101.4	6148.4	7752.6			
6-Sep-12			**7814.4**	7507.7	7047.6	6394.7	5204.0	3069.4	1781.3	1072.7	1116.3	1207.3	3105.4	6152.3	7752.6			
24-Sep-12				7295.0	6705.7	6056.9	5204.0	3069.5	1781.3	1431.5	1382.7	1473.8	3371.8	6418.8	7752.6			
5-Oct-12				**7326.1**	6627.1	5756.7	5093.5	2959.3	1781.3	1311.1	1087.6	1178.7	3076.7	6123.6	7752.6			
22-Oct-12					6704.8	5982.9	5152.6	3018.1	1781.3	1193.9	970.3	1061.4	2959.4	6006.4	7752.6			
7-Nov-12					**6791.8**	6394.7	5204.0	3069.5	1781.3	1358.8	1135.3	1226.3	3124.4	6171.3	7752.6			
19-Nov-12						6394.7	5204.0	3086.5	1781.3	1391.8	1168.3	1259.4	3157.4	6204.4	7752.6			
12-Dec-12						**6394.7**	5204.0	3075.7	1448.5	1069.4	1066.8	1201.6	3085.9	6163.5	7752.6			
19-Dec-12							5204.0	3075.7	1468.6	1089.5	1087.0	1207.8	3092.2	6169.8	7752.6			
11-Jan-13							**5204.0**	3092.7	1455.5	1065.5	1048.2	1243.7	3146.7	6270.0	7752.6			
24-Jan-13								3092.1	1477.0	1086.4	1069.7	1262.1	3212.2	6283.2	7752.6			
13-Feb-13								**3111.3**	2085.6	1500.8	1299.8	1435.4	3480.6	6374.9	7752.6			
21-Feb-13									2085.6	1520.3	1316.9	1452.6	3476.0	6382.7	7752.6			
13-Mar-13									**2085.6**	1577.8	1373.0	1482.5	3434.9	6330.0	7752.6			
25-Mar-13										1613.3	1428.3	1554.3	3424.2	6357.8	7752.6			
10-Apr-13										**1607.8**	1416.4	1563.4	3477.4	6308.8	7752.6			
24-Apr-13											**1407.1**	1511.2	3410.3	6368.0	7752.6			
10-May-13												**1494.2**	4062.5	6503.7	7752.6			
23-May-13													4051.6	6574.7	7752.6			
10-Jun-13													**4009.9**	6647.4	7752.6			
20-Jun-13														6729.0	7801.1	7814.6	7803.0	
10-Jul-13														**6759.6**	7814.6	7814.6	7794.3	
25-Jul-13															7770.7	7814.6	7774.9	7283.0
8-Aug-13															**7752.6**	7783.6	7758.5	7188.3
22-Aug-13																**7807.9**	7771.4	7221.2
6-Sep-13																	**7790.5**	7343.0
19-Sep-13																		7544.2
4-Oct-13																		**7544.2**

Figure 7: Summary of Treaty Storage Operation

VII – TABLES

Table 1M (metric): Unregulated Runoff Volume Forecasts Cubic Kilometers

Most Probable 1-April through 31-August Forecasts in km^3

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.82	29.12	14.28	8.51	113.52
February	2.56	28.18	14.12	7.87	100.98
March	2.44	27.22	13.71	7.79	99.14
April	2.54	27.88	14.15	7.63	100.91
May	2.58	27.97	13.94	8.06	101.76
June	2.74	28.42	14.50	7.97	103.19
Actual	2.68	28.34	14.40	8.85	107.38

Table 1: Unregulated Runoff Volume Forecasts Million Acre-feet

Most Probable 1-April through 31-August Forecasts in Maf

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.28	23.61	11.57	6.90	92.03
February	2.08	22.84	11.44	6.38	81.86
March	1.97	22.07	11.11	6.32	80.37
April	2.06	22.60	11.48	6.19	81.81
May	2.09	22.68	11.30	6.54	82.50
June	2.22	23.04	11.76	6.46	83.66
Actual	2.17	22.98	11.67	7.17	87.05

Table 2M (metric): 2013 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			12.0	11.8	11.2	11.2	10.4	8.4
PROBABLE DATE-31JULY INFLOW, hm3	**		11981.2	11763.3	11169.5	11209.1	10446.7	8367.6
95% FORECAST ERROR FOR DATE, hm3			1802.7	1276.7	1113.6	1028.0	982.2	971.2
95% CONF.DATE-31JULY INFLOW, hm3	1/		10178.5	10486.6	10055.9	10181.1	9464.6	7396.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		10178.5					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		4651.7					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3107.7					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		737.6					
JAN31 ORC, m	7/		738.8					
BASE ECC, m	8/	740.5						
LOWER LIMIT, m		731.9						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		9975.0	10276.9				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		4446.2	4737.6				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3105.8	3095.3				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		738.8	738.8				
FEB28 ORC, m	7/		738.8	738.8				
BASE ECC, m	8/	740.2						
LOWER LIMIT, m		729.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		9730.7	10025.2	9814.5			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0			
MIN APR1-JUL31 OUTFLOW, hm3	4/		4218.7	4510.1	4732.3			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3122.5	3119.4	3552.3			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		738.9	738.9	740.0			
MAR31 ORC, m	7/		738.9	738.9	740.0			
BASE ECC, m	8/	740.3						
LOWER LIMIT, m		729.7						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.7	90.7	92.5	94.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		9231.9	9511.3	9301.7	9651.7		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		3998.5	4289.9	4512.1	4375.2		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3401.1	3413.1	3844.9	3358.1		
VRC APR30 RESERVOIR CONTENT, METERS	6/		739.6	739.7	740.8	739.5		
APR30 ORC, m	7/		739.6	739.7	740.2	739.5		
BASE ECC, m	8/	740.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		7308.2	7529.4	7360.9	7635.8	7486.5	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0	85.0	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		3770.9	4062.3	4284.5	4147.7	4021.7	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		5097.3	5167.5	5558.2	5146.4	5169.7	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		744.1	744.3	745.3	744.3	744.3	
MAY31 ORC, m	7/		744.1	744.3	744.7	744.3	744.3	
BASE ECC, m	8/	745.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		3705.0	3817.1	3720.7	3858.6	3785.8	3742.6
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		509.7	509.7	588.8	649.2	612.0	577.8
MIN JUL1-JUL31 OUTFLOW, hm3	4/		2449.8	2536.1	2601.9	2561.3	2524.0	2481.7
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7379.3	7353.5	7515.7	7337.2	7372.7	7373.6
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.9	749.8	750.2	749.8	749.9	749.9
JUN30 ORC, m	7/		749.9	749.8	750.2	749.8	749.9	749.9
BASE ECC, m	8/	752.6						
JUL 31 ORC, m			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 (8634.54 hm3) 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 2: 2013 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			9713.3	9536.5	9055.1	9087.3	8469.2	6783.7
PROBABLE DATE-31JULY INFLOW, KSFD	**		4897.1	4808.0	4565.3	4581.5	4269.9	3420.1
95% FORECAST ERROR FOR DATE, KSFD			736.8	521.8	455.2	420.2	401.4	397.0
95% CONF.DATE-31JULY INFLOW, KSFD	1/		4160.3	4286.2	4110.1	4161.3	3868.5	3023.1
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		4160.3					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1901.3					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1270.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2420.0					
JAN31 ORC, FT	7/		2424.0					
BASE ECC, FT	8/	2429.6						
LOWER LIMIT, FT		2401.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		4077.1	4200.5				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1817.3	1936.4				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1269.4	1265.1				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2423.9	2423.9				
FEB28 ORC, FT	7/		2423.9	2423.9				
BASE ECC, FT	8/	2428.6						
LOWER LIMIT, FT		2394.8						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3977.2	4097.6	4011.5			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1724.3	1843.4	1934.2			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1276.3	1275.0	1451.9			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2424.1	2424.1	2428.0			
MAR31 ORC, FT	7/		2424.1	2424.1	2428.0			
BASE ECC, FT	8/	2428.7						
LOWER LIMIT, FT		2394.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.7	90.7	92.5	94.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		3773.4	3887.6	3801.9	3944.9		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1634.3	1753.4	1844.2	1788.3		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1390.1	1395.0	1571.5	1372.5		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2426.6	2426.7	2430.6	2426.2		
APR30 ORC, FT	7/		2426.6	2426.7	2428.4	2426.2		
BASE ECC, FT	8/	2430.6						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2987.1	3077.5	3008.6	3121.0	3060.0	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0	3000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1541.3	1660.4	1751.2	1695.3	1643.8	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2083.4	2112.1	2271.8	2103.5	2113.0	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2441.4	2442.0	2445.3	2441.8	2442.0	
MAY31 ORC, FT	7/		2441.4	2442.0	2443.2	2441.8	2442.0	
BASE ECC, FT	8/	2447.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1514.3	1560.2	1520.8	1577.1	1547.4	1529.7
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		18000.0	18000.0	20794.4	22925.2	21612.9	20404.3
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		1001.3	1036.6	1063.5	1046.9	1031.6	1014.3
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3016.2	3005.6	3071.9	2999.0	3013.5	3013.8
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2460.2	2460.0	2461.3	2459.9	2460.2	2460.2
JUN30 ORC, FT	7/		2460.2	2460.0	2461.3	2459.9	2460.2	2460.2
BASE ECC, FT	8/	2469.2						
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 3M (metric): 2013 Arrow Reservoir Variable Refill Curve

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, km3			25.7	24.7	23.3	23.1	21.4	15.4
& IN hm3	**		25659.9	24688.6	23337.4	23119.6	21373.7	15396.2
95% FORECAST ERROR FOR DATE, IN hm3			3626.0	2680.3	2333.4	1982.3	1767.6	1660.2
95% CONF.DATE-31JULY INFLOW, hm3	1/		19421.0	21993.7	21259.2	21505.0	20753.4	15788.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		22032.7					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		7153.6					
UPSTREAM DISCHARGE, hm3	4/		5526.8					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		0.0					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		420.0					
JAN31 ORC, m	7/		421.2					
BASE ECC, m	8/	429.6						
LOWER LIMIT, m		421.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		21526.0	21502.8				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		6811.1	9129.3				
UPSTREAM DISCHARGE, hm3	4/		5528.8	5539.3				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		0.0	1923.6				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		420.0	425.3				
FEB28 ORC, m	7/		420.2	425.3				
BASE ECC, m	8/	429.9						
LOWER LIMIT, m		420.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		20887.0	20864.5	20393.7			
MIN APR1-JUL31 OUTFLOW, hm3	3/		6431.9	8750.0	9150.0			
UPSTREAM DISCHARGE, hm3	4/		5512.0	5515.1	5082.3			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		0.0	2158.5	2596.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		420.0	425.9	427.0			
MAR31 ORC, m	7/		420.0	425.9	427.0			
BASE ECC, m	8/	420.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		19366.8	19345.9	18923.5	19616.6		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		6064.9	8383.1	8783.1	8536.7		
UPSTREAM DISCHARGE, hm3	4/		5233.4	5221.5	5032.7	5276.5		
VRC APR30 RESERVOIR CONTENT, hm3	5/		689.4	3016.5	3650.2	2954.4		
VRC APR30 RESERVOIR CONTENT, METERS	6/		422.0	428.0	429.5	427.9		
APR30 ORC, Fm	7/		422.0	428.0	429.5	427.9		
BASE ECC, m	8/	431.7						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		14387.4	14371.9	14050.8	14564.5	14566.0	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		5685.6	8003.8	8403.8	8157.5	7930.6	
UPSTREAM DISCHARGE, hm3	4/		3537.2	3467.0	3321.8	3488.2	3464.8	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		3593.4	5856.8	6432.6	5839.0	5587.2	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		429.4	434.3	435.6	434.3	433.8	
MAY31 ORC, m	7/		429.4	433.9	433.9	433.9	433.8	
BASE ECC, m	8/	437.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		6720.0	6712.7	6573.9	6806.6	6822.3	6427.6
MIN JUL1-JUL31 OUTFLOW, hm3	3/		3918.9	4507.8	4648.7	4561.9	4482.0	4391.4
UPSTREAM DISCHARGE, hm3	4/		1255.2	1281.1	1118.8	1297.3	1261.8	1260.9
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7212.0	7834.0	7951.5	7810.5	7679.4	7982.6
VRC JUN30 RESERVOIR CONTENT, METERS	6/		437.1	438.4	438.6	438.3	438.1	438.6
JUN30 ORC, m	7/		437.1	438.4	438.6	438.3	438.1	438.6
BASE ECC, m	8/	440.1						
JUL 31 ECC, m			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/ MAXIMUM(FULL CONTENT (8757.85 hm3) MINUS 2/ PLUS 3/ MINUS /4 OR LOWER LIMIT)
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: 2013 Arrow Reservoir Variable Refill Curve

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, KAF			20802.6	20015.2	18919.7	18743.2	17327.8	12481.8
& IN KSFD	**		10488.0	10091.0	9538.7	9449.7	8736.1	6292.9
95% FORECAST ERROR FOR DATE, IN KSFD			1482.1	1095.5	953.7	810.2	722.5	678.6
95% CONF.DATE-31JULY INFLOW, KSFD	1/		7937.9	8989.5	8689.3	8789.8	8482.5	6453.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		9005.4					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		2923.9					
UPSTREAM DISCHARGE, KSFD	4/		2259.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		0.0					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1377.9					
JAN31 ORC, FT	7/		1381.8					
BASE ECC, FT	8/	1409.4						
LOWER LIMIT, FT		1381.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		8798.3	8788.8				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		2783.9	3731.4				
UPSTREAM DISCHARGE, KSFD	4/		2259.8	2264.1				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		0.0	786.2				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1377.9	1395.4				
FEB28 ORC, FT	7/		1378.6	1395.4				
BASE ECC, FT	8/	1410.3						
LOWER LIMIT, FT		1378.6						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		8537.2	8528.0	8335.5			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		2628.9	3576.4	3739.9			
UPSTREAM DISCHARGE, KSFD	4/		2252.9	2254.2	2077.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		0.0	882.2	1061.3			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1377.9	1397.4	1400.9			
MAR31 ORC, FT	7/	1411.8	1377.9	1397.4	1400.9			
BASE ECC, FT	8/	1377.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7915.8	7907.3	7734.6	8017.9		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		2478.9	3426.4	3589.9	3489.2		
UPSTREAM DISCHARGE, KSFD	4/		2139.1	2134.2	2057.0	2156.7		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		281.8	1232.9	1491.9	1207.6		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1384.6	1404.3	1409.1	1403.8		
APR30 ORC, FT	7/		1384.6	1404.3	1409.1	1403.8		
BASE ECC, FT	8/	1416.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5880.6	5874.2	5743.0	5952.9	5953.6	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		2323.9	3271.4	3434.9	3334.2	3241.5	
UPSTREAM DISCHARGE, KSFD	4/		1445.8	1417.1	1357.7	1425.7	1416.2	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1468.7	2393.9	2629.2	2386.6	2283.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1408.7	1425.0	1429.0	1424.9	1423.2	
MAY31 ORC, FT	7/		1408.7	1423.6	1423.6	1423.6	1423.2	
BASE ECC, FT	8/	1436.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2746.7	2743.7	2686.9	2782.1	2788.5	2627.1
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1601.8	1842.5	1900.1	1864.6	1831.9	1794.9
UPSTREAM DISCHARGE, KSFD	4/		513.0	523.6	457.3	530.2	515.7	515.4
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2947.7	3202.0	3250.0	3192.4	3138.8	3262.7
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1434.1	1438.2	1438.9	1438.0	1437.2	1439.1
JUN30 ORC, FT	7/		1434.1	1438.2	1438.9	1438.0	1437.2	1439.1
BASE ECC, FT	8/	1444.0						
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/ MAXIMUM(FULL CONTENT (3579.6 KSFD) MINUS 2/ PLUS 3/ MINUS /4 OR LOWER LIMIT)
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 4M (metric): 2013 Duncan Reservoir Variable Refill Curve

			INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			2.4	2.2	2.1	2.1	2.0	1.5	
& IN hm3	**		2408.2	2219.1	2072.8	2094.0	1990.1	1502.2	
95% FORECAST ERROR FOR DATE, IN hm3			309.0	255.2	256.8	229.5	212.6	190.8	
95% CONF.DATE-31JULY INFLOW, hm3	1/		2099.2	1963.9	1815.9	1864.6	1777.4	1311.5	
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0						
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		2099.2						
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8						
MIN FEB1-JUL31 OUTFLOW, hm3	4/		153.0						
VRC JAN31 RESERVOIR CONTENT, hm3	5/		0.0						
VRC JAN31 RESERVOIR CONTENT, METERS	6/		546.9						
JAN31 ORC, m	7/		551.7						
BASE ECC, m	8/	564.0							
LOWER LIMIT, m		551.7							
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1					
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		2059.3	1926.6					
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8					
MIN MAR1-JUL31 OUTFLOW, hm3	4/		146.2	197.8					
VRC FEB28 RESERVOIR CONTENT, hm3	5/		0.0	0.0					
VRC FEB28 RESERVOIR CONTENT, METERS	6/		546.9	546.3					
FEB28 ORC, m	7/		548.3	548.3					
BASE ECC, m	8/	560.0							
LOWER LIMIT, m		548.2							
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6				
ASSUMED APR1-JUL31 INFLOW, hm3	2/		2009.0	1879.4	1772.4				
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8				
MIN APR1-JUL31 OUTFLOW, hm3	4/		138.6	190.2	226.7				
VRC MAR31 RESERVOIR CONTENT, hm3	5/		0.0	37.6	181.2				
VRC MAR31 RESERVOIR CONTENT, METERS	6/		546.9	548.0	551.5				
MAR31 ORC, m	7/		546.9	548.0	551.5				
BASE ECC, m	8/	559.9							
LOWER LIMIT, m		546.9							
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.7	89.7	91.6	93.8			
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		1883.0	1761.6	1663.4	1749.0			
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8			
MIN MAY1-JUL31 OUTFLOW, hm3	4/		131.3	182.9	219.4	196.9			
VRC APR30 RESERVOIR CONTENT, hm3	5/		0.0	148.1	282.8	174.7			
VRC APR30 RESERVOIR CONTENT, METERS	6/		546.9	550.7	553.6	551.0			
APR30 ORC, m	7/		546.9	550.7	551.7	551.0			
BASE ECC, m	8/	561.0							
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3		
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		1417.0	1325.6	1253.0	1316.4	1338.4		
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	10.2	15.8	12.3		
MIN JUN1-JUL31 OUTFLOW, hm3	4/		123.7	155.6	177.1	163.9	151.7		
VRC MAY31 RESERVOIR CONTENT, hm3	5/		433.5	556.8	650.9	574.3	540.1		
VRC MAY31 RESERVOIR CONTENT, METERS	6/		556.5	558.7	560.3	559.0	558.4		
MAY31 ORC, m	7/		556.5	558.7	560.3	559.0	558.4		
BASE ECC, m	8/	567.0							
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2	
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		682.2	638.3	604.7	634.0	645.2	632.1	
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		17.0	17.0	23.8	28.9	25.8	22.8	
MIN JUL1-JUL31 OUTFLOW, hm3	4/		79.7	94.0	102.1	97.1	92.5	87.3	
VRC JUN30 RESERVOIR CONTENT, hm3	5/		1124.2	1182.6	1224.2	1190.0	1174.2	1182.0	
VRC JUN30 RESERVOIR CONTENT, METERS	6/		567.9	568.8	569.4	568.9	568.7	568.8	
JUN30 ORC, m	7/		567.9	568.8	569.4	568.9	568.7	568.8	
BASE ECC, m	8/	571.4							
JUL 31 ECC, 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 hm3) 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 THAN THE ARC OR CRC1 IN DOP

Table 4: 2013 Duncan Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1952.3	1799.0	1680.4	1697.7	1613.4	1217.9
& IN KSFD	**		984.3	907.0	847.2	855.9	813.4	614.0
95% FORECAST ERROR FOR DATE, IN KSFD			126.3	104.3	105.0	93.8	86.9	78.0
95% CONF.DATE-31JULY INFLOW, KSFD	1/		858.0	802.7	742.2	762.1	726.5	536.0
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		858.0					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		62.6					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		0.0					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1794.2					
JAN31 ORC, FT	7/		1810.0					
BASE ECC, FT	8/	1850.4						
LOWER LIMIT, FT		1810.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		841.7	787.4				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		59.8	80.9				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		0.0	0.0				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1794.2	1792.4				
FEB28 ORC, FT	7/		1798.8	1798.8				
BASE ECC, FT	8/	1837.4						
LOWER LIMIT, FT		1798.7						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		821.1	768.2	724.4			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		56.7	77.8	92.7			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		0.0	15.4	74.1			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1794.2	1798.0	1809.3			
MAR31 ORC, FT	7/		1794.2	1798.0	1809.3			
BASE ECC, FT	8/	1837.0						
LOWER LIMIT, FT		1794.2						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.7	89.7	91.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		769.6	720.0	679.9	714.9		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		53.7	74.8	89.7	80.5		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		0.0	60.5	115.6	71.4		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1794.2	1806.9	1816.2	1807.8		
APR30 ORC, FT	7/		1794.2	1806.9	1810.0	1807.8		
BASE ECC, FT	8/	1840.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		579.2	541.8	512.1	538.1	547.0	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	359.5	557.3	435.5	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		50.6	63.6	72.4	67.0	62.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		177.2	227.6	266.1	234.7	220.8	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1825.7	1833.0	1838.3	1834.0	1832.0	
MAY31 ORC, FT	7/		1825.7	1833.0	1838.3	1834.0	1832.0	
BASE ECC, FT	8/	1860.1						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		278.9	260.9	247.2	259.1	263.7	258.4
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		600.0	600.0	839.5	1022.2	909.7	806.1
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		32.6	38.4	41.7	39.7	37.8	35.7
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		459.5	483.4	500.4	486.4	479.9	483.1
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1863.2	1866.1	1868.2	1866.5	1865.7	1866.1
JUN30 ORC, FT	7/		1863.2	1866.1	1868.2	1866.5	1865.7	1866.1
BASE ECC, FT	8/	1874.7						
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 5M (metric): 2013 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			8.5	7.9	7.9	7.7	8.1	8.1
PROBABLE DATE-31JULY INFLOW, hm3			8521.0	7924.0	7879.5	7742.8	8131.3	8051.0
95% FORECAST ERROR FOR DATE, hm3			1853.3	1282.8	1174.4	1034.7	935.3	819.1
OBSERVED JAN1-DATE INFLOW, IN hm3			0.0	245.4	465.1	790.7	1455.5	4060.6
95% CONF.DATE-31JULY INFLOW, hm3	1/		6667.7	6395.7	6240.1	5917.1	5740.2	3171.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		6461.0					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		3005.9					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		2687.1					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		727.3					
JAN31 ORC, m	7/		727.3					
BASE ECC, m	9/	738.0						
LOWER LIMIT, m		718.3						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		6274.3	6210.2				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		2731.9	3139.0				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		2599.8	3071.0				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		726.6	730.5				
FEB28 ORC, m	7/		726.6	730.5				
BASE ECC, m	9/	737.1						
LOWER LIMIT, m		710.0						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		6040.9	5980.0	6009.3			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, hm3	4/		2428.5	2835.6	2835.6			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		2529.8	2997.8	2968.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		726.0	729.9	729.7			
MAR31 ORC, m	7/		726.0	729.9	729.7			
BASE ECC, m	9/	736.4						
LOWER LIMIT, m		699.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.3	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		5487.5	5436.3	5460.1	5378.9		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3	113.3		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		2134.9	2542.0	2542.0	2542.0		
VRC APR30 RESERVOIR CONTENT, hm3	5/		2789.6	3247.9	3224.1	3305.4		
VRC APR30 RESERVOIR CONTENT, METERS	6/		728.2	731.8	731.6	732.3		
APR30 ORC, m	7/		728.2	731.8	731.6	732.3		
BASE ECC, m	9/	736.1						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.1	57.0	58.6	60.9	67.0	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		3673.8	3645.4	3656.7	3603.6	3846.1	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		326.0	424.8	424.8	424.8	141.6	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		1831.5	2238.6	2238.6	2238.6	2238.6	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4299.9	4735.4	4724.1	4777.2	4534.8	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		738.9	741.6	741.5	741.8	740.4	
MAY31 ORC, m	7/		738.9	741.6	741.5	741.8	740.4	
BASE ECC, m	9/	743.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.4	20.9	21.8	23.9	35.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		1307.0	1304.8	1304.3	1289.8	1372.1	1135.2
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		368.3	424.8	424.8	424.8	141.6	424.8
MIN JUL1-JUL31 OUTFLOW, hm3	4/		986.5	1137.7	1137.7	1137.7	1137.7	1137.7
VRC JUN30 RESERVOIR CONTENT, hm3	5/		5821.9	5975.1	5975.6	5990.0	5907.8	6142.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		747.8	748.6	748.6	748.7	748.2	749.5
JUN30 ORC, m	7/		747.8	748.6	748.6	748.7	748.2	749.5
BASE ECC, m	9/	743.0						
JUL 31 ORC, m			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, km3	8/		126.4	113.5	110.6	112.4	114.0	115.8

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 5: 2013 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, KAF			6908	6424	6388	6277	6592	6527
PROBABLE JAN-31JULY INFLOW, KSFD			3482.8	3238.8	3220.6	3164.7	3323.5	3290.7
95% FORECAST ERROR FOR DATE, KSFD			757.5	524.3	480	422.9	382.3	334.8
OBSERVED JAN1-DATE INFLOW, IN KSFD			0	100.3	190.1	323.2	594.9	1659.7
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2725.3	2614.1	2550.5	2418.5	2346.2	1296.2
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		2640.8					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1228.6					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1098.3					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2386.3					
JAN31 ORC, FT	7/		2386.3					
BASE ECC, FT	9/	2421.4						
LOWER LIMIT, FT		2356.6						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		2564.5	2538.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1116.6	1283				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1062.6	1255.2				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2383.9	2396.5				
FEB28 ORC, FT	7/		2383.9	2396.5				
BASE ECC, FT	9/	2418.4						
LOWER LIMIT, FT		2329.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		2469.1	2444.2	2456.2			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		992.6	1159	1159			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1034	1225.3	1213.3			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2381.9	2394.6	2393.9			
MAR31 ORC, FT	7/		2381.9	2394.6	2393.9			
BASE ECC, FT	9/	2416.0						
LOWER LIMIT, FT		2293.4						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.3	85	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		2242.9	2222	2231.7	2198.5		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000	4000		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		872.6	1039	1039	1039		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1140.2	1327.5	1317.8	1351		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2389.2	2401	2400.4	2402.4		
APR30 ORC, FT	7/		2389.2	2401	2400.4	2402.4		
BASE ECC, FT	9/	2415.1						
		2287.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.1	57	58.6	60.9	67	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1501.6	1490	1494.6	1472.9	1572	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		11513.1	15000	15000	15000	5000	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		748.6	915	915	915	915	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1757.5	1935.5	1930.9	1952.6	1853.5	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2424.3	2433	2432.8	2433.8	2429.1	
MAY31 ORC, FT	7/		2424.3	2433	2432.8	2433.8	2429.1	
BASE ECC, FT	9/	2437.6						
		2287.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.4	20.9	21.8	23.9	35.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		534.2	533.3	533.1	527.2	560.8	464
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		13007.5	15000	15000	15000	5000	15000
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		403.2	465	465	465	465	465
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2379.6	2442.2	2442.4	2448.3	2414.7	2510.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2453.3	2456	2456	2456.3	2454.8	2459
JUN30 ORC, FT	7/		2453.3	2456	2456	2456.3	2454.8	2459
BASE ECC, FT	9/	2437.6						
		2287.0						
JUL 31 ORC, FT			2459.00	2459.00	2459.00	2459.00	2459.00	2459.00
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		102.5	92.0	89.7	91.1	92.4	93.9

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 6: Computation of Initial Controlled Flow

Columbia River at The Dalles, OR

Metric and English Units, based 1 April 2013 forecast

Upstream Storage Corrections	**Metric (km^3)**	**English (Maf)**
Mica	8.670	7.029
Arrow	4.441	3.600
Duncan	1.687	1.368
Libby	2.772	2.248
Hungry Horse	0.758	0.614
Flathead Lake	0.617	0.500
Noxon Rapids	0.000	0.000
Pend Oreille Lake	0.617	0.500
Grand Coulee	2.883	2.337
Brownlee	0.100	0.081
Dworshak	0.672	0.544
John Day	0.195	0.158
Total Upstream Storage Corrections	23.411	18.979

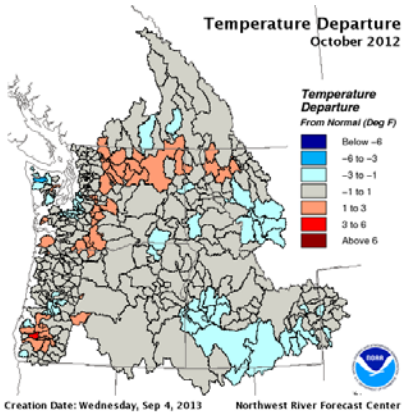
Adjusted TDA May-Aug Runoff Volume	**Metric (km^3)**	**English (Maf)**
TDA May-Aug Runoff Volume (1May Forecast)	84.993	68.905
Less Estimated Depletions	-2.061	-1.671
Less Total Upstream Storage Corrections	-23.411	-18.979
Adjusted TDA May-Aug Runoff Volume	59.522	48.255

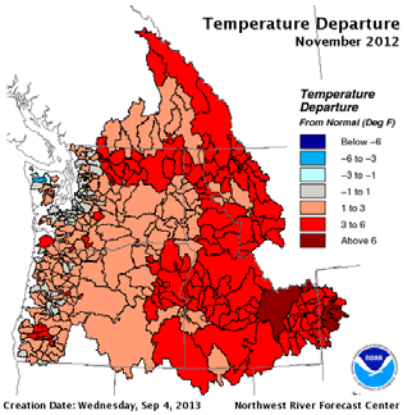
Initial Controlled Flow	**m^3/s**	**kcfs**
Determined using 'Adjusted TDA May-Aug Runoff Volume' and Chart 1 of the Flood Control Operating Plan	**8478**	**299.4**

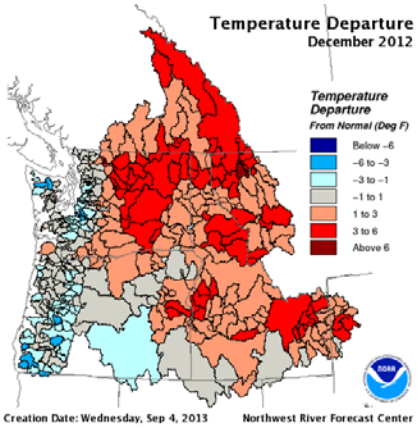
VIII - CHARTS

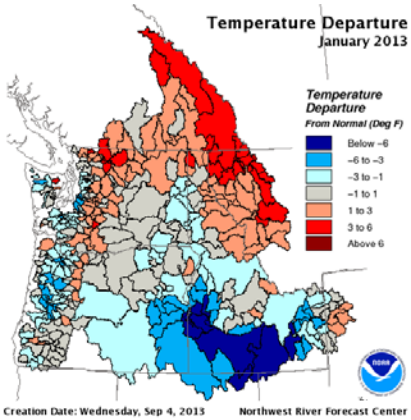
Chart 1: Pacific Northwest Monthly Temperature Departures

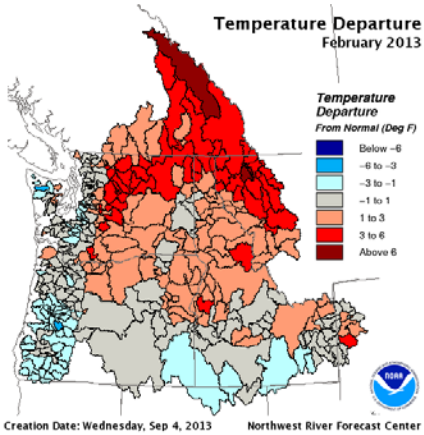
Oct – Mar











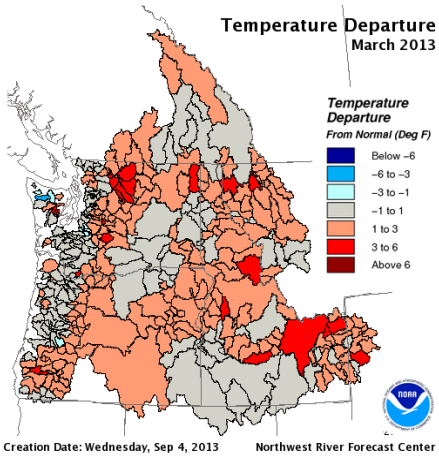
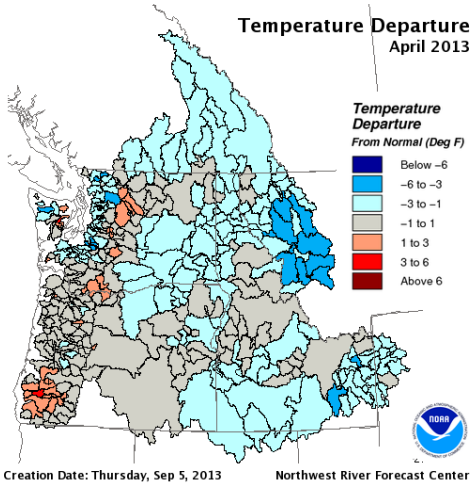
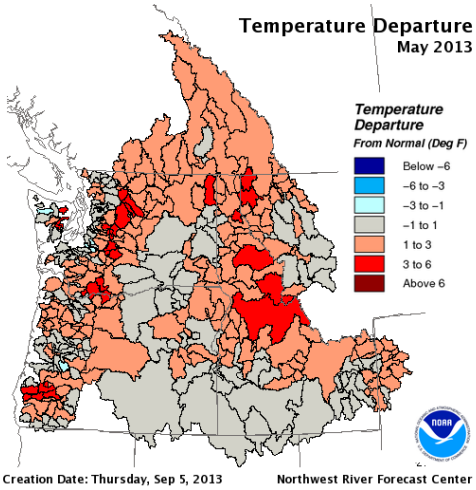
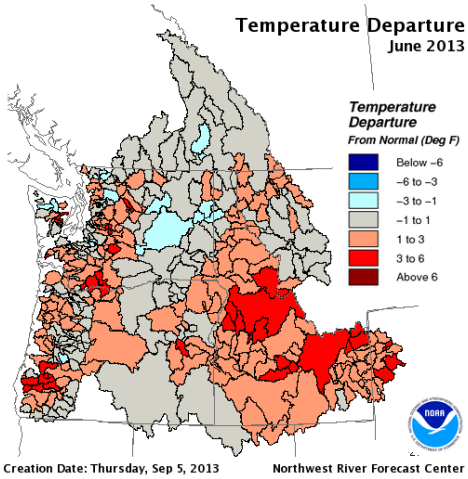
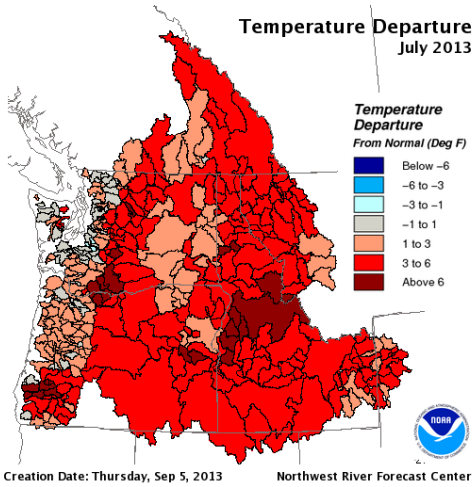


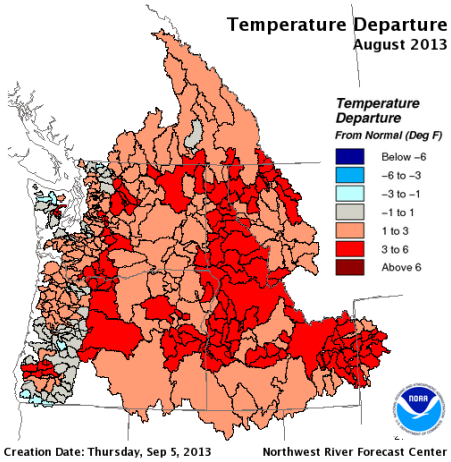
Chart 1: Pacific Northwest Monthly Temperature Departures (Continued)
April – September











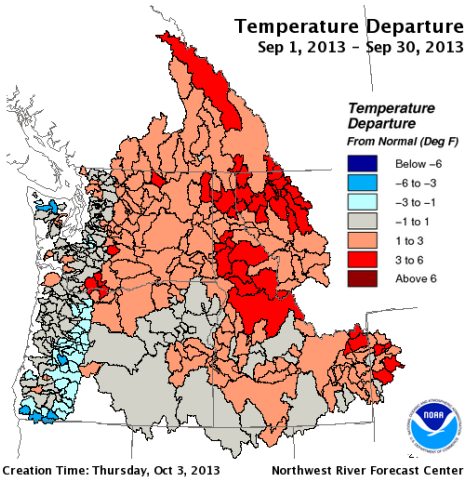
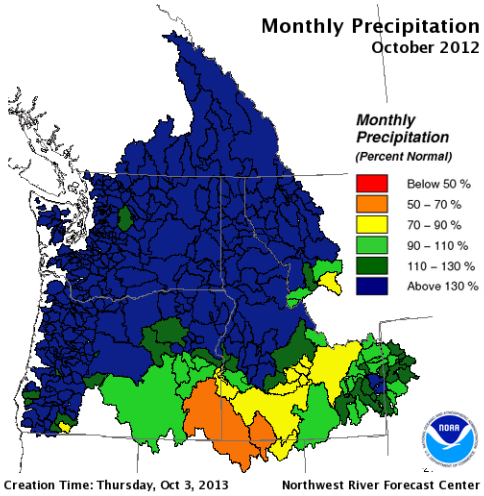
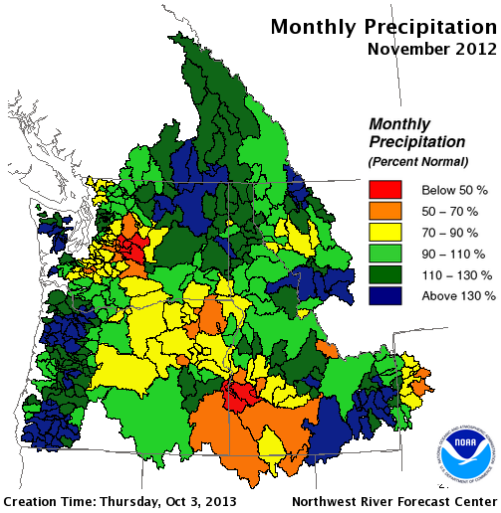
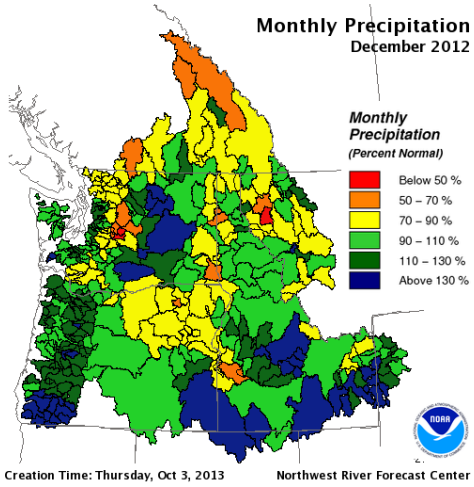


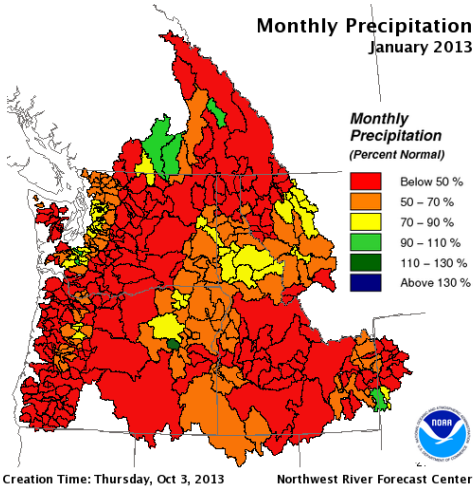
Chart 1 A: Pacific Northwest Monthly Precipitation

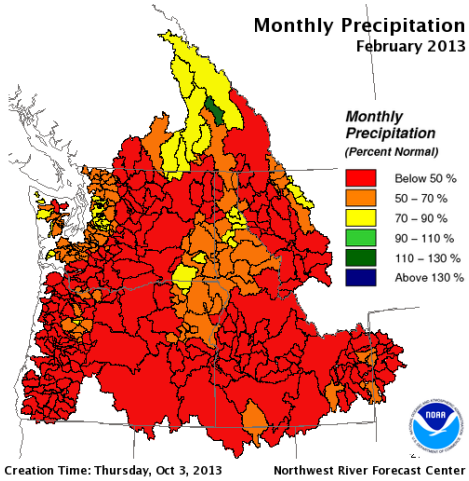
October – March











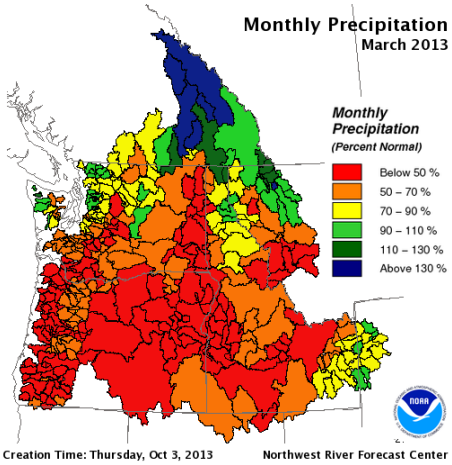
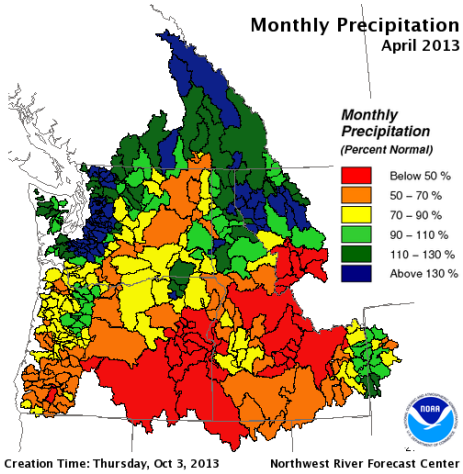
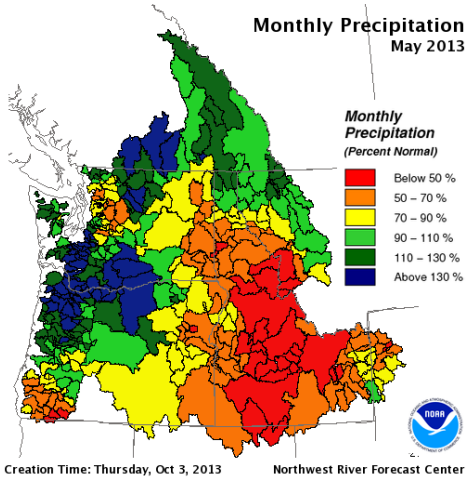
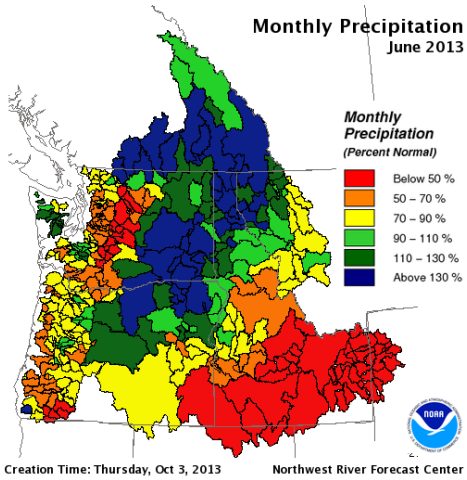
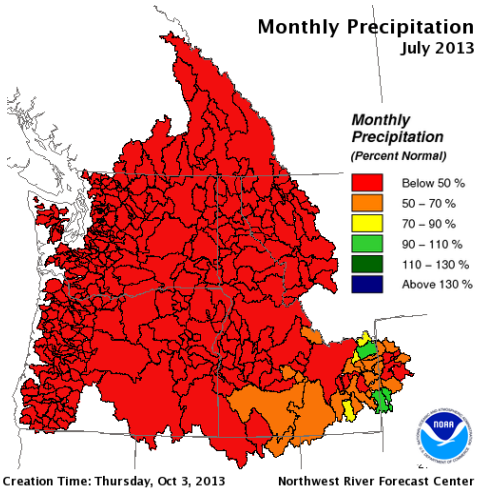


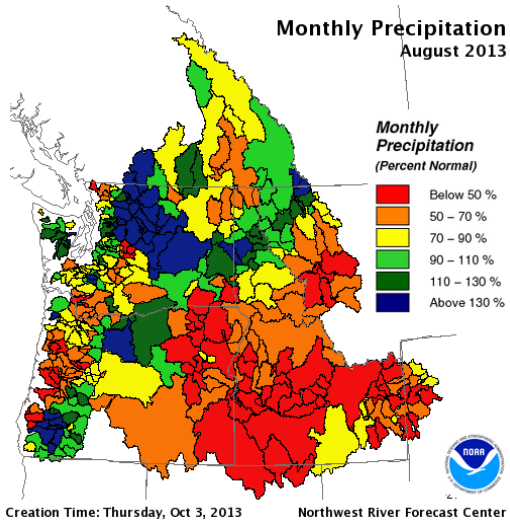
Chart 1 A: Pacific Northwest Monthly Precipitation (Continued)
April – September











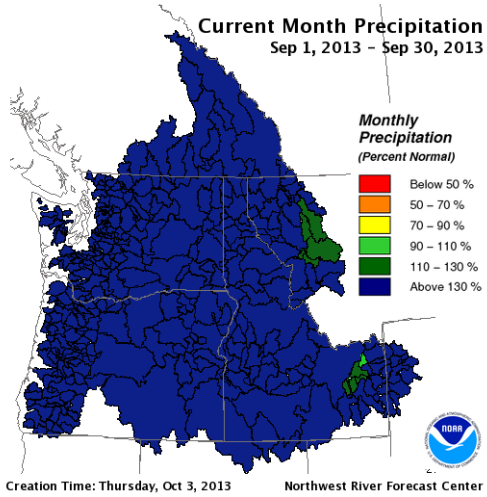


Chart 2: Seasonal Precipitation Columbia River Basin October 2012 – September 2013

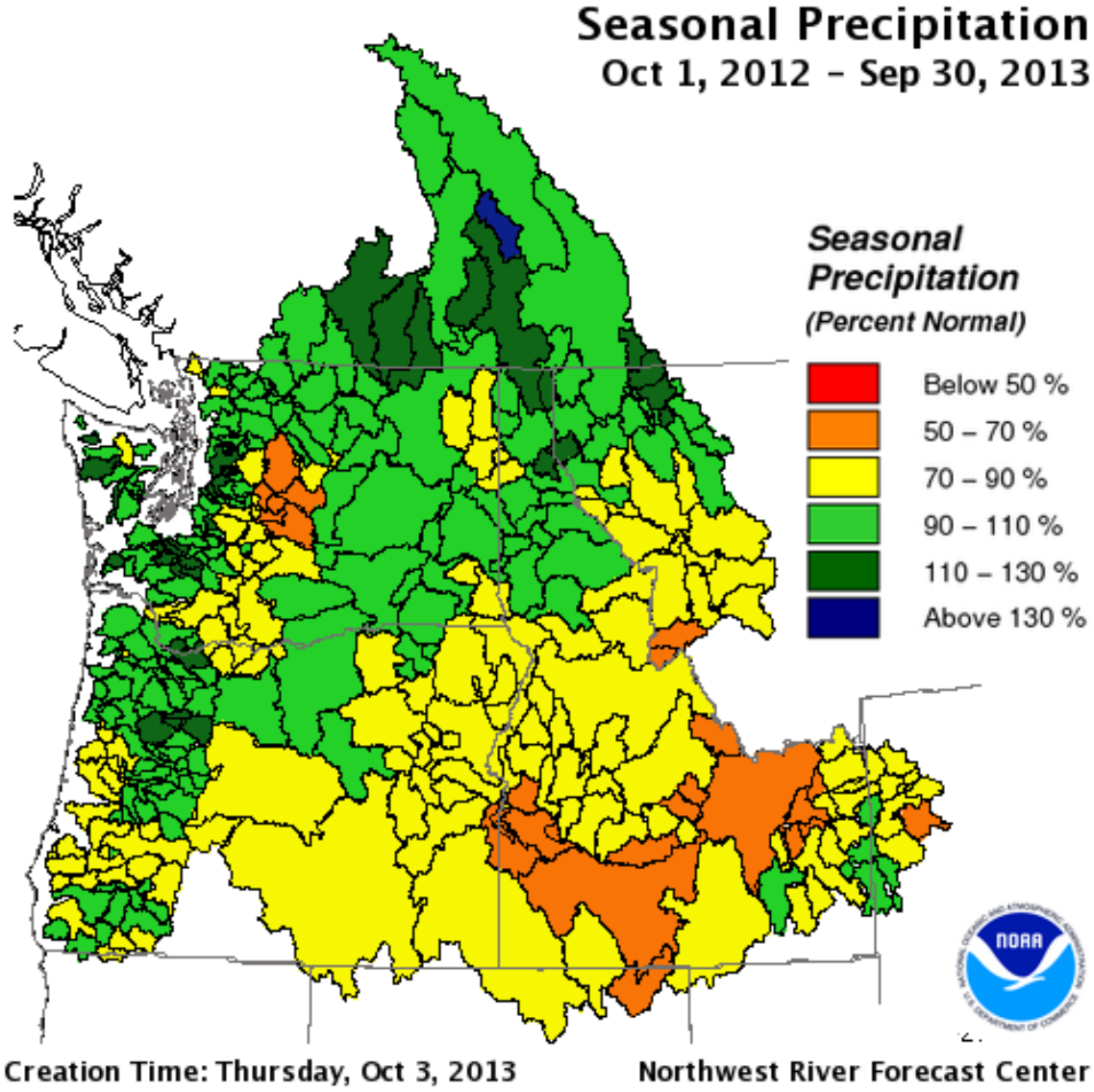
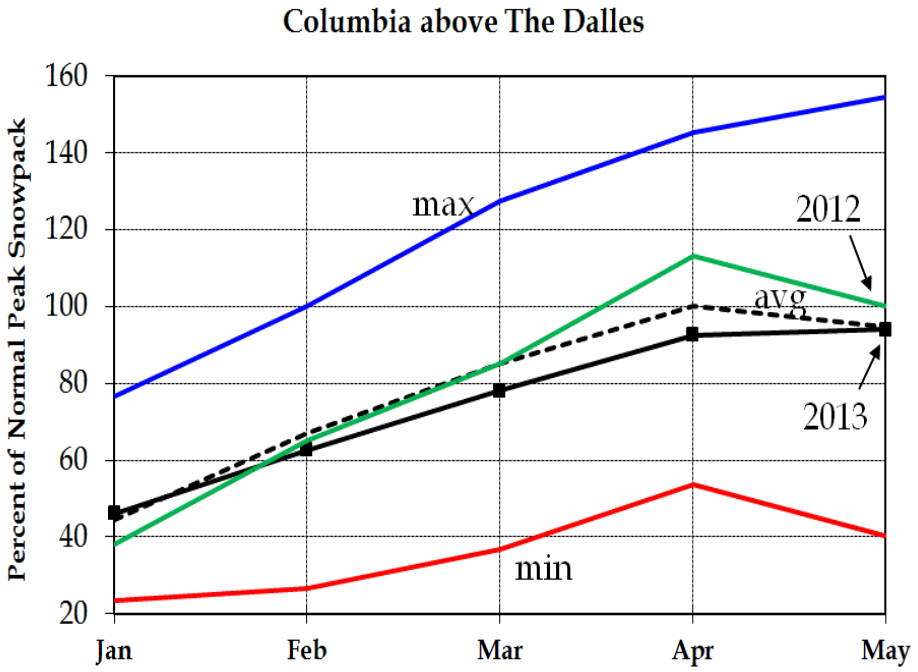


Chart 3: Columbia Basin Snowpack



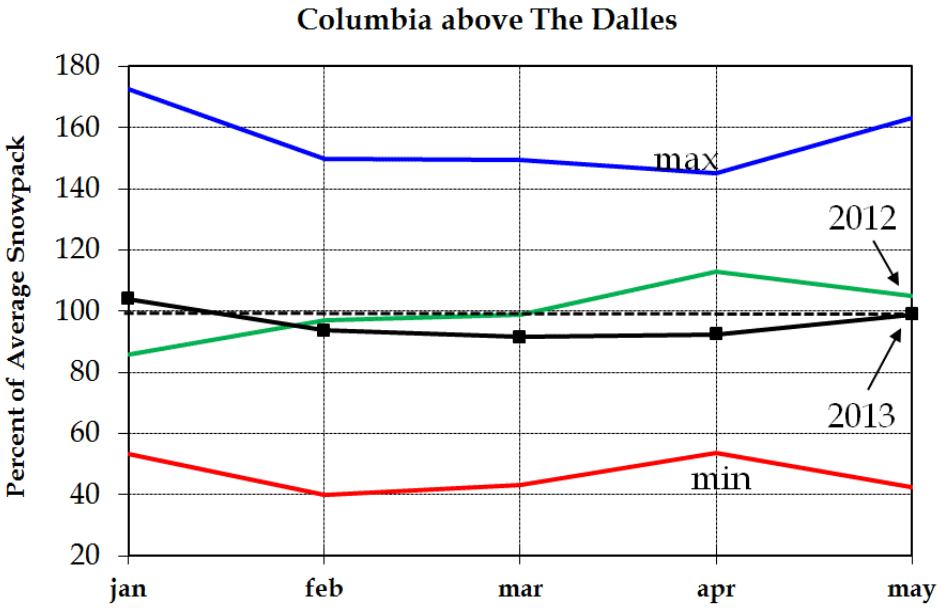
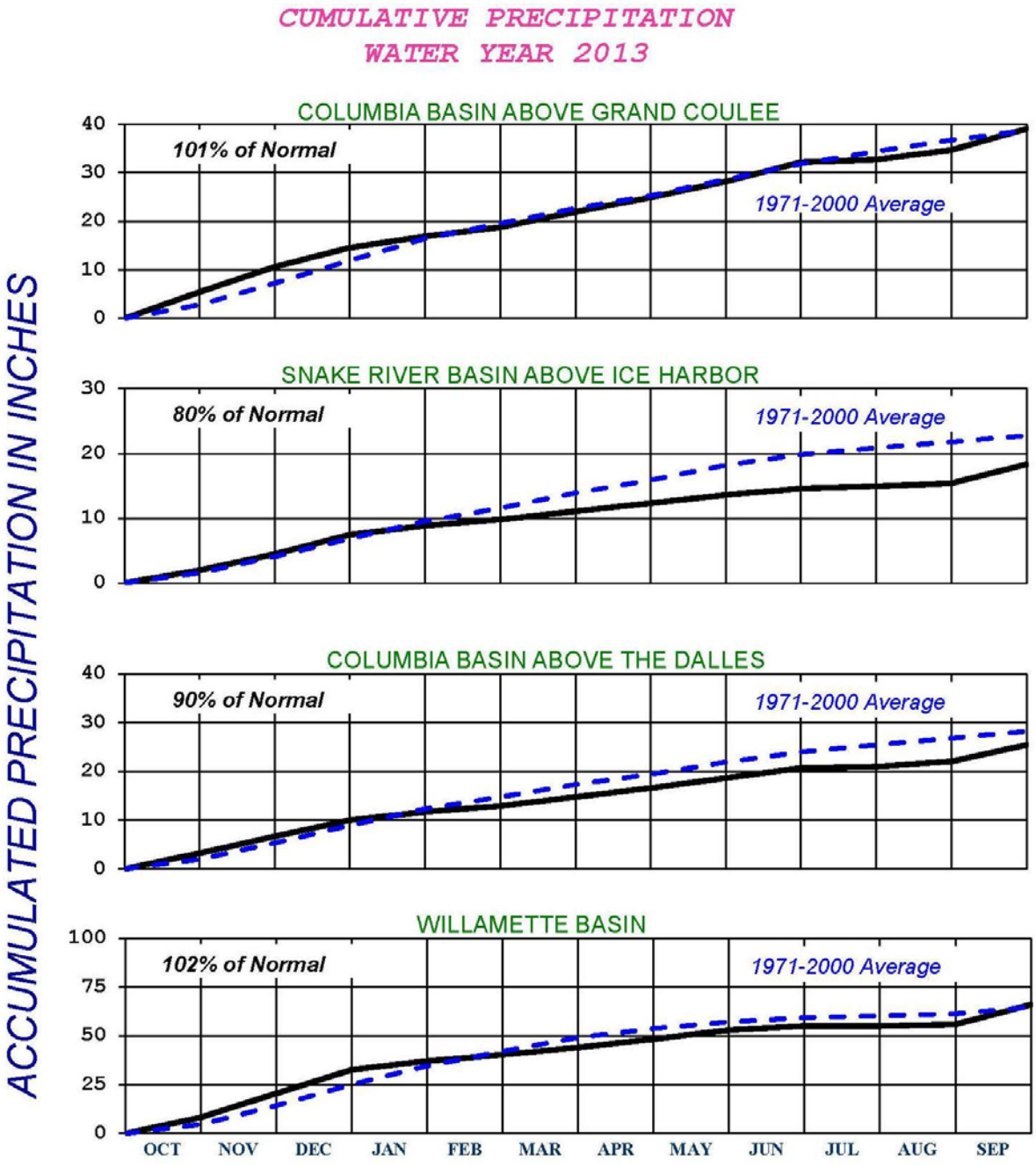


Chart 4: Accumulated Precipitation for WY 2013

At Primary Columbia River Basins



Note: NWRFC employed advanced methodology for WY 2013 to calculated basinwide rainfall depths. Currently, only 2013 data are available.

Chart 5: Regulation of Mica

1 July 2012 – 30 September 2013

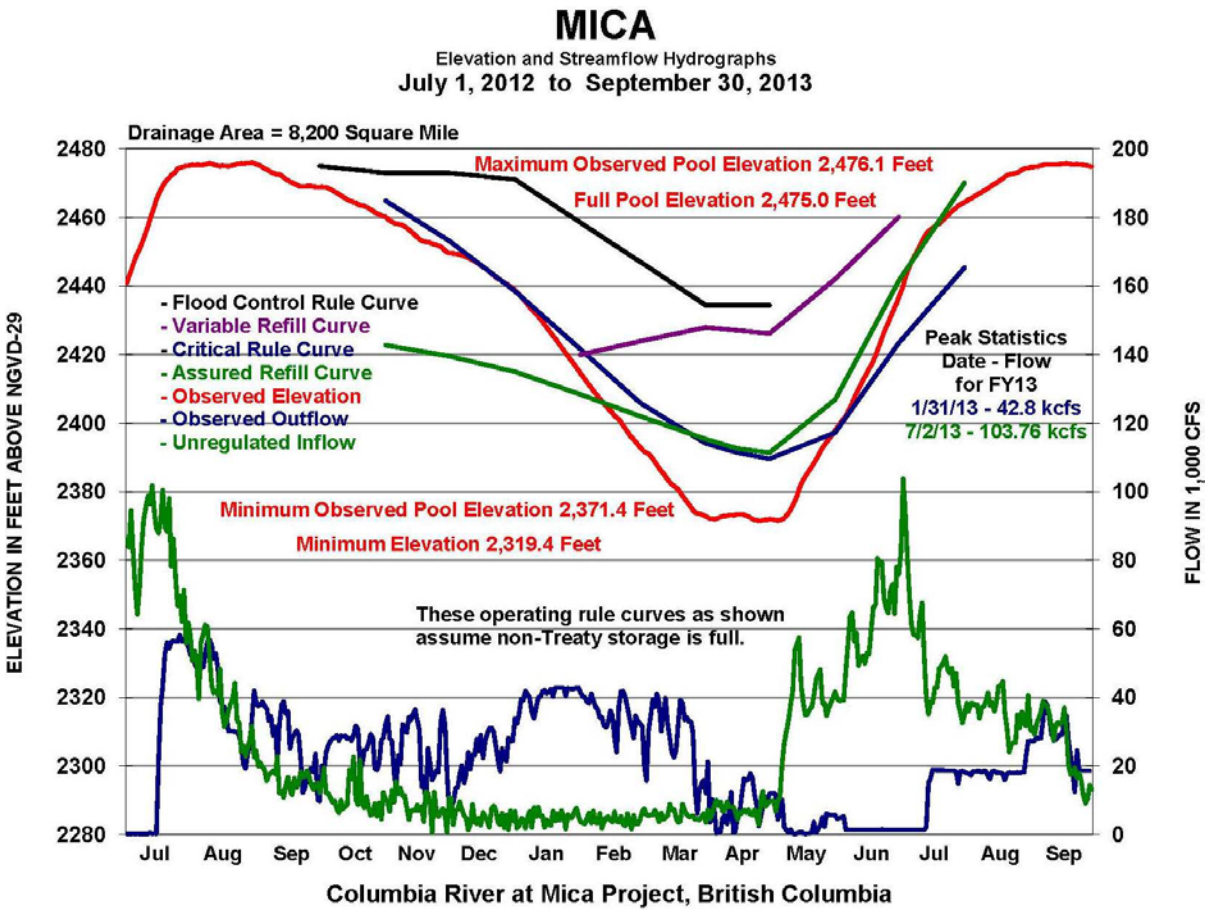


Chart 6: Regulation of Arrow 1 July 2012 – 30 September 2013

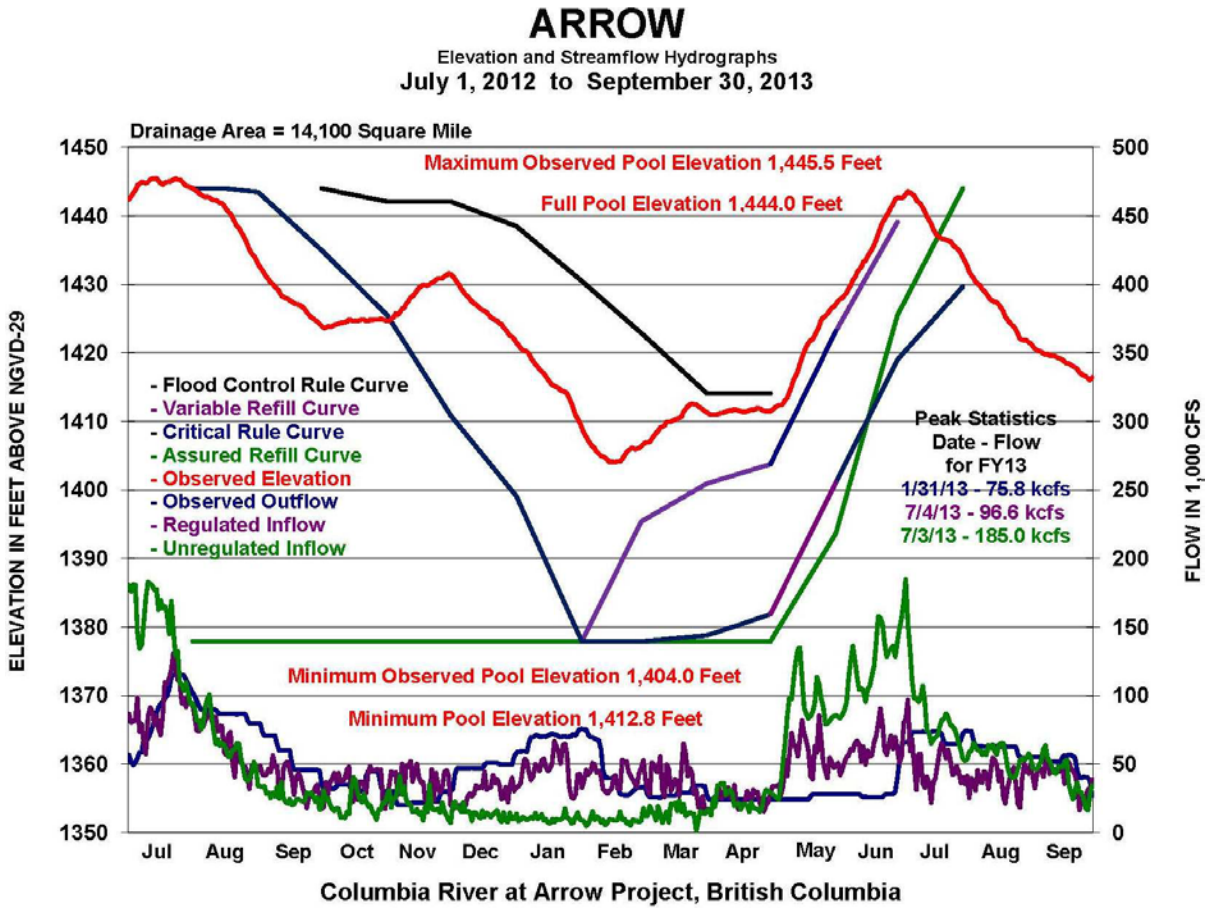


Chart 7: Regulation of Duncan

1 July 2012 – 30 September 2013

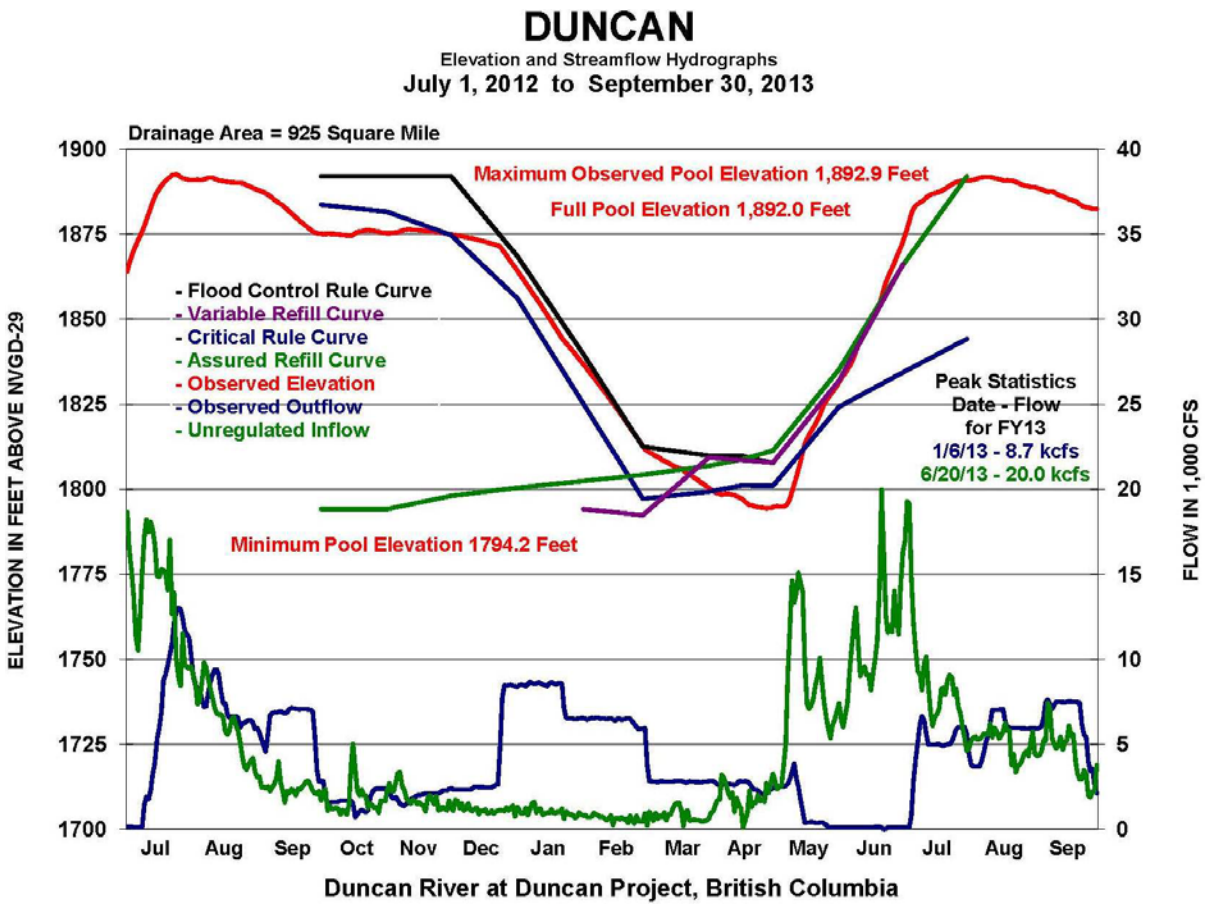


Chart 8: Regulation of Libby

1 July 2012 – 30 September 2013

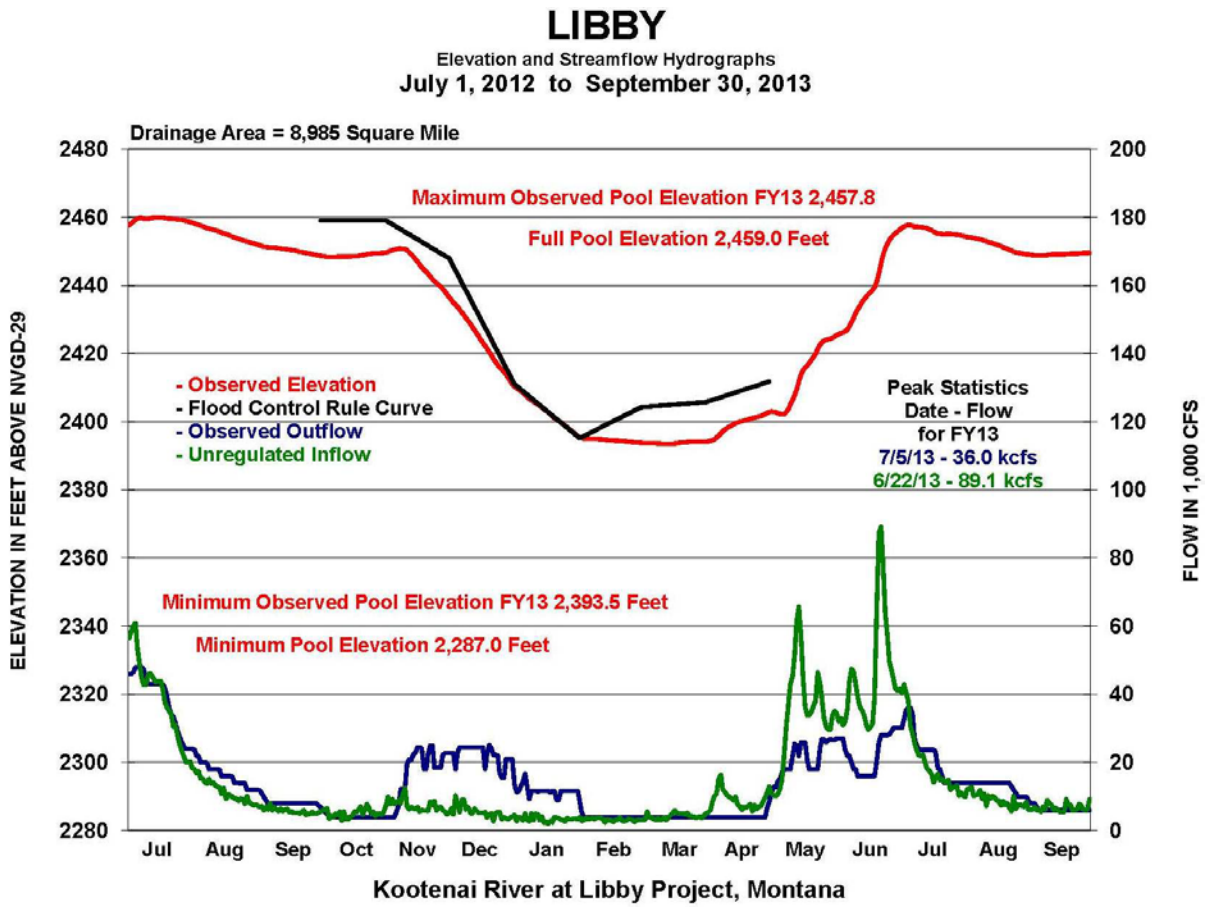


Chart 9: Regulation of Kootenay Lake

1 July 2012 – 30 September 2013

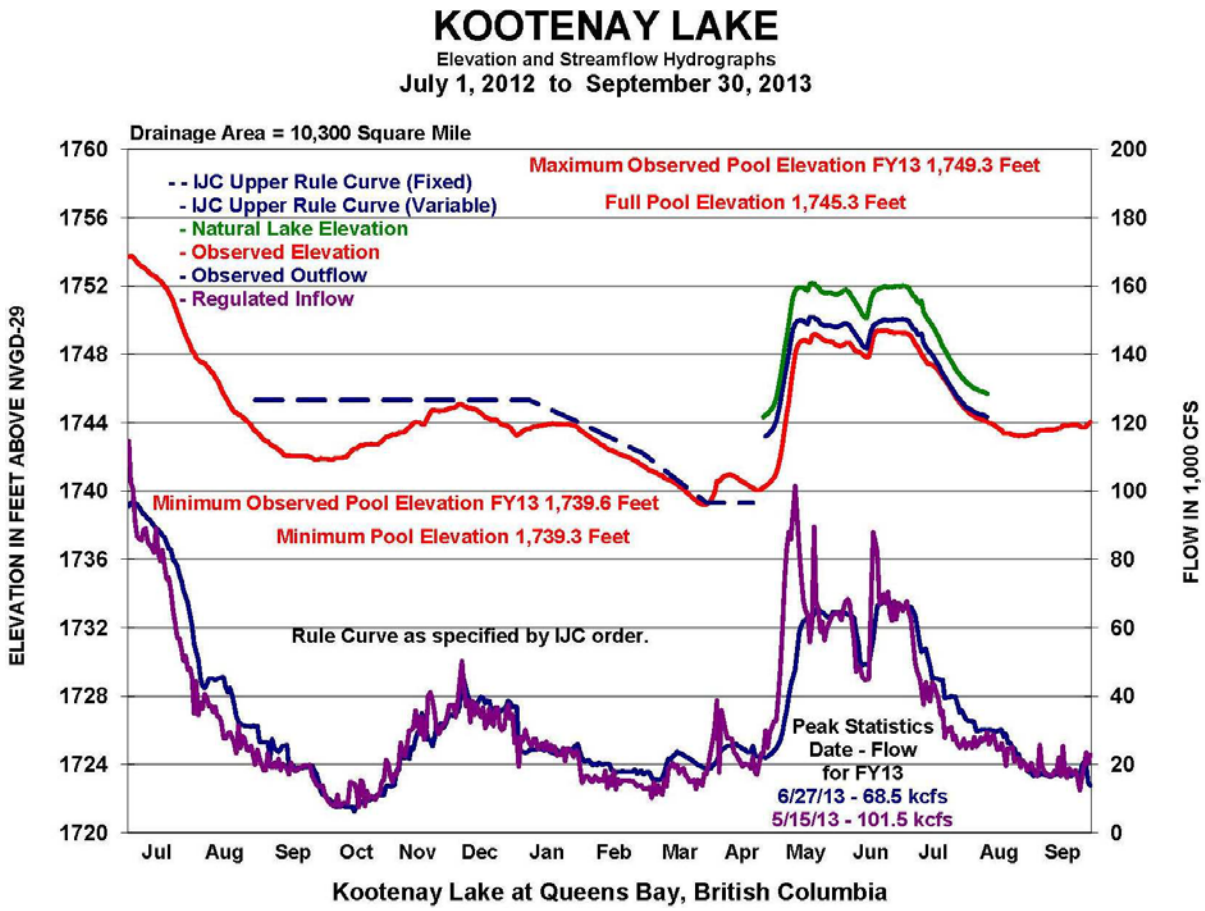


Chart 10: Columbia River at Birchbank

1 August 2012 – 30 September 2013

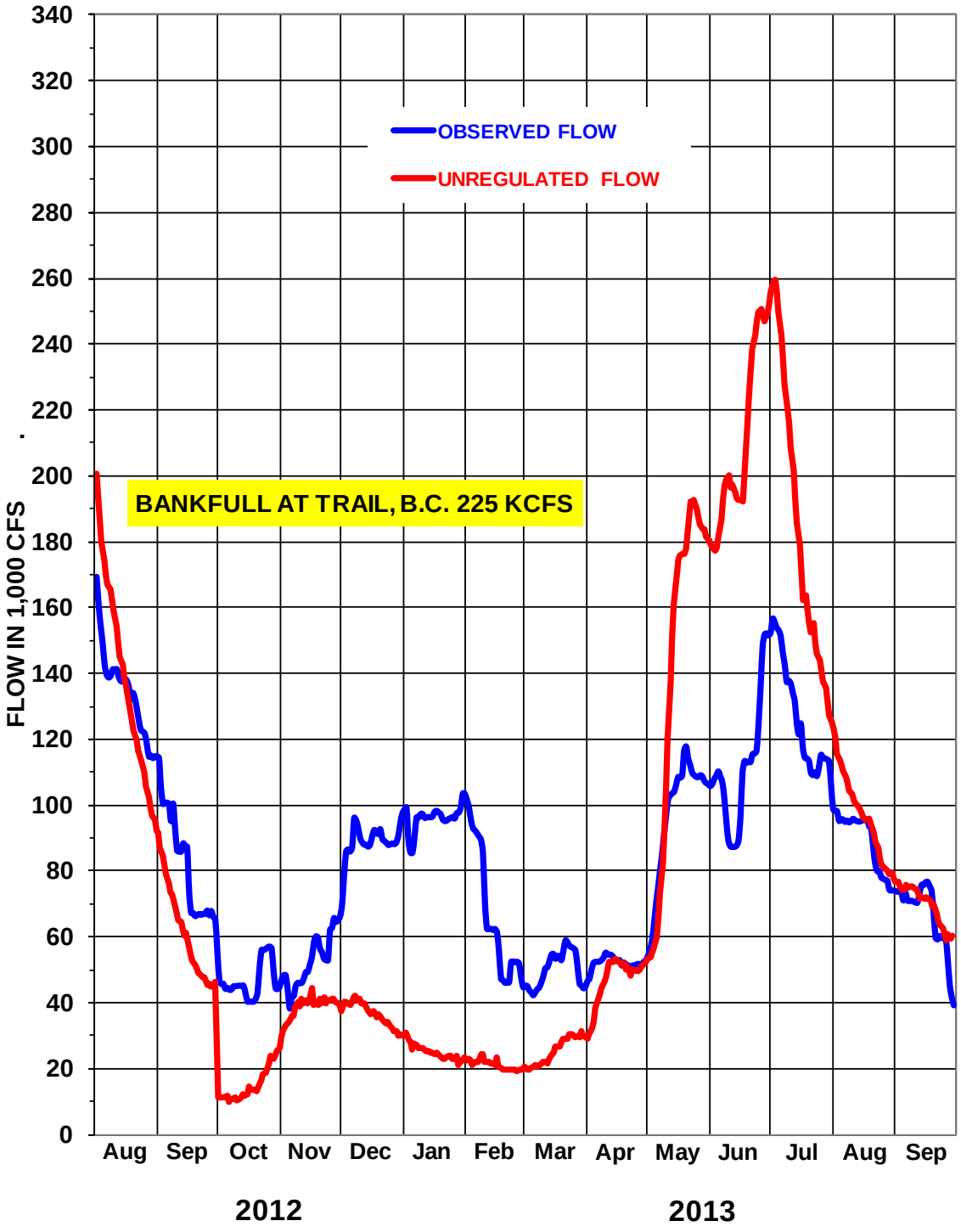


Chart 11: Regulation of Grand Coulee

1 July 2012 – 30 September 2013

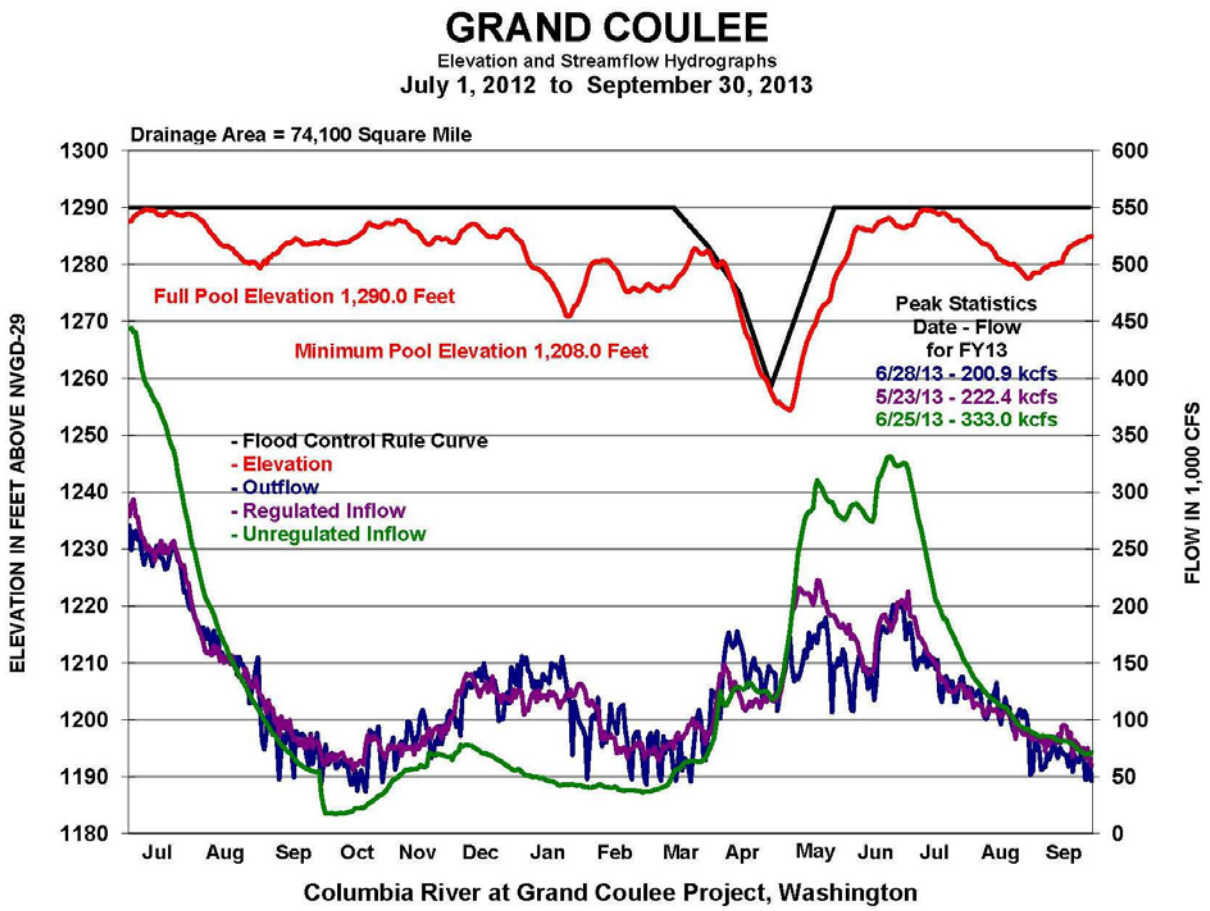


Chart 12: Columbia River at The Dalles

(Summary Hydrograph)

1 October 2012 – 30 September 2013

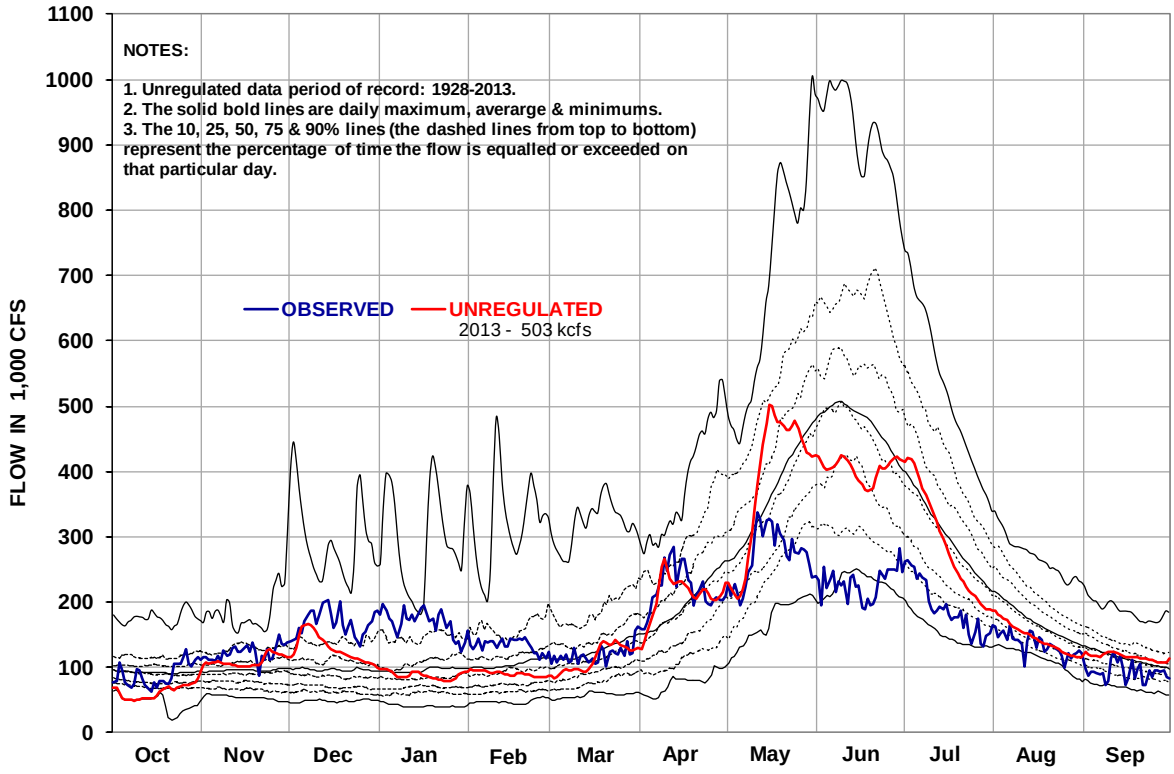


Chart 13: 2013 Columbia River at The Dalles Re-Regulation Plot

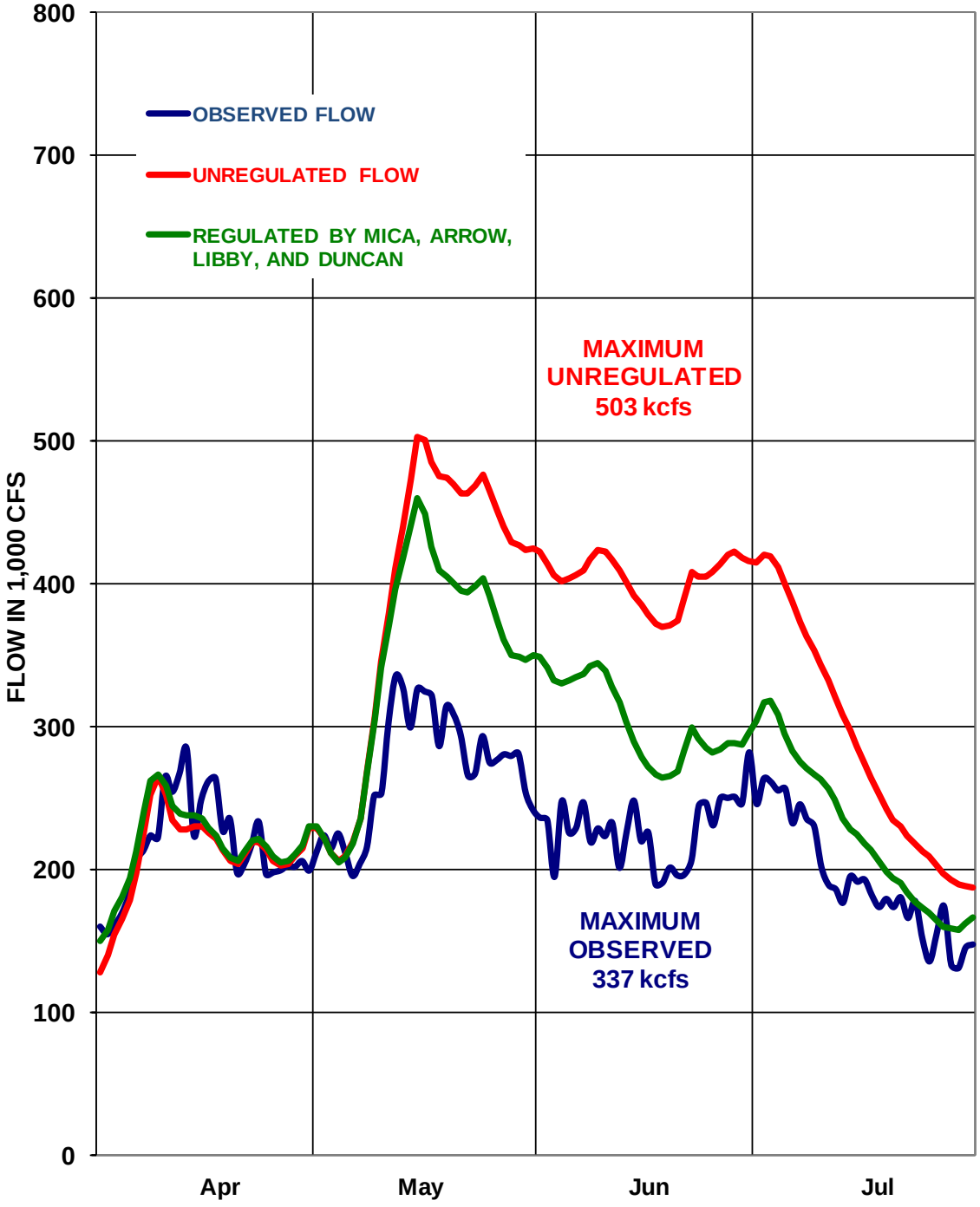
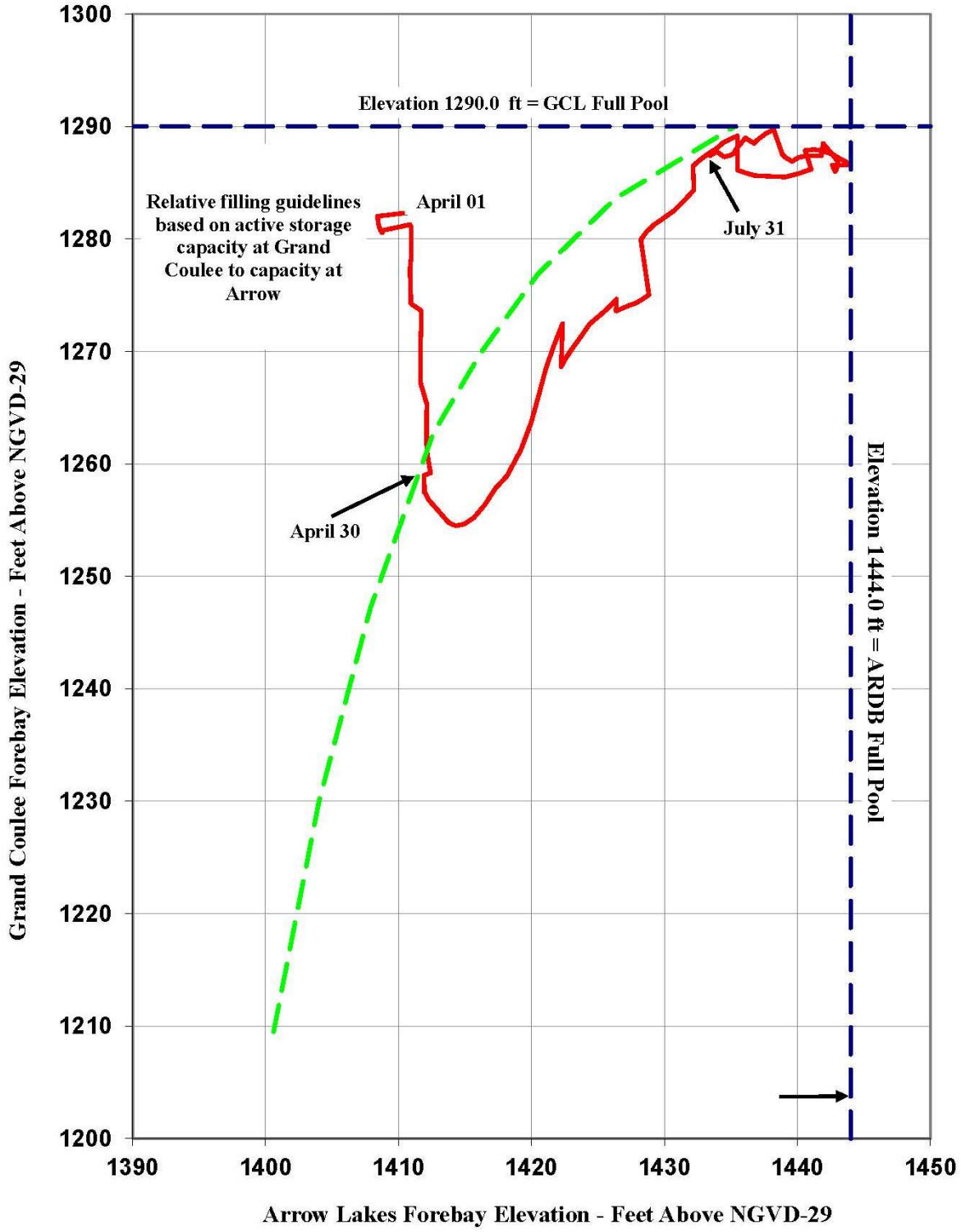



Chart 14: 2013 Relative Filling Arrow and Grand Coulee