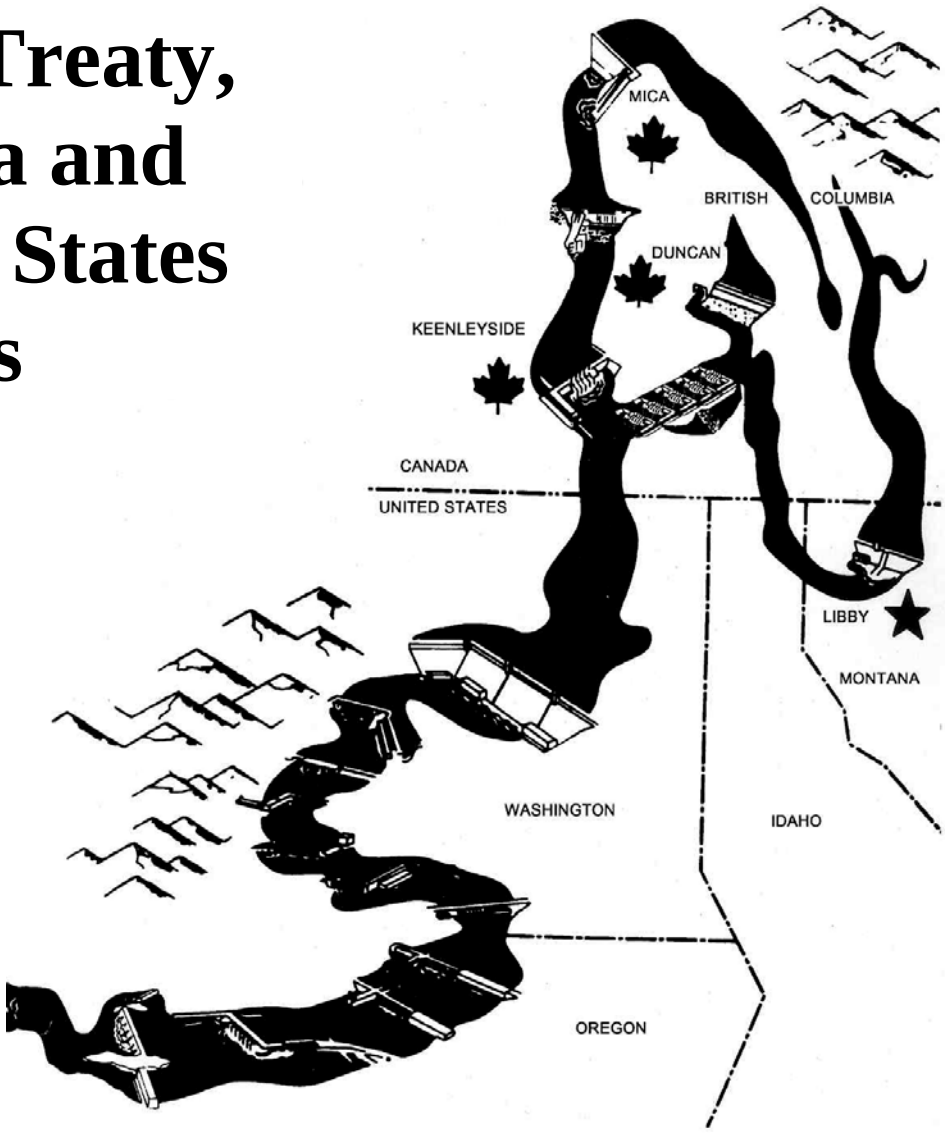
Annual Report of The Columbia River Treaty, Canada and United States Entities



1 August 2013 through
30 September 2014

2014 ANNUAL REPORT

OF THE

COLUMBIA RIVER TREATY

CANADA AND UNITED STATES ENTITIES

FOR THE PERIOD

1 AUGUST 2013 – 30 SEPTEMBER 2014

The Entities dedicate this Annual Report to the memory of Dr. Tony White who passed away unexpectedly in June 2014. Tony served as Secretary to the U.S. Entity from December 1995 until his retirement in April 2012. He was well known for his knowledge of Canadian politics, his pride in the Columbia River Treaty and his part in its implementation, and the excellent U.S.-Canada working relationship he cultivated over the years. Tony is deeply missed by his Treaty friends and colleagues.

For any feedback and comments:

Jason M. Ward, USACE
Jason.M.Ward@usace.army.mil

Pamela A. Kingsbury, BPA
pakingsbury@bpa.gov

Doug A. Robinson, B.C. Hydro
Douglas.Robinson@bchydro.com

EXECUTIVE SUMMARY

General

Overall, Water Year (WY) 2014 had relatively average runoff, marked by neutral El Niño Southern Oscillation conditions, with the April-August runoff across the Basin measured at The Dalles being 116.6 km^3 (cubic kilometers) (94.6 Million acre feet, Maf), or 108 percent of the 30 year average (1981 – 2010). Runoff in the Upper Columbia (101 percent of normal measured at Arrow) and Kootenai basins (113 percent of normal measured at Libby) was slightly above average while runoff in the Snake Basin was close to normal (99 percent of normal measured at Lower Granite). September 2013 was the wettest September on record in many parts of the upper basin, but was then followed by dry conditions for the remainder of the fall and the first half of winter due to a period of persistent high pressure in the atmosphere. As drought conditions were setting up, the second half of winter brought a dramatic snowpack recovery due to a change in the jet stream pattern bringing several winter storms and cold temperatures, allowing low to mid elevation snow to accumulate. The second half of winter brought large snow accumulations to high elevation parts of the basin and a dramatic recovery to above normal snowpack conditions, resulting in slightly above average April-August runoff and an unregulated peak flow at The Dalles of 16,827 m^3/s (cubic meters per second) (594 kcfs [thousand cubic feet per second]). Since 1960, WY 2014 ranks 22nd wettest out of 54 years of record in total April-August runoff as measured at The Dalles. For the 1 August 2013 through 30 September 2014 reporting period, the Canadian Treaty Projects were operated according to the 2013-2014 and the 2014-2015 Detailed Operating Plans (DOPs), the 2003 Flood Control Operating Plan (FCOP), and supplemental operating agreements as 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 and 2014 Supplemental BiOp for operation and maintenance of the Federal Columbia River Power System.

Entity Agreements

- Columbia River Treaty Short-Term Libby Agreement on Coordination of Project Operations (STLA), signed 27 September 2013.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan (AOP) and Determination of Downstream Power Benefits for Operating Year 2018-2019, signed 10 December 2013.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan (DOP) for Canadian Storage 1 August 2014 through 31 July 2015, signed 16 June 2014.

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 Canadian Storage for Nonpower Uses for 1 December 2013 through 31 July 2014, signed on 22 November 2013.

System Storage

The 2013-2014 operating year began on 1 August 2013 with the Canadian Treaty storage at 18.9 km^3 (15.4 Maf), or 99.1 percent full. Canadian Treaty storage drafted to a minimum of 4.7 km^3 (3.8 Maf), or 24.4 percent full on 16 April 2014, and refilled to 18.7 km^3 (15.1 Maf), or 97.6 percent full, on 31 July 2014. Canadian Treaty reservoirs operated in proportional draft mode during the second half of August 2013 and again during October-December to meet Treaty firm loads. Throughout the operating year, composite Canadian Treaty storage was very close to the TSR study composite storage, plus any operations implemented under mutually agreed upon Supplemental Operating Agreements (SOAs) including the Libby Coordination Agreement (LCA), Short Term Libby Coordination Agreement (STLA), and the Nonpower Uses Agreement. Exceptions occurred in all periods due to inadvertent draft or storage which occurs routinely due to updated inflow forecasts or differences between forecast and actual inflows. Canadian Treaty storage began and ended the operating year close to the DOP storage levels specified by the TSR study.

Under the terms of the LCA, B.C. Hydro exercised 0.07 km^3 (28 ksfd) of storage in late September and early October 2013 to refill the provisional draft that had been carried over from the previous operating year. In November and December 2013, B.C. Hydro exercised 0.45 km^3 (182 ksfd) of STLA provisional draft. In March 2014, 0.24 km^3 (98 ksfd) of the draft was returned, leaving an outstanding provisional draft account balance of 0.21 km^3 (84 ksfd) below TSR-specified levels.

As in past years, the CRTOC negotiated a Nonpower Uses Agreement, for mutual benefits in both countries, in order to manage Arrow Reservoir outflows and to improve conditions for fish in both countries. Under provisions of that agreement, the U.S. Entity stored 1.23 km^3 (504 ksfd) of flow augmentation water during January 2014. Operation under the agreement helped to manage flows downstream of Hugh Keenleyside Dam for Canadian whitefish and trout spawning protection during the January through June period. The flow augmentation water was subsequently released during July 2014 to help meet U.S. salmon flow objectives. From January until the end of July 2014, Canadian storage remained above TSR-specified levels.

The January 2014 water supply forecast for the Columbia River above The Dalles for January through July was 118.5 km^3 (96.1 Maf), or 95 percent of the 1981–2010 average. After the water supply forecast dropped to 98.7 km^3 (80.0 Maf) in February, or 79 percent of the 1981-2010 average, the spring water supply forecasts at The Dalles increased as the water year developed. By the June 2014 forecast, the runoff prediction had increased to 132.8 km^3 (107.7 Maf), or 106 percent of the 1981-2010 average. The actual January through July runoff for the Columbia River above The Dalles was 133.3 km^3 (108.1 Maf), or 107 percent of the 1981-2010 average.

Operations of the three Canadian reservoirs — Mica, Arrow, and Duncan — and the Libby Reservoir in the United States are illustrated in Section VIII as Charts 5 through 8 for the 14-month period from 1 August 2013 to 30 September 2014. The hydrographs show actual reservoir levels (Storage Curve) and key rule curves that govern the operations of Treaty storage. The Flood Risk Management Rule Curve specifies maximum month-end reservoir

levels which will permit timely evacuation of the reservoir to mitigate potentially high inflows from precipitation and snowmelt events. The Critical Rule Curve shows minimum end-of-month reservoir levels, which should be maintained to enable firm power demands to be met under the most adverse water supply conditions. The Variable Refill Curve shows the reservoir elevations necessary to ensure refilling of the reservoir by the end of July with a reasonable degree of confidence.

Treaty Project Operations

MICA (Kinbasket Reservoir)

The Mica (Kinbasket) Reservoir reached a maximum elevation in 2013 of 754.63 m (2475.8 ft), 0.25 m (0.8 ft) above normal full pool on 16 September 2013. B.C. Hydro sought and received permission from the B.C. Comptroller of Water Rights to surcharge the reservoir by 0.30 m (1.0 ft), up to 754.68 m (2476.0 ft) on an interim basis for power and flood risk management purposes. In addition, B.C. Hydro requested and the Corps approved a deviation to the Kinbasket Reservoir flood control curve for 31 October 2013 to minimize Mica spill while continuing to provide the required CRT flood risk management operation. B.C. Hydro utilized this storage flexibility to manage Kinbasket Reservoir operations during an ongoing lengthy powerhouse upgrade project that significantly reduced generation capacity during the summer of 2013, combined with well above normal inflows in September due to a large rainfall event. The reservoir was drawn down during the fall and winter to meet electrical demands and to prepare for normal spring runoff. The reservoir reached a minimum level of 724.78 m (2377.9 ft) on 25 April 2014, 1.98 m (6.5 ft) higher than the 2013 minimum level.

From mid-May through early July, Mica generation was reduced to near-minimum, as is normal during this period, in response to lower electrical demands in the summer and must-run generation elsewhere in the system. Generation was increased across mid July/August to meet market opportunities and manage the reservoir spill risk. Freshet inflows into Kinbasket Reservoir were close to normal during the spring and summer of 2014. The reservoir filled to a

maximum level of 753.89 m (2473.4 ft) on 2 September 2014, 0.49 m (1.6 ft) below normal full pool.

KEENLEYSIDE (Arrow Lakes Reservoir)

The Arrow Lakes Reservoir reached a maximum level of 439.99 m (1443.5 ft), or 0.14 m (0.5 ft) below full pool, on 3 July 2013. Arrow Lakes Reservoir reached a minimum level of 427.06 m (1401.1 ft) on 31 January 2014. By comparison, in the previous year, the Arrow Lakes Reservoir reached a minimum level of 427.93 m (1404.0 ft) on 13 February 2013. As basin inflows increased from snowmelt runoff during May through early July, the reservoir filled rapidly towards its Treaty Flood Risk Management level (upper rule curve), reaching a maximum level of 439.09 m (1440.6 ft), or 0.9 m (3.4 ft) below full pool, on 3 July 2014. Arrow Reservoir then drafted across the summer months reaching 433.7 m and 432.9 m (1422.8 ft and 1420.4 ft) by 31 August and 30 September 2014, respectively.

DUNCAN (Duncan Reservoir)

The Duncan Reservoir refilled to 576.65 m (1891.9 ft), or 0.04 m (0.1 ft) below normal full pool, on 8 August 2013. During the remainder of that month, Duncan Reservoir was operated to target a reservoir level of 575.5 m (1888 ft) on 1 September 2013. From September 2013 through April 2014, Duncan Reservoir was operated to supplement inflows into Kootenay Lake, to provide spawning and incubation flows for fish downstream in the Duncan River, and to meet Treaty Flood Risk Management requirements. As in most years, the reservoir was drafted to near empty in late April or early May. Duncan Reservoir reached its licensed minimum level, 546.87 m (1794.2 ft), on 25 April 2014. By comparison, the reservoir reached a similar minimum level of 546.92 m (1794.4 ft) on 26 April 2013. The reservoir discharge was reduced to its minimum of 3.0 m^3/s (0.1 kcfs) in late May to initiate reservoir refill. Releases from Duncan Reservoir were held at minimum until early July, when discharges were gradually increased to manage the rate of reservoir refill. The Duncan River discharge at the gage below the Lardeau River confluence (DRL) peaked at 299 m^3/s (10.6 kcfs) on 18 May 2014. By 31 July 2014, the Duncan Reservoir level reached 576.40 m (1891.1 ft) and the reservoir level peaked at 576.53 m (1891.5

ft), or 0.15 m (0.5 ft) below full, on 13 August 2014. Duncan Dam discharges were adjusted during August to target a reservoir level of 575.5 m (1888 ft +/- 1 ft) on 1 September 2014.

LIBBY (Koocanusa Reservoir)

Lake Koocanusa ended July 2013 at elevation 748.1 m (2454.4 ft). The project was drafted to elevation 746.5 m (2449.1 ft) at the end of August 2013, with outflows reduced gradually from 396.4 m^3/s (14 kcfs) to the bull trout minimum of 226.5 m^3/s (8 kcfs) over the final week of August. To assist with the continuing habitat restoration work in the Kootenai River, the Libby outflow was reduced to 169.9 m^3/s (6 kcfs) during the first week of September, and reduced again to 113.3 m^3/s (4 kcfs) for the month of October. The final April – August 2013 inflow volume to the project was 8.9 km^3 (7.2 MAF), or 122 percent of normal (1981 – 2010, 30 year normal).

The December 2013 water supply forecast for April-August 2014 runoff came in at 6.8 km^3 (5.5 MAF), or 94 percent of average, which set the end of December FRM elevation to 739.6 m (2426.6 ft). Subsequent forecasts ranged from 6.4 to 8.5 km^3 (5.2 to 6.9 MAF), with a May 2014 forecast of 8.6 km^3 (7.0 MAF), or 119 percent of average. Libby was drafted to a minimum elevation of 727.3 m (2386.0 ft) on 3 May 2014. Libby refill operations can begin as early as ten days prior to the ICF date but refill began on the ICF date of 9 May in 2014. Libby outflow was held at 453.1 m^3/s (16 kcfs) until 16 May, when the first of two discharge peaks was released for sturgeon flow augmentation. Powerhouse capacity was released through 23 May 2014; flows were then decreased to 509.7 m^3/s (18 kcfs) for one week, followed by an additional week at powerhouse capacity through 9 June. Outflow was then decreased gradually to control refill, with the reservoir elevation peaking at 747.7 m (2453.1 ft) on 23 July 2014. By 3 August 2014, the outflow was decreased to the summer bull trout minimum of 254.8 m^3/s (9 kcfs), which was held through the end of the month. The final April – August 2014 inflow volume to the project was 8.2 km^3 (6.7 MAF), or 113 percent of normal (1981 – 2010, 30 year normal). In September, the outflow of 254.8 m^3/s (9 kcfs) was continued until the final days of the month when the outflow was transitioned to the September bull trout minimum of 169.9 m^3/s (6 kcfs). The reservoir elevation at the end of September was 746.0 m (2,447.4 ft).

Treaty Benefits

Flood Risk Management Operations

Columbia River Basin projects were operated according to the May 2003 Flood Control Operating Plan. The 2014 water supply forecasts averaged slightly above normal across the Columbia River Basin except for the upper Snake River Basin, which was consistently below normal. The regulated peak flow at The Dalles, Oregon, was 10,129 m^3/s (357.7 kcfs) on 27 May 2014, and the unregulated peak flow was estimated at 16 827 m^3/s (594.3 kcfs) on 30 May 2014. The peak stage observed at Vancouver, Washington, was 3.5 m (11.5 ft) on 28 May 2014, and the estimated peak unregulated stage was 6.48 m (21.25 ft) on 30 May 2014 while the flood stage is 4.88 m (16 ft).

Flood Risk Management Benefits

Water Year 2014 was a relatively quiet flood risk management season with near normal seasonal volumes and manageable runoff shapes. There was less late season rainfall than in the previous two years resulting in fewer local flood risk issues. Reservoirs throughout the Columbia River basin, including the Treaty projects, were drafted during the winter and spring in preparation for flood season. The actual runoff for the overall Columbia basin (U.S. and Canada combined) measured at The Dalles for January through July 2014 was 107% of normal. The peak regulated and estimated unregulated flows, and river stages are shown in the following tables:

Columbia River Streamflow at The Dalles, Oregon

Date	Peak Unregulated Flow Estimated m^3/s (cfs)	Date	Peak Regulated Flow m^3/s (cfs)
30 May 2014	16,827 (594,300)	27 May 2014	10,129 (357,700)

Columbia River Stage at Vancouver, Washington

Flood Stage is 4.9 meters (16.0 feet)

Date	Peak Unregulated Stage Estimated m(ft)	Date	Peak Regulated Stage m (ft)
30 May 2014	6.48 (21.25)	28 May 2014	3.5 (11.5)

Hydroregulation by Duncan and Libby projects limited the peak level of Kootenay Lake to 533.50 m (1750.3 ft) on 27 May 2014. Without regulation from those Treaty dams, the peak level would have been approximately 534.7 m (1754.3 ft). As documented in the 2003 Flood Control Operating Plan, flood damages commence at Nelson when Kootenay Lake elevation reaches 534.92 m (1755.0 ft). Duncan, Arrow, Mica and Libby projects limited the peak flow of the Columbia River at Trail, just upstream of Birchbank, British Columbia, to 3678 m^3/s (129.9 kcfs) on 8 July 2014. Absent the dams but with natural lake effects at Kootenay Lake, the flow would have been approximately 6201 m^3/s (~219 kcfs). For reference, the bankfull flow at Birchbank is estimated to be 6371 m^3/s (225 kcfs).

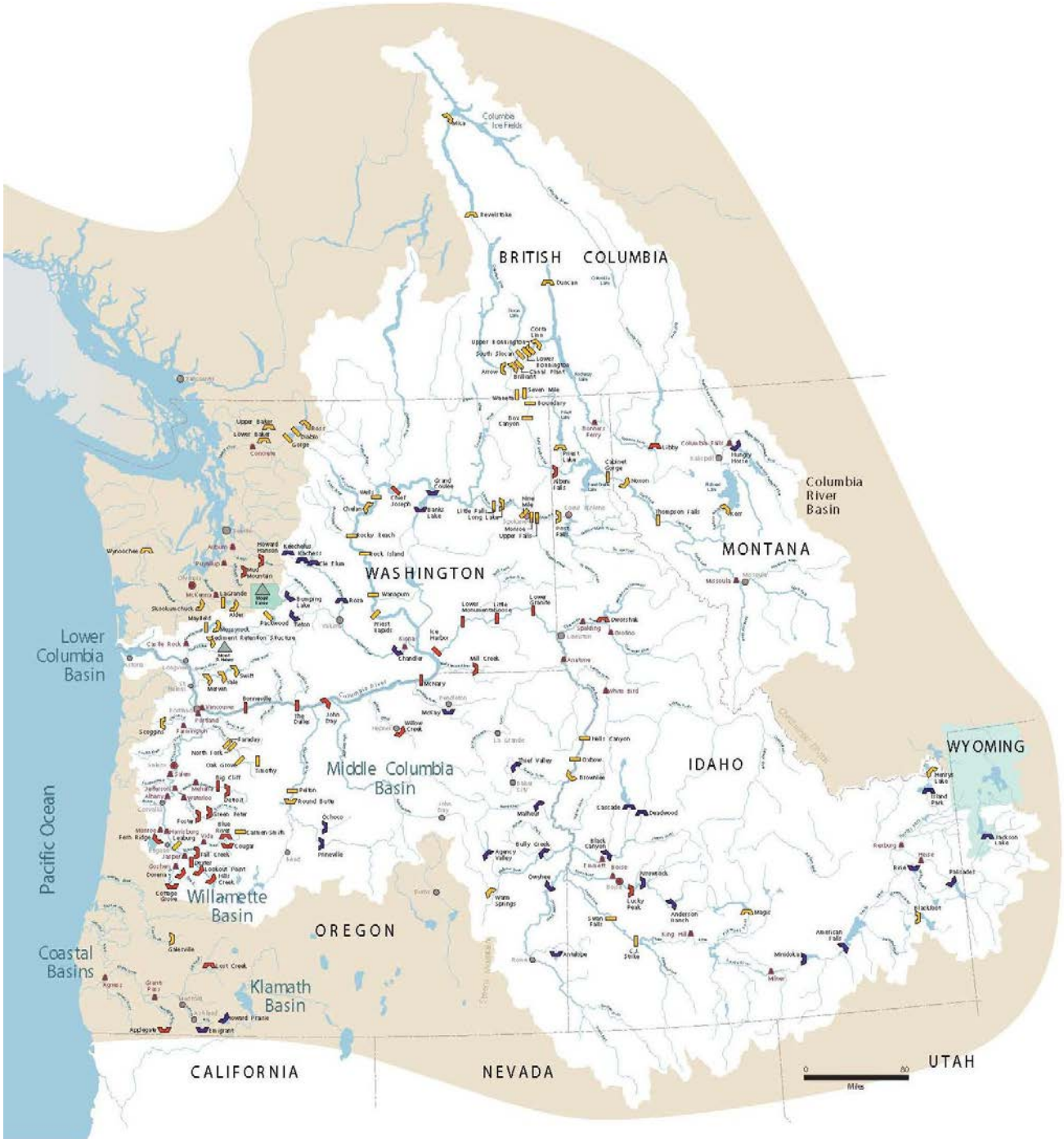
Power Benefits

A Determination of Downstream Power Benefits (DDPB) is computed in conjunction with the AOP. This computation represents the optimized generation from downstream U.S. projects that could have been produced by an optimized Canadian/U.S. system. The DDPB is prepared in accordance with the Treaty and Protocol, and other Entity Agreements. The Canadian Entitlement represents one-half of the DDPB. For the period 1 August 2013 through 31 July 2014, the Canadian Entitlement amount, before deducting transmission losses, was 505.5 aMW of energy, scheduled at rates up to 1336 MW. From 1 August 2014 through 30 September 2014, the amount, before deducting transmission losses, was 479.9 aMW of energy, scheduled at rates up to 1369 MW.

During the course of the 2013-2014 Operating Year, there were two curtailment events for Canadian Entitlement deliveries. These included a 28 megawatt hour (MWh) cut on 28 September 2013 due to transmission congestion, and a 149 MWh cut on 1 April 2014 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).

Actual U.S. power benefits from the operation of CRT storage are unknown and can only be roughly estimated. Treaty storage has such a large impact on the U.S. system operation that its absence would significantly affect operating procedures, non-power requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative. A rough estimate of the impact on downstream U.S. power generation during the 2013-2014 operating year, with and without the regulation of Canadian storage, based on the PNCA AER that includes minimum flow and spill requirements for U.S. fishery objectives, is 688 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 was reported by the Entities.

Columbia Basin Map



2014 Report of the Columbia River Treaty Entities
Table of Contents

EXECUTIVE SUMMARY i

General i
Entity Agreements ii
Columbia River Treaty Operating Committee Agreements ii
System Storage ii
Treaty Project Operations iv
Treaty Benefits vii
Columbia Basin Map x
Table of Contents xi

I – INTRODUCTION 1

II - TREATY ORGANIZATION 3

Entities 3
Entity Coordinators & Secretaries 4
Columbia River Treaty Operating Committee 5
Columbia River Treaty Hydrometeorological Committee 7
Permanent Engineering Board 10
PEB Engineering Committee 12
International Joint Commission 12

III - OPERATING ARRANGEMENTS 14

Power and Flood Control Operating Plans 14
Assured Operating Plans 15
Determination of Downstream Power Benefits 16
Canadian Entitlement for the Operating Year 16
Detailed Operating Plans 17
Libby Coordination Agreement 18
Entity Agreements 18
Columbia River Treaty Operating Committee Agreements 19
Long Term Non-Treaty Storage Agreement 19

IV - WEATHER AND STREAMFLOW 20

Columbia Basin Weather 24
Streamflow 24
Columbia River Unregulated Streamflow 25
Seasonal Runoff Forecasts and Volumes 26
Historic Seasonal Runoff Forecasts and Volumes (km^3) 27
Historic Seasonal Runoff Forecasts and Volumes (Maf) 28

V - RESERVOIR OPERATION 29

General 29
Canadian Storage Operation 29
Mica Reservoir 30
Revelstoke Reservoir 31

Arrow Reservoir 32
Duncan Reservoir 33
Libby Reservoir 35
Kootenay Lake 36

VI - FLOOD RISK MANAGEMENT AND POWER ACCOMPLISHMENTS 37

General 37
Flood Risk Management 38
Canadian Entitlement and Downstream Power Benefits 40
2014/2024 Review 42
Power Generation and Other Accomplishments 43

VII – TABLES 48

Table 1M (metric): Unregulated Runoff Volume Forecasts Cubic Kilometers 48
Table 1: Unregulated Runoff Volume Forecasts Million Acre-feet 48
Table 2M (metric): 2014 Mica Reservoir Variable Refill Curve 49
Table 2: 2014 Mica Reservoir Variable Refill Curve 50
Table 3M (metric): 2013 Arrow Reservoir Variable Refill Curve 51
Table 3: 2014 Arrow Reservoir Variable Refill Curve 52
Table 4M (metric): 2014 Duncan Reservoir Variable Refill Curve 53
Table 4: 2014 Duncan Reservoir Variable Refill Curve 54
Table 5M (metric): 2014 Libby Reservoir Variable Refill Curve 55
Table 5: 2014 Libby Reservoir Variable Refill Curve 56
Table 6: Computation of Initial Controlled Flow 57

VIII - CHARTS 58

Chart 1: Pacific Northwest Monthly Temperature Departures 58
Chart 1 A: Pacific Northwest Monthly Precipitation Departures 60
Chart 2: Seasonal Precipitation Columbia River Basin 62
Chart 3: Columbia Basin Snowpack 63
Chart 4: Accumulated Precipitation for WY 2014 64
Chart 5: Regulation of Mica 65
Chart 6: Regulation of Arrow 66
Chart 7: Regulation of Duncan 67
Chart 8: Regulation of Libby 68
Chart 9: Regulation of Kootenay Lake 69
Chart 10: Columbia River at Birchbank 70
Chart 11: Regulation of Grand Coulee 71
Chart 12: Columbia River at The Dalles (Summary Hydrograph) 72
Chart 13: 2013 Columbia River at The Dalles Re-Regulation Plot 73
Chart 14: 2014 Relative Filling Arrow and Grand Coulee 74

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

CE……...Canadian Entitlement

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 R. 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

STLA…….....Columbia River Treaty Short-Term Libby Agreement on Coordination of Project Operations

TSR……Treaty Storage Regulation

U.S. .....United States

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

VarQ.....Variable flow flood risk management

VRC .....Variable refill curves

VRCLL .....Variable Refill Curves Lower Limits

WUP.....Water Use Plan

WY .....Water Year

Unit Conversions

Distance

1 km = 3280.839895 ft

1 m = 3.280839895 ft

Volume

1 m^3 = 35.314666721 ft^3

1 km^3 = 35314666721 ft^3

1 km^3 = 0.810713194 Maf

1 hm^3 = 0.000810713 Maf

1 hm^3 = 0.81071319 kaf

1 hm^3 = 0.40873 ksfd

1 ksfd = 1.98347 kaf

Flow

1 m^3/s = 35.31466672 cfs

I – INTRODUCTION

This annual Columbia River Treaty Entity Report is for the Water Year (WY) 2014, 1 October 2013 through 30 September 2014, 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 2013 through 31 July 2014. Also described are the power and flood risk management effects downstream in Canada and the United States (U.S.). This report is the 48th 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 risk management and increasing hydroelectric power generation in Canada and the U.S. 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 Commander of the Northwestern Division, U.S. Army Corps of Engineers (USACE). These 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.

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 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 risk management 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 risk management 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 5 February 2014 in Portland.

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

UNITED STATES ENTITY

Mr. Elliot Mainzer, Chairman*
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 Administrator on 27 January 2014.

** 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

Richard Pendergrass*
Acting 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

*Mr. Pendergrass was appointed Acting Coordinator on 29 January 2014 to replace the retiring Stephen Oliver.

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**
Pamela Kingsbury*, 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
Birgit Koehler**, BPA	Alaa Abdalla, B.C. Hydro

* Ms. Pamela Kingsbury was appointed to replace Mr. Rick Pendergrass on 29 January 2014.
** Ms. Tina Ko was appointed to replace Ms. Kingsbury on 29 January 2014; Ms. Birgit Koehler was appointed to replace Ms. Ko on 30 April 2014.

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 2018/19 AOP/Determination of Downstream Power Benefits (DDPB);
- Completed the 1 August 2014 through 31 July 2015 DOP;
- Completed one supplemental operating agreement for Canadian storage;
- Completed a Mica FRM deviation request for October 2013, as approved by USACE;
- Implemented the Libby Coordination Agreement (LCA) including the July 2014 update to the Libby Operating Plan, scheduling of Arrow provisional draft, delivery of one average MW of power, and analysis and monitoring of Canadian power effects from VarQ flood risk management operation at Libby Reservoir;
- Completed the Libby Operating Plan for 2014-2015, July 9, 2014;
- Briefed the PEBCOM on Entity activities, and completed the 2013 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 the PEBCOM meeting, November 2014. Pictured are (L to R, back row), Trevor Downen, Jim Barton (U.S. Alternate Chair), Robyn MacKay, Bill Proctor (member), Kelvin Ketchum (Canadian Chair), Alaa Abdalla (member), Rob Diffely ,(L to R, front row), Birgit Koehler (member), Peggy Racht, Karl Kanbergs, Doug D. Robinson, Pam Kingsbury (U.S. Alternate Chair), Doug A. Robinson (Secretary), Jeremy Benson

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	**CANADIAN SECTION**
Ann McManamon, BPA Co-Chair	Stephanie Smith, B.C. Hydro, Chair
Peter Brooks, USACE Co-Chair	Adam Gobena, B.C. Hydro, Member

The CRTHC met twice during the 1 August 2013 – 30 September 2014 period:

Meeting 73: 29-30 April 2014, B.C. Hydro
Meeting 74: 12-13 August 2014, USACE

The 2013 CRTHC Annual Report was completed in December 2013 and distributed prior to the annual PEB meeting.

Forecasting

The CRTHC spent a considerable amount of time working with the Corps' Seattle District (CENWS) in their preparation of an updated Libby April – August seasonal volume forecast. The Kootenay River experienced three consecutive years of a combination of rising April –August forecasts and late season (May and June) above-average rainfall, including record June precipitation in 2012. Also, the climate indices in the existing forecast procedure were providing spurious and contradictory information to the forecast. The CRTHC and CENWS agreed that the focus of the update should be to review the climate indices, extend the period of record back to 1984, and include 2011-2013 in the forecast training period. The tendency might be to treat 2012 as an outlier; but, because late season rainfall happened in three consecutive years, the CRTHC believed it important that those types of years be included in the period of record. On 29 August 2014, the CRTHC recommended to the CRTOC that the new forecast procedure be approved for implementation. The CRTOC approved the forecast procedure, and the decision was recorded in the 18 September 2014 minutes of the CRTOC.

The Northwest River Forecast Center (NWRFC) continues to produce water supply forecasts using the Ensemble Streamflow Prediction (ESP) procedure. In December 2013, the NWRFC announced that it would be adopting a 5-day short term weather forecast for its ESP products and discontinuing the 3-day short term weather forecast. This change brought them into alignment with other RFCs across the U.S. The CRTHC did not have a reason to accept or reject the NWRFC proposal, and agreed to use it for the basin-wide ESP volume forecasts for the upcoming season. During WY 2014, the CRTHC monitored the performance (at The Dalles and Libby) of the 5-day ESP for accuracy and timeliness and

found that it performed adequately. The CRTHC prepared a recommendation for the CRTOC with ESP 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 September 2014 CRTOC meeting, the CRTHC provided the recommendation for forecast dates (typically the 5th working day of the month) for the upcoming year; and the recommendation was approved by the CRTOC. The CRTHC will continue to monitor and evaluate the range of ESP forecast lead times to determine what best serves the needs of the Treaty.

Data Exchange

B.C. Hydro's FTP data server was relocated to a secure facility in Kamloops, B.C., and all agencies are obtaining B.C. Hydro data from that server. B.C. Hydro has also begun the transition to the use of the secure file transfer protocol (sFTP). Testing has begun with BPA's sFTP site, and will expand to include the Corps' sFTP server. Testing and implementation are expected to be complete in early WY 2015.

BPA identified some irregularities in how the SHEF-encoding was taking place in the Corps' database. BPA and the Corps will establish a list of stations that need attention and fix them within the first quarter of WY 2015

Stations

A number of years ago, B.C. Hydro and the Seattle District of the Corps reached an agreement for B.C. Hydro to install two water temperature gauges in Elk River at Fernie and Kootenay River at Fort Steele. The probes were provided by Corps, and BPA agreed to pay the operating costs for the sites (~$700/year each). This agreement has since expired, and at least one of the probes needs to be replaced. B.C. Hydro would like to authorize Water Survey of Canada to replace the probes with their own instruments (at B.C. Hydro's cost) to improve maintenance of the instruments. The Corps' Seattle District expressed a need to continue the gages. The new contract between BPA and B.C. Hydro for maintenance of the snow stations also includes these water quality stations. The stations are maintained by Water Survey of Canada under the direction of B.C. Hydro and funded by BPA.

Three new snow station sites were installed in B.C. during September 2014 under a cost-sharing agreement between B.C. Hydro and BPA. They are Wildcat Creek near Mistaya Lodge and Kicking Horse, Colpitti Creek near Sunbeam Lake, and Caribou Creek Upper near Vermont Creek. These three sites, plus one installed last year at Keystone Creek, are in the Upper Columbia drainage and are close to 2100 meters in elevation. .These stations provide much-needed high-elevation snowpack information in real-time in an area that has been historically inadequately covered. The CRTHC continues to add to and re-shape its station database for use primarily in monitoring station adequacy, tracking station changes, and visualization of basin coverage. A significant amount of metadata has been added; and all stations are placed in one of three categories: Treaty, supplemental, and informational. The CRTHC routinely reviews the basin gaging network for adequacy. At this time, the CRTHC believes that the station network is adequate for Treaty purposes.

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**
James C. Dalton, 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

* Mr. James Dalton assumed the role of PEB chair for the U.S. from Mr. Steve Stockton on 4 March 2014

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 operating plans or the FCOP, and, if appropriate, include recommendations for remedial action. Additionally, the PEB is to:

- Assist in reconciling differences that may arise between the Entities;
- Make periodic inspections and obtain reports, as needed, from the Entities to assure that CRT objectives are being met;
- Prepare an annual report to both governments and special reports when appropriate;
- Consult with the Entities in the establishment and operation of a hydrometeorological system; 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 4-5 February 2014 at BPA offices in Portland, Oregon. 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 partial solution for lost Canadian power revenue due to VarQ at Libby was developed between BPA and B.C. Hydro, the Columbia River Treaty Short-Term Libby Agreement (STLA) on coordination of project operations, and signed 27 September 2013. This was reported to the PEB at the February 2014 meeting. B.C. Hydro also reported that they are continuing to study the potential of dredging Grohman Narrows. A key request from the 2014 PEB / Treaty Entities meeting was for the CRTOC to work toward a plan for clarifying the surcharge procedures for the Libby project and Koocanusa Reservoir. The plan was developed and is projected to be completed prior to the FRM season of WY 2015.

PEB Engineering Committee

The PEB has established the PEBCOM to assist in carrying out its duties. The PEBCOM met with the Operating Committee on 23 October 2013 in Vancouver, British Columbia. 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

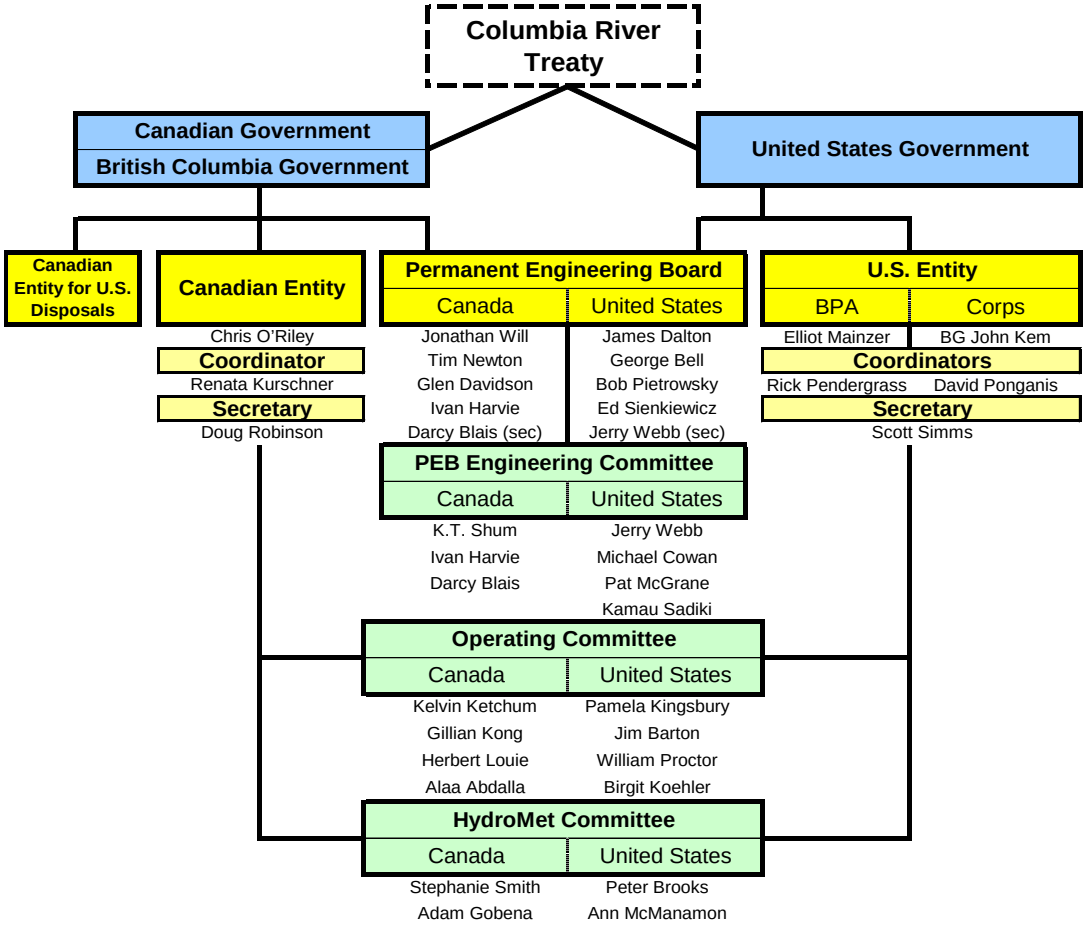
K.T. Shum, Member
Victoria, British Columbia

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 Lana Pollack, Acting Canadian Section Chair Gordon Walker, U.S. members Rich Moy and Dereth Glance, and the other Canadian member is 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 IJC Boards of Control west of the Continental Divide: the International Columbia River Board of Control, the International Osoyoos Lake Board of Control, and the International Kootenay Lake Board of Control (KLBC), which oversees the implementation of the 1938 IJC Order on Kootenay Lake.

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 risk management 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 risk management storage diagrams or any variation which the Entities agree will not reduce the desired aim of the flood risk management plan; and
3. Provides for the development of assured hydroelectric operating plans for Canadian storage for the 6th succeeding year of operation (i.e., 5 years in advance).

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 2013-2014 Operating Year from 1 August 2013 through 31 July 2014. The operation of Canadian storage was guided by the 2013-2014 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 2013-2014 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period from 1 August 2013 through 30 September 2014.

Assured Operating Plans

During the reporting period, the Entities completed the 2018-2019 AOP. An Entity agreement approving the 2018-2019 AOP was executed on 10 December 2013. The 2018-2019 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. This AOP used all three of the streamline procedures described in Appendix 6 of the Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage (POP) and is based on the 2017-2018 AOP/DDPB Hydroregulation studies.

The 2018-2019 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 in the 2018-2019 operating year. The ORCs were derived from CRCs, Assured Refill Curves, Upper Rule Curves (Flood Risk Management 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 Rule Curves conform to the 2003 FCOP and are used to define maximum reservoir levels for the operation of Canadian storage. The 2018-2019 AOP uses the 5.03/4.44 km^3 (4.08/3.6 Maf) Mica/Arrow flood risk management allocation. The CRCs are used to apportion draft below the ORCs when the TSR determines that additional draft is needed to meet the Coordinated System firm energy load carrying capability (FELCC). The second streamline procedure was used for the 2018-2019 AOP, and so operating criteria for this AOP are a direct carry-over from the 2017-2018 AOP.

During the reporting period, the Entities began to assemble the loads and resources assumptions and data for the 2019-2020 AOP. Recent AOP studies have shown that the amount of AOP surplus generating capacity is declining. When the AOP surplus capacity reaches zero, then capacity, rather than energy generation, becomes an important limiting factor in the AOP study, resulting in significant changes to study procedures. For this reason,

the CRTOC is doing a careful review of the 2019-2020 AOP load and resource assumptions and data, which will result in a delay in producing the 2019-2020 AOP.

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). For the 2018-2019 DDPB, the Entities agreed to use the third streamline procedure (Hydro energy reshaping for Steps II and III Studies) described in Appendix 6 of the POP.

The total downstream power benefits as a result of the operation of Canadian storage for the 2018-2019 Operating Year were determined to be 2567.9 MW of dependable capacity, and 945.0 average annual MW of usable energy. Therefore, the Canadian Entitlement (CE) to downstream power benefits for the 2018-19 operating year is 1284.0 MW of capacity (a 20.1 MW decrease from 2017-18) and 472.5 average MW (aMW) of energy (a 2.5 aMW decrease from 2017-18). The CE capacity reduction is caused by a slight increase in the critical period load factor as well as a smaller increase in the Step II critical period generation relative to the Step III critical period generation. The CE energy reduction 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 2013 through 31 July 2014, the Canadian Entitlement amount, before deducting transmission losses, was 505.5 aMW of energy, scheduled at rates up to 1336 MW capacity. From 1 August 2014 through 30 September 2014, the amount, before deducting transmission losses, was 479.9 aMW of energy, scheduled at rates up to 1369 MW capacity. The CE obligation was determined by the 2013-2014 and 2014-2015 AOP/DDPBs.

During the course of the 2013-2014 Operating Year, there were two curtailment events for CE deliveries. These included a 28 megawatt hour (MWh) cut on 28 September 2013 due to transmission congestion, and a 149 MWh cut on 1 April 2014 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).

Detailed Operating Plans

During the period covered by this report, the CRTOC used the DOP for 1 August 2013 through 31 July 2014, dated May 2013, and the DOP for 1 August 2014 through 31 July 2015, dated June 2014, 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 2013-2014 and 2014-2015 DOPs were based respectively on the 2013-2014 AOP and 2014-2015 AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects. The 2013-2014 and 2014-2015 AOPs included a flood risk management allocation of 4.44 km^3 (3.6 Maf) at Arrow and 5.03 km^3 (4.08 Maf) at Mica. The 2013-2014 DOP and 2014-2015 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 risk management 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 risk management curves and VRCs, and actual unregulated inflows for the previous month. The TSR and supplemental operating agreements defined the end-of-period draft rights for Canadian storage. The VRCs and flood risk management requirements, subsequent to 1 January 2014, were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby Reservoir for the 2013-2014 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

was 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, the STLA 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 2013-2014 Operating Year. The most recent Libby Operating Plan is dated 9 July 2014. Provisional draft operations under the LCA are discussed in Section VI. On 27 September 2013, the Entities signed a Short-Term Libby Agreement on coordination of Project Operations (STLA) to address, until 31 August 2015, issues raised by the Canadian entity regarding VarQ operations at Libby. The STLA provides the Canadian Entity additional flexibility to draft and store at Arrow reservoir. During the term that the STLA is in effect, Section 10 and Attachment C of the LCA are suspended. Other portions of the LCA shall remain in effect.

Entity Agreements

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

Date Signed by Entities	Description of Agreement
27 September 2013	Columbia River Treaty Short-Term Libby Agreement on Coordination of Project Operations (STLA)
10 December 2013	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2018-2019.
16 June 2014	Columbia River Treaty Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2014 through 31 July 2015.

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
22 November 2013	Columbia River Treaty Operating Committee Agreement on Operation of Canadian Storage for Nonpower Uses for 1 December 2013 through 31 July 2014	Detailed Operating Plan 1 August 2013 through 31 July 2014, dated 31 May 2013

In addition to the Operating Committee agreement listed above, the U.S. Entities (BPA and/or USACE) and B.C. Hydro developed the following bilateral agreements:

- Agreement on use of Non-Treaty Storage for July and August 2013 providing mutual power and non-power benefits for the period 1 July 2013 through 30 August 2013, agreed upon 3 July 2013. The agreement was extended to 6 September 2013 as agreed on 30 August 2013 to avoid overfilling composite Treaty Storage at a maximum of 19.1 km^3 (15.5 Maf).
- A Flood risk management deviation request, and approval by USACE, for 0.25 km^3 (0.2 Maf) of flood storage space at Kinbasket (Mica) Reservoir on 31 October, agreed upon 7 October 2013.

In addition, there was also a verbal agreement between BPA and B.C. Hydro that covered the storage, and subsequent release, of NTSA water during the period 31 May through 31 August 2014, providing mutual power and non-power benefits during the period.

Long Term Non-Treaty Storage Agreement

The Long Term NTSA, executed in April 2012, was utilized by BPA and B.C. Hydro to reduce high Arrow outflows in early July 2013, and release this water instead during August-September 2013. In addition, BPA and B.C. Hydro used the provisions of the NTSA for

power purposes during the winter period and reshaped flows from spring into summer during the fish passage season.

In accordance with the Entity agreement that approved the 2012 NTSA contract between BPA and B.C. Hydro, the CRTOC monitored the storage and release operations under the Agreement throughout the operating year to ensure they did not adversely impact the operation of CRT storage required by the DOPs.

IV - WEATHER AND STREAMFLOW

Although precipitation was slightly below average for the 2013-14 water year, the year was punctuated by one of the sharpest weather swings observed in many years. The swing, which occurred during the second half of the winter, led to rapid and sustained snowpack gains across the entire basin, and turned what was initially becoming a basin-wide drought into above average spring and annual runoff in the Columbia River Basin.

For the second consecutive winter in a row, sea surface temperatures in the tropical Pacific were near the long term average. Thus, the El Niño/Southern Oscillation was not a key player in regional weather. However, an unusually persistent, intra-seasonal blocking pattern and strong polar vortex over Hudson Bay tended to lock the jet stream in place for long periods of time for much of the year. Just before the start of the water year, the evolving blocking pattern locked into a position favoring wet conditions over the Columbia basin. Flowing off the west Pacific, the jet stream guided a series of strong storm systems across the region during September, 2013. Rare September flow spikes in some headwaters in Montana, Washington, and British Columbia were observed as the Columbia Basin had its wettest September since reliable basin-average records were kept starting in 1976-77.

Then the jet stream locked into a position which would remain essentially unchanged through the last week of January 2014. During this period, the jet stream generally flowed across Alaska and the Yukon Territory before diving south into the central and eastern United States. That left a persistent ridge along the West Coast which blocked all but the strongest Pacific frontal systems from crossing the Columbia Basin. Systems that did break through the block either weakened before crossing the Cascade mountains, or were forced over the top of the ridge and clipped the upper Columbia, Kootenay and Flathead Basins. By

mid-January, concerns for a basin-wide drought emerged as accumulated precipitation deficits continued to build. Only 49% of the usual precipitation fell between 1 October 2013 and 31 January 2014, making it the driest start to the water year since at least 1977 (Figure 1). Temperatures initially held near or slightly below average which allowed whatever precipitation that did fall to build a modest snowpack. However, as the ridge strengthened in January, temperatures rose well above average across the Basin and began to deplete already meager lower elevation snowpacks (Figure 2).

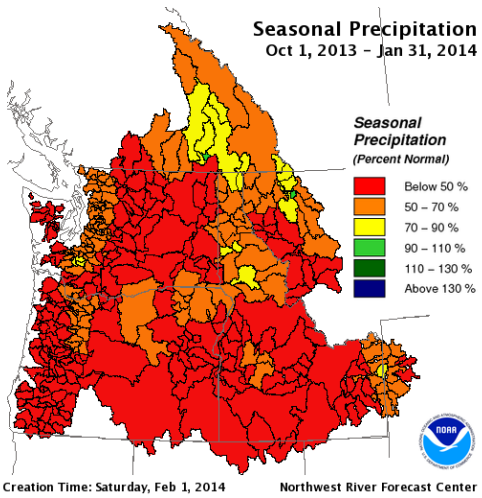


Figure 1: Basin precipitation relative to average, October, 2013-January 2014

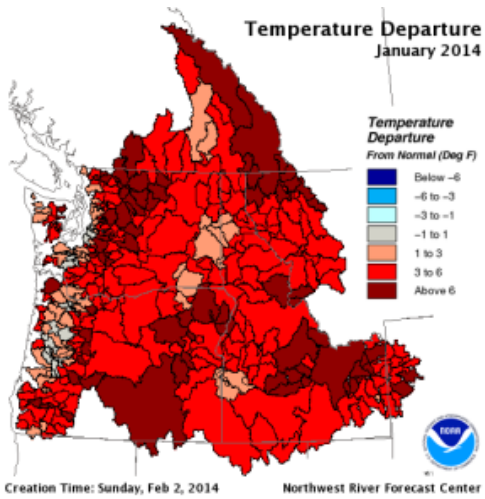


Figure 2: Basin temperatures, January, 2014.

As February began, though, a subtle but critical pattern change commenced which resulted in one of the stormiest late-winter periods on record in the Columbia Basin. Instead of coming directly off Alaska and bypassing the region to the east, the jet stream realigned just enough to start flowing off the north Pacific. Not only did that open the door for very moist and windy storm systems to move off the Pacific, but it allowed the now intense Arctic air mass over central and southern Canada to expand into the Columbia Basin. Temperatures plummeted to record lows several times across the northern two-thirds of the basin in what became the coldest month in the region since January 2013. Above Grand Coulee, basin average temperatures were an astounding 4.0°C/7.4°F below average for the entire month of February (Figure 3). Snow levels dropped to sea level twice during the first half of February, which combined with incoming Pacific storms resulted in crippling snowstorms in

Vancouver, Seattle, Portland, and Spokane. Meanwhile, in the high mountains of the upper Columbia, western Montana and central Idaho, snow fell at the rate of a meter a day during three separate storms on 5-7 February, 10-12 February, and 17-19 February. While the Arctic air mass modified somewhat in March, the jet stream remained aimed at the region from the cold north Pacific, and this kept the low elevation rain falling and mountain snows accumulating (Figure 4). In a stunning turn of events after such a dry start to the water year, the region experienced its second wettest February since 1977, followed by its wettest March on record – smashing the "Miracle March" basin average record in 2012 by 20mm (0.80 inches).

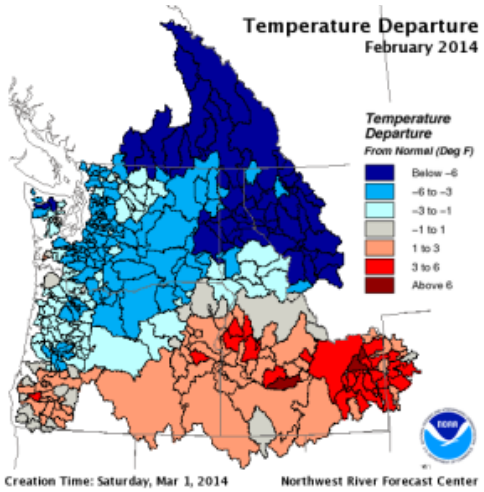


Figure 3: Basin temperatures, February 2014

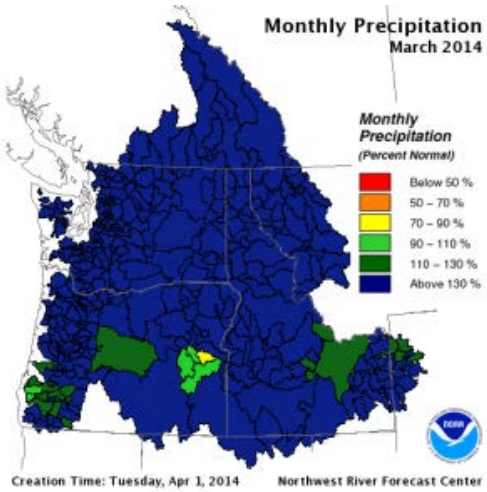


Figure 4: Basin Precipitation relative to average, March 2014.

As fears of a drought were replaced by new fears of spring flooding, the jet stream shifted back to the north by early April, and a new but weaker blocking ridge developed over California. This ridge ended any hopes of drought recovery south of the region, but it allowed cool air to hold over the Columbia Basin and allowed cold fronts to move off the Pacific. This helped to build a little more snowpack prior to the start of the spring runoff in the northern half of the basin. By May, temperatures slowly warmed and the region began to dry out as the ridge once again expanded north. The result was a very orderly spring runoff with no major flood spikes despite a snowpack which by the end of April was around 122% of the long-term normal in the Columbia Basin.

The large swings in weather conditions, though, were not quite over. The persistent ridge which developed in April and expanded north along the west coast in May strengthened and shifted inland into the heart of the basin by early July. Not only did this amplify the usual dryness across the basin, but it allowed persistent heat to take hold for much of July and August. This was enough for the some areas west of the Cascades to have one of their hottest June-August periods since the 1930s. The persistent ridge finally progressed slightly east to the Continental Divide in August, which helped draw moisture north from an unusually active North American monsoon season. That generated several rounds of strong thunderstorms in August, particularly in the U.S. portions of the basin which are normally quite dry in August. The same general trend continued in the Snake River Basin during September, while a couple of unusually early and strong fronts brought heavy rains to much of southern British Columbia and both the Oregon and Washington coasts during the second half of the month.

In the end, the weather swings between very warm and very cold canceled each other out, with annual temperatures averaging slightly above the long term normal. Basin precipitation was below average (Chart 2), but because heavy precipitation fell at the right time of the winter and coincided with unusually cold temperatures, the resulting above average snowpack supported above average spring and annual runoff this year.

Columbia Basin Weather

	Temperature	Precipitation	Precipitation	Precipitation
Location	**Columbia Basin above The Dalles** **Departure from the 1981-2010 average (ºC / ºF)**	**Columbia River above Grand Coulee** **Percent of the 1981-2010 average (%)**	**Snake River above Ice Harbor** **Percent of the 1981-2010 average (%)**	**Columbia River above The Dalles** **Percent of the 1981-2010 average (%)**
August 2013	+1.7 / +3.1	83%	51%	75%
September 2013	+1.2 / +2.2	187%	248%	225%
October 2013	-0.8 / -1.5	24%	38%	30%
November 2013	+0.6 / +1.0	86%	48%	63%
December 2014	-0.9 / -1.7	62%	42%	48%
January 2014	+2.8 / +5.0	63%	50%	55%
February 2014	-1.3 / -2.4	133%	163%	149%
March 2014	+0.7 / +1.2	211%	168%	182%
April 2014	0.0	102%	97%	97%
May 2014	+0.7 / +1.3	95%	48%	70%
June 2014	-0.3 / -0.5	107%	66%	86%
July 2014	+2.4 / +4.3	57%	51%	56%
August 2014	+0.8 / +1.4	88%	192%	117%
September 2014	+1.2 / +2.2	91%	108%	90%
Water Year 2014	**+ 0.7 / +1.3**	**92%**	**83%**	**84%**

Data, temperature and precipitation maps from NOAA/National Weather Service Northwest River Forecast Center, Portland, OR

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2013 through 30 September 2014 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 16,827 m^3/s (594.3 kcfs) on 30 May 2014, 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 average unregulated August 2013-July 2014 streamflow at The Dalles was above average (104 percent of 1981-2010 average) and approximately 4 percent higher than last year's average flow. The total runoff volume at The Dalles during this same time period last year (WY 2013) was 161.6 km^3 (135.6 Maf) based on NWRFC data (100 percent of 1981-2010 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-13	89,774	2,542	96	119,227	3,376	95
Sep-13	68,567	1,942	122	98,733	2,796	114
Oct-13	43,196	1,223	95	84,651	2,397	102
Nov-13	37,426	1,060	77	77,877	2,205	83
Dec-13	29,551	837	74	72,405	2,050	79
Jan-14	31,161	882	78	75,072	2,126	77
Feb-14	29,782	843	68	90,768	2,570	79
Mar-14	70,957	2,009	118	189,811	5,375	128
Apr-14	110,564	3,131	92	220,439	6,242	95
May-14	311,429	8,819	123	493,401	13,972	120
Jun-14	324,583	9,191	111	463,447	13,123	105
Jul-14	195,666	5,541	110	255,694	7,240	108
Aug-14	90,213	2,555	97	126,757	3,589	102
Sep-14	60,399	1,710	107	86,078	2,437	99
Aug-Jul Average	**112,306**	**3,180**	**106**	**187,272**	**5,303**	**104**

Seasonal Runoff Forecasts and Volumes

Seasonal runoff volumes for the April-August 2014 period, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume in km^3	Volume in Maf	Percent of 1981-2010 Average
Libby Reservoir Inflow	8.23	6.67	113%
Duncan Reservoir Inflow	2.57	2.08	104%
Mica Reservoir Inflow	13.80	11.19	102%
Arrow Reservoir Inflow	27.39	22.21	101%
Columbia River at Birchbank	50.44	40.90	105%
Grand Coulee Reservoir Inflow	77.24	62.62	110%
Snake River at Lower Granite	25.63	20.78	99%
Columbia River at The Dalles	116.62	94.55	108%

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2014 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 River Forecast Center. The Libby inflow forecast is prepared by the U.S. Army Corps of Engineers. The 1 April 2014 forecast of January through July runoff for the Columbia River above The Dalles was 113.55 km^3 (92.06 Maf) and the actual observed runoff was 133.3 km^3 (108.1 Maf).

The following tabulations summarize the monthly forecasts since 1970 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 is 125.0 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
2014	118.5	98.7	126.0	129.4	135.1	132.8	133.3
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
2014	96.1	80.0	102.1	104.9	109.6	107.7	108.1
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

V - RESERVOIR OPERATION

General

The 2013-2014 Operating Year began with Canadian storage at 99.1 percent full. The Libby Reservoir (Lake Koocanusa) level was about 1.4 m (4.6 ft) below full, elevation 748.1 m (2,454.4 ft), at the start of the operating year (1 August 2013) 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 2013-2014 Operating Year was slightly above average in the Columbia Basin above Grand Coulee, and just below average in the Snake River above Lower Granite. The actual runoff in the Canadian portion of the Columbia Basin measured at Birchbank, B.C., was about 105 percent of normal for January through July 2014. The actual runoff for the overall Columbia Basin (U.S. and Canada combined) measured at The Dalles, OR, for January through July 2014 was 107 percent of normal.

The CRTOC signed one operating agreement, the Nonpower Uses Agreement, during the 2013-2014 Operating Year (see Section III Operating Arrangements) that impacted Mica and Arrow operations. Canadian storage ended the 2013-2014 operating year on 31 July 2014, at 18.7 km^3 (15.1 Maf) or 97.6 percent full.

Canadian Storage Operation

At the beginning of the 2013-2014 Operating Year (1 August 2013), actual Canadian storage provided under Article II of the CRT (Canadian storage) was at 18.9 km^3 (15.4 Maf) or 99.1 percent full. Canadian Treaty storage drafted to a minimum of 4.7 km^3 (3.8 Maf), or 24.4 percent full, on 16 April 2014. Canadian composite storage refilled to 18.7 km^3 (15.1 Maf), or 97.6 percent full, at the end of the operating year, 31 July 2014.

The Canadian Treaty composite storage operation was consistent with the DOP TSR for the 2013-14 operating year, as modified by Entity or Supplemental Operating Agreements such as the STLA, Nonpower Uses Agreement, NTSA and the Non-Treaty Summer Shaping

Agreement. During the second half of August 2013 and from October through December 2013, the TSR reflected the coordinated system being in proportional draft.

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 neither underruns nor overruns 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

At the start of the operating year on 1 August 2013, the Mica (Kinbasket) Reservoir level was 751.32 m (2,465.0 ft). This was 3.06 m (10.0 ft) below the normal full pool elevation. The Kinbasket Reservoir reached its maximum 2013 elevation of 754.63 m (2475.8 ft) on 16 September 2013. B.C. Hydro had earlier sought and received permission from the B.C. Comptroller of Water Rights to surcharge the reservoir by 0.3 m (1 ft), up to 754.68 m (2476.0 ft), on an interim basis for power purposes. In addition, B.C. Hydro requested, and the Corps approved, a deviation to the Kinbasket Reservoir CRT flood risk management level for 31 October 2013. Higher-than-normal Kinbasket Reservoir levels during this period were driven primarily by lengthy and significant generation restrictions related to a major upgrade of the Mica powerplant during the spring/summer of 2013.

As is normal, the Mica and Revelstoke generating stations ran relatively hard during the winter of 2013-2014 to meet high electrical demands and to position the Kinbasket Reservoir at an appropriate April level prior to the spring runoff. Kinbasket Reservoir reached its minimum level for the year, 724.78 m (2377.9 ft), on 25 April 2014; this was 1.98 m (6.5 feet) higher than the previous year’s minimum level on 24 April 2013.

During the spring and summer, Kinbasket Reservoir operated as required for power generation and reservoir refill management. From early May through early July, Mica generation was reduced to near zero as system loads declined. Following an outage of two Mica generators from late July through early August, Mica generation was increased as required to meet system load. At the end of the operating year (31 July 2014) the Kinbasket Reservoir level was 752.01 m (2467.2 ft), and the maximum reservoir level of 753.89 m (2473.4 ft) was reached on 2 September 2014.

Inflow into Mica Reservoir was 100 percent of normal over the period August to December 2013. Over this same period, the Mica outflow varied from a monthly average high of about 1,027 m^3/s (36.3 kcfs) in December 2013 to a monthly average low of about 281 m^3/s (9.9 kcfs) in October 2013. Inflows into Mica Reservoir were about 102 percent of normal over the period January to July 2014. The Mica discharge over this same period varied from a monthly average high of 1056 m^3/s (37.3 kcfs) in February to a monthly average low of 26 m^3/s (0.9 kcfs) in June.

The Mica project had a Treaty underrun of 1.87 km^3 (766.0 ksfd) on 31 July 2013. The maximum underrun for the operating period was 3.82 km^3 (1560.3 ksfd) on 20 September 2013, and the maximum overrun was 0.92 km^3 (376.3 ksfd) on 4 April 2014. At the end of the operating year (31 July 2014), the Mica project had a Treaty underrun of 1.60 km^3 (654.5 ksfd).

In mid-January and late March 2014, NTSA water was stored by both parties. B.C. Hydro and BPA verbally agreed to a 2014 Summer Shaping Agreement, utilizing Non-Treaty space at Mica to reduce high spring inflows in the lower Columbia River. Under this agreement, 0.85 km^3 (349.0 ksfd) of NT water was stored during May-July 2014, and subsequently released by 31 August 2014.

Revelstoke Reservoir

During the 2013-2014 Operating Year, the Revelstoke project was operated primarily 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 (1880.0 ft). During the winter, on occasion, the reservoir operated below its normal minimum level to provide additional short-term generation, reaching its lowest elevation of 570.50 m (1871.7 ft), or 2.5 m (8.3 ft) below full pool, on 1 November 2013.

Arrow Reservoir

At the start of the operating year on 1 August 2013, the Arrow Reservoir level was 436.70 m (1,432.7 ft), or 3.43 m (11.3 ft) below the normal full pool level of 440.13 m (1,444.0 ft). The reservoir drafted steadily from August 2013 through to January 2014, reaching its lowest level for the 2013-2014 operating year, 427.06 m (1,401.1 ft), on 31 January 2014 – this was 0.88 m (2.9 feet) lower than the previous year's minimum level on 13 February 2013. Local inflow into Arrow Reservoir was well below normal (76% of normal) over the period August-December 2013. The Keenleyside Dam discharge varied from a monthly average high of 1,750 m^3/s (61.8 kcfs) in August to a monthly average low of 717 m^3/s (25.3 kcfs) in October.

Local inflow into Arrow Reservoir was 97% of normal over the period January-July 2014, but inflow was only 55% of normal during the coldest months of January and February. Outflow over this same period varied from a monthly average low of 528 m^3/s (18.7 kcfs) in April to a monthly average high of 1,879 m^3/s (66.4 kcfs) in July. Throughout April, the Arrow Reservoir was operated at approximately the average elevation for the previous ten years, which was at least 1.5 m (5 ft) below the April flood risk management level of 430.99 m (1,414.0 ft). As basin inflows increased rapidly during the second half of May due to snowmelt runoff, the Arrow Reservoir refilled rapidly through June and into July. The reservoir reached its maximum level for the year, 439.11 m (1,440.6 ft), or 1.02 m (3.4 ft) below normal full pool, on 3 July 2014.

Under terms of the LCA, B.C. Hydro exercised 68.5 hm^3 (28 ksfd) of provisional storage in October 2013; this zeroed out the LCA account balance that had been carried over from the previous operating year. In November-December 2013, B.C. Hydro exercised 0.45 km^3 (182 ksfd) of STLA provisional draft. In March 2014, 0.24 km^3 (98 ksfd) of the draft was returned to storage, leaving an outstanding provisional draft account balance of 0.21 km3 (84 ksfd) below full to be stored back at some future time.

The CRTOC negotiated a Nonpower Uses Agreement (NPU) for 2013-14 in order to manage Canadian and U.S. fisheries needs. In January 2014, Arrow Treaty flows were reduced to enable 1.23 km^3 (504 ksfd) of Flow Augmentation storage as specified under the NPU. Arrow actual discharges for January averaged about 1,339 m^3/s (47.3 kcfs) for the month. Even with the NPU provisions to protect Canadian whitefish spawning, the Arrow

discharge reduced substantially in February, to 801 m^3/s (28.3 kcfs), due to a significant reduction in Arrow Treaty discharges in February. Even with this flow reduction, the whitefish protection level for January-March 2014 was determined to be "Tier 1" (acceptable), as defined by an arrangement between Canada's Department of Fisheries and Oceans and B.C. Hydro. Additional provisions under the NPU maintained Arrow discharges during April-June 2014 at or above 510 m^3/s (18 kcfs) to protect rainbow trout spawning downstream of Keenleyside Dam. All of the water stored for Flow Augmentation under the NPU was released, as needed for U.S. salmon migration, in July 2014.

Under the 2012 NTSA, B.C. Hydro and BPA stored a total of 0.85 km^3 (349 ksfd) into Non-Treaty Active storage from late May through mid-July 2014 for the mutual benefit of both parties. The resulting peak flow in the Columbia River at Birchbank was reduced by 396 m^3/s (14 kcfs) to a maximum of 3,681 m^3/s (130 kcfs) on 8 July 2014. Water stored under the 2014 NTSA Summer Shaping Agreement was released in August 2014.

From early July through August 2014, the Arrow Reservoir drafted fairly quickly, with the level reaching 433.67 m (1422.8 ft) on 31 August 2014. Factors contributing to this draft included lower than expected generation from the Mica powerplant in early July and a two-week outage for two of the generating units from late July to early August, resulting in below-normal inflow into Arrow Reservoir.

Duncan Reservoir

Operation of the Duncan Reservoir during the 2013-2014 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 576.65 m (1891.9 ft), or 0.04 m (0.1 ft) below full pool, on 8 August 2013. Duncan discharges were adjusted as needed from August through 1 September 2013 to target a reservoir elevation of 575.5 +/- 0.3 m (~1,888 +/- 1 ft) as per the WUP requirements.

After 1 September 2013, 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 period 27 September to 21

October 2013, the DRL target release (WUP requirement) was changed from 73 to 100 m^3/s (2.6 to 3.5 kcfs) to test a new fish (kokanee) operating policy. Discharges were increased during the last week of October 2013 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 250 m^3/s (8.8 kcfs) to meet Treaty flood risk management requirements. For the first three weeks of January 2014, the Duncan discharge remained high to maintain 250 m^3/s (8.8 kcfs) at DRL in order to continue drafting Duncan Reservoir and reduce Arrow flows in aid of whitefish spawning. Duncan flows were adjusted across the balance of January and February to draft the reservoir to meet the Treaty flood risk management target of 557.60 m (1829.4 ft) by 28 February 2014.

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, 546.87 m (1794.2 ft), on 25 April 2014. By comparison, the reservoir reached a similar minimum level of 546.92 m (1794.4 ft) on 28 April 2013. The project was operated to provide the agreed minimum flow of 73 m^3/s (2.6 kcfs) at DRL as required for fish until early May when the freshet began abruptly and the Duncan Dam discharge was adjusted to manage DRL flows below 120 m^3/s (4.2 kcfs) as per WUP requirements. For the first three weeks of May, Duncan Dam discharge was maintained in the range 85 to 113 m^3/s (3 to 4 kcfs), and DRL flows were allowed to increase naturally until the flow peaked at approximately 300 m^3/s (10.6 kcfs) in mid-May.

The reservoir discharge was reduced to a minimum of 3 m^3/s (0.1 kcfs) on 22 May 2014 to begin reservoir refill and manage the level of Kootenay Lake. Releases from Duncan Reservoir were held at minimum until early July to refill the reservoir and avoid increasing the peak level of Kootenay Lake. Duncan discharges were increased on 4 July 2014 to manage the rate of refill of Duncan Reservoir, targeting the reservoir level to be within 0.3 m (1 ft) of its normal full pool level, 576.68 m (1892 ft), by early August 2014, as per WUP requirements.

By 13 August 2014, the Duncan Reservoir level peaked close to full pool at 576.53 m (1891.5 ft). Duncan discharges were then adjusted as needed from August through 1 September 2014 to target a reservoir level of 575.5 +/- 0.3 m (1888 +/- 1 ft). During early September, Duncan outflows were increased to a maximum DRL flow of 250 m^3/s (8.8 kcfs)

to draft the reservoir. Beginning on 25 September, discharges were ramped down to prepare for the fish spawning flow of 73 m^3/s (2.6 kcfs) during the period 1 - 21 October 2014.

Libby Reservoir

Operation of Libby Dam and Lake Koocanusa is shown in Chart 8 of this document. Lake Koocanusa ended July 2013 at elevation 748.1 m (2454.4 ft). The project was drafted to elevation 746.5 m (2449.0 ft) at the end of August, with outflows reduced gradually from 396.4 m^3/s (14 kcfs) to the bull trout minimum of 226.5 m^3/s (8 kcfs) over the final week of August 2013. To assist with the continuing habitat restoration work in the Kootenai River, outflow was reduced to 169.9 m^3/s (6 kcfs) during the first week of September 2013, and reduced again to 113.3 m^3/s (4 kcfs) for the month of October 2013. The final April – August 2013 inflow volume to the project was 8.9 km^3 (7.2 MAF), or 122 percent of normal (1981 – 2010, 30 year normal).

The December 2013 water supply forecast for April-August 2014 runoff came in at 6.8 km^3 (5.5 MAF), or 94 percent of average, which set the end of December FRM elevation to 739.6 m (2426.6 ft). Subsequent forecasts ranged from 6.4 to 8.5 km^3 (5.2 to 6.9 MAF), with a May 2014 forecast of 8.6 km^3 (7.0 MAF), or 119 percent of average. Libby was drafted to a minimum elevation of 727.3 m (2386.0 ft) on 3 May 2014. Libby refill operations can begin as early as ten days prior to the ICF date but refill began on the ICF date of 9 May in 2014. Libby outflow was held at 453.1 m^3/s (16 kcfs) until 16 May, when the first of two discharge peaks was released for sturgeon flow augmentation. Powerhouse capacity was released through 23 May 2014; flows were then decreased to 509.7 m^3/s (18 kcfs) for one week, followed by an additional week at powerhouse capacity through 9 June. Outflow was then decreased gradually to control refill, with the reservoir elevation peaking at 747.7 m (2453.1 ft) on 23 July 2014. By 3 August 2014, the outflow was decreased to the summer bull trout minimum of 254.8 m^3/s (9 kcfs), which was held through the end of the month. The final April – August 2014 inflow volume to the project was 8.2 km^3 (6.7 MAF), or 113 percent of normal (1981 – 2010, 30 year normal). In September, the outflow of 254.8 m^3/s (9 kcfs) was continued until the final days of the month when the outflow was transitioned to

the September bull trout minimum of 169.9 m^3/s (6 kcfs). The reservoir elevation at the end of September was 746.0 m (2,447.4 ft).

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay reached a 2013 peak level of 533.20 m (1,749.3 ft) on 26 June. As runoff receded during July, Kootenay Lake drafted, but discharges from the lake continued at maximum until 13 July 2013 when the lake drafted to 532.79 m (1748.0 ft). At that time, the Corra Linn spill was gradually reduced and the Corra Linn forebay level returned to its normal operating range. In August 2013, lake discharges were adjusted as needed to manage the Kootenay Lake level according to the IJC Order.

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 Brilliant flow of 510 m^3/s (18 kcfs) during the period December to September and 453 m^3/s (16 kcfs) during October-November, although the target flows are subject to water availability. Due to low basin inflows in autumn 2013, the discharge at Brilliant Dam was reduced to its minimum flow target from September through mid-November. In late November, discharges from the upstream Libby Dam were increased, and Kootenay Lake discharges were then increased, as needed, to control the Kootenay Lake level below the IJC Order maximum level of 531.97 m (1745.32 ft) and prepare for the Brilliant Expansion outage in January 2014. Low inflows during the latter half of December resulted in the lake drafting and discharges at Brilliant being reduced to 425-453 m^3/s (15-16 kcfs) to manage the lake level. On 31 December 2013, the Kootenay Lake level was 531.48 m (1743.7 ft), or 0.50 m (1.6 ft) below the maximum IJC Order reference level.

In January 2014, the Brilliant Expansion powerplant was out of service and the Kootenay River discharge at Brilliant was maintained at its minimum target of 510 m^3/s (18 kcfs). Due to lower inflows in February, the Brilliant discharge was reduced below its target minimum to 453 m^3/s (16 kcfs). From 14 March onwards, the Corra Linn and Kootenay Canal projects were operated to maximize discharges from Kootenay Lake, limited only by the natural channel constriction at Grohman Narrows. Kootenay Lake reached its minimum level of 530.22 m (1739.6 ft) on 24 March 2014.

On 1 April 2014, the Kootenay Lake level was 530.51 m (1740.5 ft), 0.36 m (1.2 ft) above the IJC Order reference level of 530.14 m (1739.32 ft). Despite maximum outflows from the lake, the Kootenay Lake level remained above the IJC Order reference level until the declaration of Spring Rise. During this time, the Corra Linn and Kootenay Canal projects were operated to discharge maximum possible ("free fall" or "free flow" conditions), which maintained compliance with the IJC Order requirements.

The International Kootenay Lake Board of Control, after consultation with FortisBC, declared the Commencement of Spring Rise for Kootenay Lake on 15 April 2014. Following this declaration, the Corra Linn and Kootenay Canal projects continued to pass maximum discharge (free flow), limited only by the restriction of Grohman Narrows, throughout the spring runoff period. The level of Kootenay Lake level continued to increase during the April-May period, peaking at 533.50 m (1750.3 ft) on 27 May 2014. By comparison, in 2012, the peak level was 534.54 m (1753.7 ft), the highest level since 1974. In 2013, the peak lake level was 533.20 m (1749.3 ft). Discharge from Kootenay Lake peaked at 2124 m3/s (75 kcfs) on 27 May 2014, while the Kootenay River discharge at Brilliant peaked at 2549 m^3/s (90 kcfs) on 26 May 2014.

By mid-June, the lake level had dropped below 533.10 m (1749.0 ft), and maximum discharge conditions (free fall) were terminated. The Corra Linn spill was gradually reduced and the Corra Linn forebay level was returned to its normal operating range. In August, lake discharges were adjusted to draft Kootenay Lake between 530.96 m (1742.0 ft) to 531.05 m (1742.3 ft) in preparation for a lengthy Kootenay Canal full powerplant outage (canal dewatering) starting on 5 September 2014.

VI - FLOOD RISK MANAGEMENT AND POWER ACCOMPLISHMENTS

General

During the period covered by this report, the Duncan, Arrow, and Mica reservoirs were operated for power, flood risk management, 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 2013-2014 and the 2014 -2015 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 of Canadian storage are determined by the ORCs, Mica/Arrow project operating criteria, and nonpower constraints as implemented 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 2013 water supply forecast for April-August 2014 runoff was 6.8 km^3 (5.5 Maf), or 94 percent of average (based on the 1981-2010 inflow). Based on this forecast, the recommended draft for Libby Reservoir was 1.73 km^3 (1.4 Maf), to elevation 739.6 m (2426.6 ft) on 31 December. Libby was operated to its VarQ flood risk management storage reservation diagram. Both Libby and Duncan dams began refill at the beginning of May according to the Initial Controlled Flow (ICF) date.

Flood Risk Management

Overall, the 2014 water supply for the Columbia Basin was slightly above average. The upper Columbia Basin had slightly higher than average flows. While the Kootenai Basin did not encounter the higher than average June precipitation as seen in 2012 and 2013, the seasonal runoff volume remained well above average. Most of the other sub-basins had roughly average flows, leading to an observed April-August volume at The Dalles of 116.6 km^3 (94.55 Maf), which is 108 percent of the 1981-2010 NWRFC normal. During the drawdown period, the reservoir system, including the Columbia River Treaty projects, is required to draft for flood risk management 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 16,827 m^3/s (594.3 kcfs) on 30 May 2014, and a regulated daily peak flow of 10,129 m^3/s (357.7 kcfs) occurred on 27 May 2014 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 6.5 m (21.25 ft) on 30 May 2014, and the peak observed stage was 3.5 m (11.5 ft) on 28 May 201 while the flood stage is 4.88 m (16 ft).

For the 2013-2014 Operating Year, the Canadian Entity elected to operate Mica and Arrow to the flood risk management 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 risk management operation were made in accordance with the Treaty FCOP. For 2014, 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	322.0	9118
February Forecast	266.7	7553
March Forecast	334.2	9463
April Forecast	332.5	9416
May Forecast	371.8	10528

Refill at the projects can commence relative to the date when the unregulated flow at The Dalles is expected to equal or exceed the ICF (ICF date). For WY 2014, the ICF date was declared as 9 May based on the May forecast ICF of 10,528 m^3/s (372 kcfs). The flood risk management 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. As mentioned earlier, the observed daily

peak flow at The Dalles this year was 10,129 m^3/s (357.7 kcfs), occurring on 27 May 2014. 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 2014, Arrow Reservoir filled faster relative to Grand Coulee compared to the guideline. Arrow Dam was operated to meet local as well as system flood risk management objectives and Grand Coulee was operated for system flood risk management objectives.

Canadian Entitlement and Downstream Power Benefits

From 1 August 2013 through 30 September 2014, 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 2013 through 31 July 2014, the Canadian Entitlement amount, before deducting transmission losses, was 505.5 aMW of energy, scheduled at rates up to 1336 MW capacity. From 1 August 2014 through 30 September 2014, the amount, before deducting transmission losses, was 479.9 aMW of energy, scheduled at rates up to 1369 MW capacity. The Canadian Entitlement obligation was determined by the 2013-2014 and 2014-2015 AOP/DDPBs.

During the course of the 2013-2014 Operating Year, there were two curtailment events for Canadian Entitlement deliveries. These included a 28 MWh cut on 28 September 2013 due to transmission congestion and a 149 MWh cut on 1 April 2014 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). No

Entitlement power was disposed directly in the U.S. during 1 August 2013 through 30 September 2014, 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.

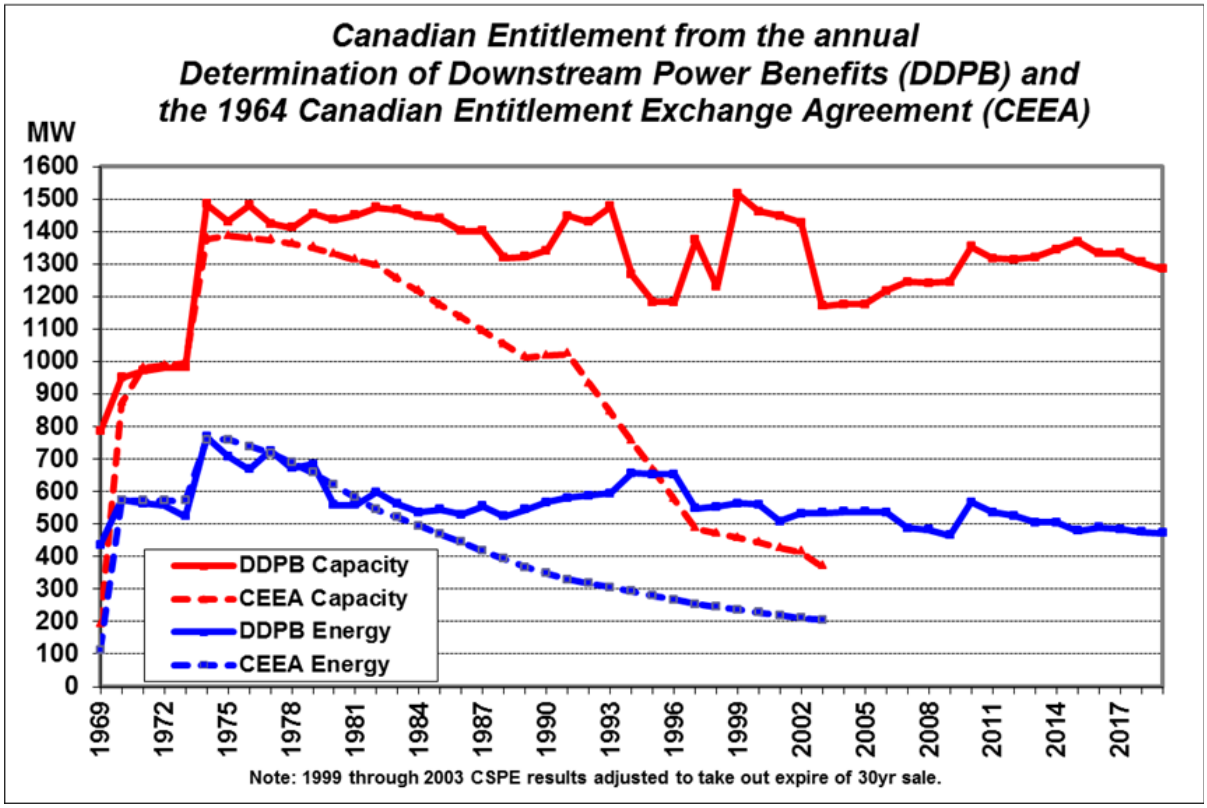


Figure 5: Canadian Entitlements: Agreed CEEA Amounts vs DDPB Amounts

The Canadian Entitlement Exchange Agreement amounts for the Canadian Entitlement were based on 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 (agreed to annually for the 6th succeeding year) and the Canadian Entitlement Exchange Agreement amounts (agreed to in 1964).

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 (27.5%), 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

Lead by the B.C. Treaty Review team, the Canadian Entity completed a series of community meetings in November 2013 to discuss with Basin residents how their interests and feedback had been considered in the draft B.C. recommendations. Results of the additional analysis undertaken in response to previous feedback were also presented specifically related to a mid-elevation constant pool alternative for Arrow Lakes Reservoir and a basin wide ecosystem alternative. The draft B.C. recommendation was released in fall 2013, and, on 13 March 2014, the Honorable Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review, announced the release of the Government of British Columbia's decision to continue the Columbia River Treaty and seek improvements within its existing framework.

B.C.'s decision includes 14 principles that will guide B.C. in any future discussions with Canada and the U.S. on the future of the Treaty. The decision and principles follow more than two years of technical, social, economic and legal studies and an extensive consultation process with various levels of government, stakeholder groups, First Nations and the public. The principles include considerations around flood risk management, hydropower generation, ecosystems and climate change, while allowing for flexibility moving forward to adapt to evolving economic, social and environmental circumstances in each country.

In the last (2013) Annual Report, it was noted that the U.S. Entity had completed an initial "working draft" recommendation proposal to the U.S. Department of State, which was released to regional sovereigns, stakeholders and the general public for comments on 27 June 2013. After feedback had been compiled and evaluated, the U.S. Department of State and U.S. Entity conducted additional outreach to sovereigns, stakeholders and the general public to be incorporated into a revised "draft recommendation," which was released for public review and comment between 20 September and 25 October 2013.

During the period between 27 June and 25 October 2013, the U.S. Entity received nearly 4,000 written comments on the draft recommendation from regional sovereigns and

stakeholders. The primary goal of the U.S. Entity's extensive outreach throughout the Pacific Northwest during its Treaty Review effort was to produce a regional recommendation that reflected the broadest possible consensus.

Additional regional outreach and briefings were conducted by U.S. Entity staff in the November and early December 2013 timeframe, resulting in a final recommendation that the U.S. Entity transmitted to the U.S. Department of State on 13 December 2013. Called "The Regional Recommendation concerning the Future of the Columbia River Treaty after 2024," this final recommendation was accompanied by a cover letter signed by the U.S. Entity Chair and the U.S. Entity Member recommending "…both countries to develop a modernized Treaty framework that reflects the actual value of coordinated power operations with Canada, maintains an acceptable level of flood risk and supports a resilient and healthy ecosystem-based function throughout the Columbia River Basin."

The Final Recommendation included nine key principles that the U.S. Entity noted are "…to be taken together with the intent that all of the interests herein be improved." The document also included a section describing seven domestic areas of interest that emerged during the U.S. Treaty Review process that could be addressed post-2013. The U.S. Entity's Final Recommendation and the three-year process leading up to it also marked the successful conclusion of the regional recommendation chapter of the U.S. Treaty Review, and the beginning of a formal review by the U.S. Government. At the time this Annual Report was being prepared, that U.S. Government review was ongoing.

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 6 shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2013-2014 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 688 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 7 compares the actual operation of the composite Canadian storage to the results of the DOP TSR study.

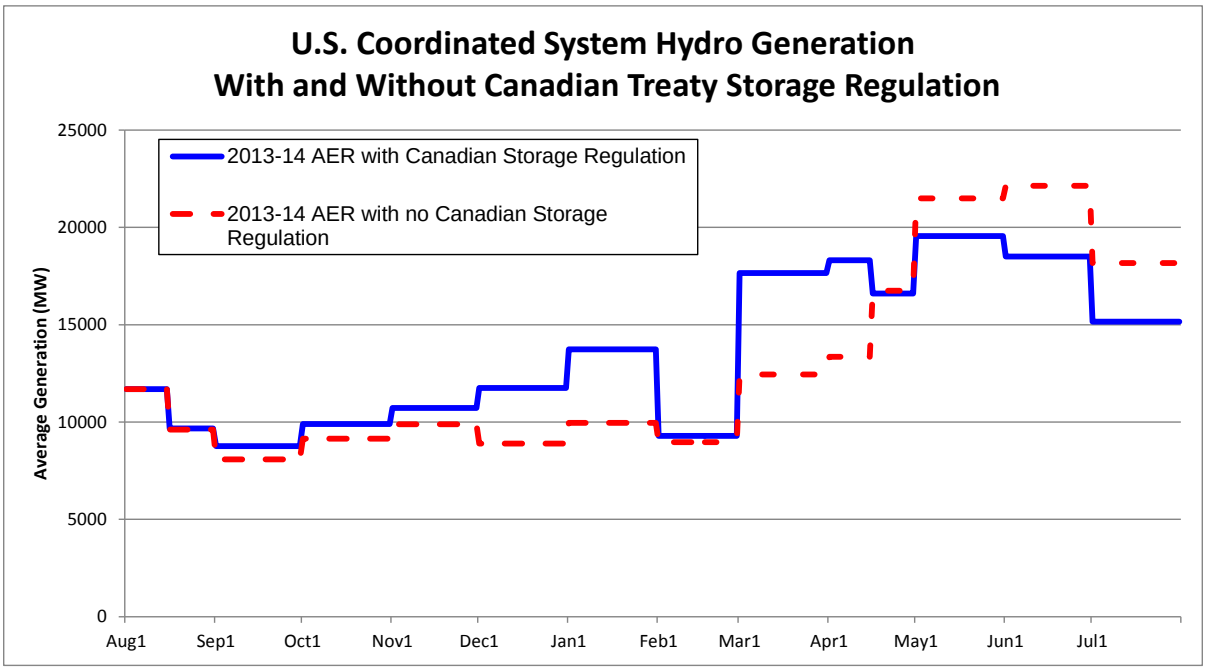


Figure 6: U.S. Coordinated System Hydro Generation

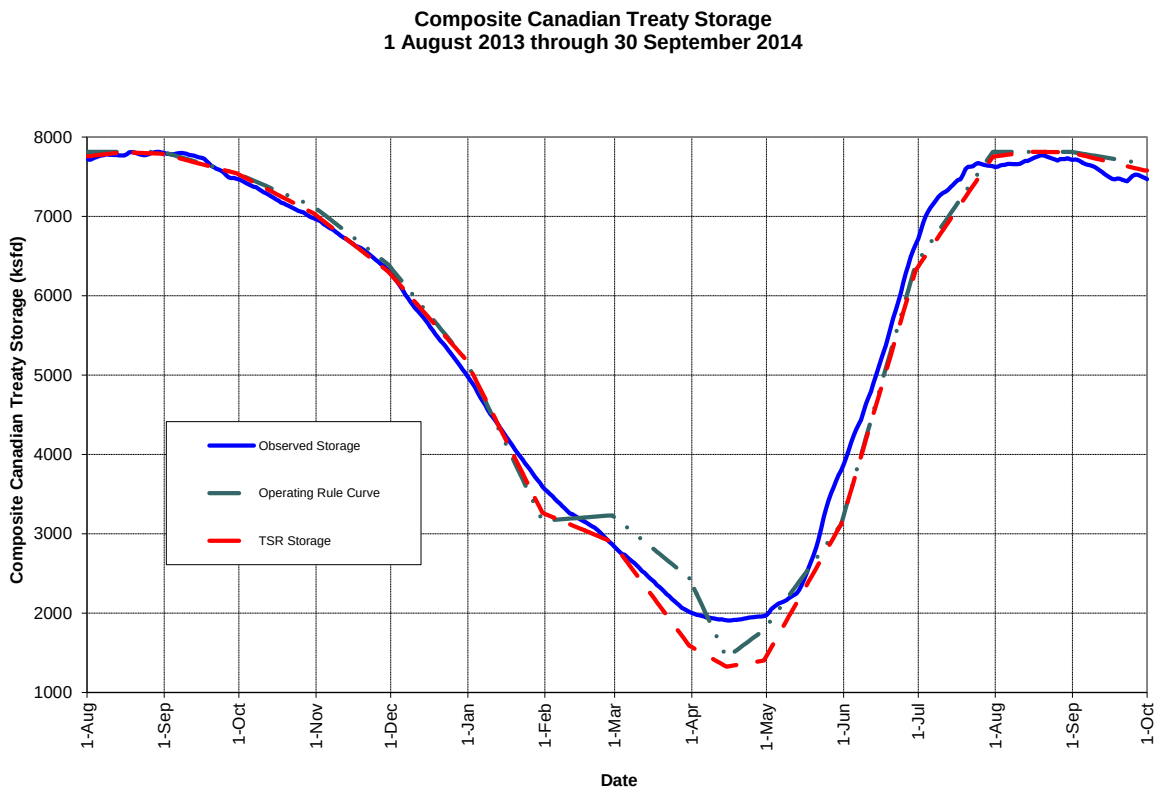


Figure 7: Composite Canadian Treaty Storage

The TSR had the system operating in proportional draft for the second half of August and October through December 2013. Starting in late November, the STLA Provisional Account was drafted and decreased the Treaty Storage content when compared to the TSR content. This was most notable in December when the account balance was 0.45 km^3 (182 ksfd) drafted. Under the 2014 NPU agreement, the U.S. stored 1.23 km^3 (504 ksfd) above the TSR for Flow Augmentation in January and maintained that balance until it was released by the end of July. The parties mutually agreed to shape February and March flows for better operating conditions. Also under the NPU agreement, Treaty flows were set low during April through June to support trout spawning which contributed to Treaty Storage being above the TSR during that timeframe. At the end of July, Treaty Storage was below the TSR due to the drafted STLA Provisional Account.

Figure 8 shows the difference in Arrow plus Duncan regulated outflows in the DOP TSR and the actual daily CRT outflows. The daily unregulated inflows are also shown for comparison purposes.

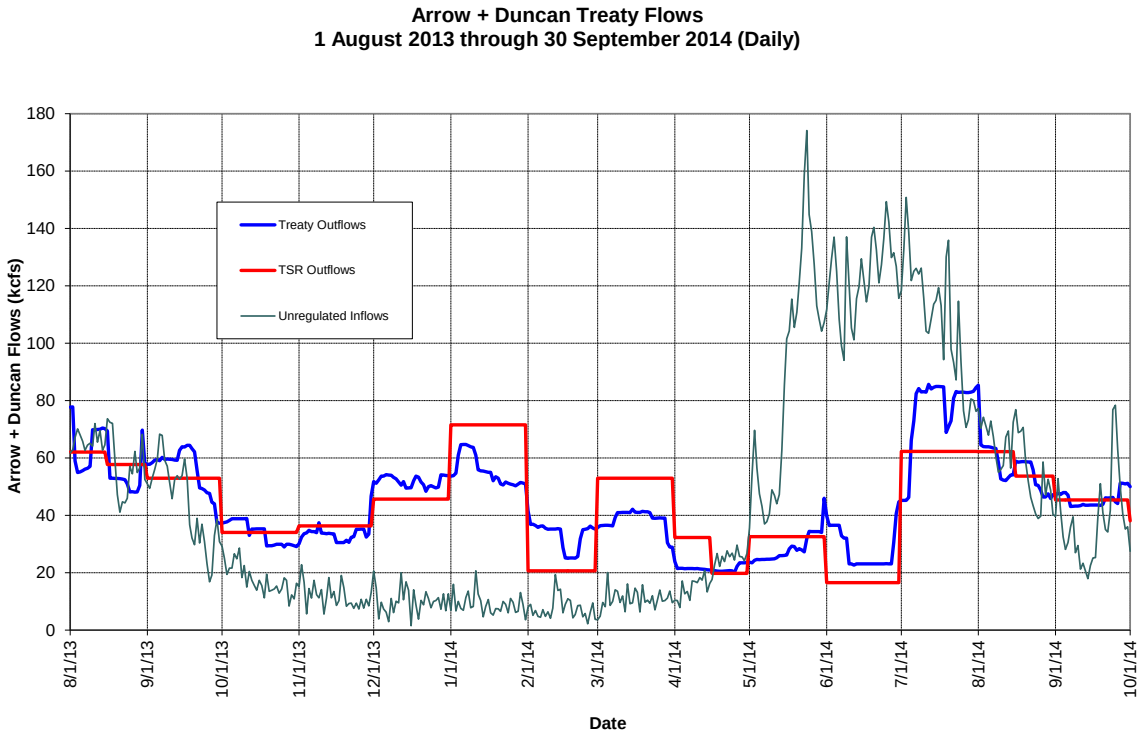


Figure 8: Arrow and Duncan Treaty Flows

Figure 9 summarizes the Treaty accounting including supplemental 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 supplemental operating agreement as they were 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 2013 through September 2014

All units in KSFD	2013							2014										
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)	7752.6	7807.9	7790.5	7544.2	7040.0	6305.6	5204.0	3265.1	2898.4	1591.2	1326.1	1404.5	3119.3	6322.7	7752.6	7814.6	7807.8	7578.6
2) Actual Treaty Content (w/SOA's)	7742.4	7769.3	7804.5	7475.5	6980.0	6318.6	5026.7	3592.6	2869.7	2018.1	1910.3	1963.1	3798.3	6648.7	7631.2	7713.8	7721.1	7484.7
3) % full (actual Treaty/7814.6 ksfd)	99.1%	99.4%	99.9%	95.7%	89.3%	80.9%	64.3%	46.0%	36.7%	25.8%	24.4%	25.1%	48.6%	85.1%	97.7%	98.7%	98.8%	95.8%
4) Final deviation from TSR	**-10.2**	**-38.6**	**14.0**	**-68.7**	**-60.0**	**13.0**	**-177.3**	**327.5**	**-28.7**	**426.9**	**584.2**	**558.6**	**679.0**	**326.0**	**-121.4**	**-100.8**	**-86.7**	**-93.9**

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

	2013							2014										
Balance in each period	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
5) Libby Coord Agreement (LCA)	0.0	0.0	0.0	-16.0	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
6) Short Term Libby Agreement (STLA)	0.0	0.0	0.0	0.0	0.0	-48.0	-182.0	-182.0	-182.0	-84.0	-84.0	-84.0	-84.0	-84.0	-84.0	-84.0	-96.0	-203.0
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	-16.0	0.0	-48.0	-182.0	322.0	322.0	420.0	420.0	420.0	420.0	420.0	-84.0	-84.0	-96.0	-203.0
9. Inadvertent (Line 4 - Line 8)	**-10.2**	**-38.6**	**14.0**	**-52.7**	**-60.0**	**61.0**	**4.7**	**5.5**	**-350.7**	**6.9**	**164.2**	**138.6**	**259.0**	**-94.0**	**-37.4**	**-16.8**	**9.3**	**109.1**
									(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)

	2013							2014										2014
TSR Date	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
6-Oct-14	**7752.6**	7814.6	7807.8	7578.6	7135.4	6491.4	5282.1	3158.4	1734.5	1364.7	1370.2	1561.4	3537.7	6366.1	7752.6			
22-Aug-13		**7807.9**	7771.4	7221.2	6586.7	5953.4	5183.5	3051.6	1930.8	1505.9	1283.8	1376.3	3252.6	6305.7	7752.6			
6-Sep-13			**7790.5**	7343.0	6716.4	6087.3	5204.0	3072.0	1930.8	1518.8	1296.8	1389.2	3265.5	6318.6	7752.6			
19-Sep-13				7544.2	6974.2	6309.2	5204.0	3072.0	1930.8	1466.5	1244.4	1336.8	3213.1	6266.2	7752.6			
4-Oct-13				**7544.2**	7127.1	6394.7	5204.0	3072.0	1930.8	1506.8	1284.7	1377.1	3253.5	6306.5	7752.6			
21-Oct-13					7127.1	6394.7	5204.0	3072.0	1930.8	1525.2	1303.2	1395.6	3271.9	6325.0	7752.6			
7-Nov-13					**7040.0**	6368.1	5204.0	3072.0	1930.8	1479.7	1257.6	1350.0	3226.4	6279.4	7752.6			
21-Nov-13						6373.1	5204.0	3051.8	1930.8	1466.9	1244.8	1337.3	3213.6	6266.7	7752.6			
11-Dec-13						**6305.6**	5204.0	3052.4	2401.5	1470.2	1248.1	1340.6	3216.9	6279.3	7752.6			
19-Dec-13							5204.0	3048.0	2401.5	1473.6	1251.5	1344.0	3220.3	6282.8	7752.6			
13-Jan-14							**5204.0**	3265.1	2827.5	1552.9	1343.3	1457.9	3301.7	6099.6	7735.2			
23-Jan-14								3265.1	2826.6	1565.7	1354.1	1469.7	3311.5	6102.1	7730.7			
13-Feb-14								**3265.1**	2903.0	2286.9	2279.2	2379.5	4011.5	6209.5	7752.6			
21-Feb-14									2894.2	2305.6	2299.6	2396.0	4020.3	6214.9	7752.6			
12-Mar-14									**2898.4**	1580.4	1365.9	1480.7	3287.3	6085.8	7698.2			
20-Mar-14										1585.1	1376.2	1497.7	3301.8	6091.6	7698.9			
14-Apr-14										**1591.2**	1329.6	1455.0	3338.8	6273.7	7752.6			
24-Apr-14											**1326.1**	1438.4	3240.5	6223.7	7752.6			
12-May-14												**1404.5**	3119.3	6197.4	7752.6			
22-May-14													3119.3	6267.5	7730.3			
11-Jun-14													**3119.3**	6324.4	7752.6			
25-Jun-14														6290.0	7752.6	7814.6	7814.6	
10-Jul-14														**6322.7**	7752.6	7814.6	7814.6	
24-Jul-14															7752.6	7814.6	7814.6	7663.6
7-Aug-14															**7752.6**	7814.6	7808.5	7575.7
21-Aug-14																**7814.6**	7810.1	7594.1
5-Sep-14																	**7807.8**	7551.2
19-Sep-14																		7398.2
6-Oct-14																		**7578.6**
Proportional Draft Point (PDP)	1.000	1.000	2.196	1.000	2.078	2.047	1.844	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	2.209	2.175

Figure 9: 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	2.20	24.27	12.71	6.70	104.71
February	2.13	24.67	12.77	6.40	89.38
March	2.17	24.58	12.59	6.79	109.57
April	2.33	26.84	13.67	8.47	113.55
May	2.35	27.35	13.84	8.63	119.33
June	2.49	28.14	14.47	8.73	116.51
Actual	2.57	27.39	13.80	8.23	116.62

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	1.78	19.68	10.30	5.43	84.89
February	1.73	20.00	10.36	5.19	72.46
March	1.76	19.93	10.21	5.51	88.83
April	1.89	21.76	11.08	6.87	92.06
May	1.90	22.17	11.22	7.00	96.74
June	2.02	22.81	11.73	7.07	94.45
Actual	2.08	22.21	11.19	6.67	94.55

Table 2M (metric): 2014 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			10.7	10.7	10.3	10.8	10.5	8.6
PROBABLE DATE-31JULY INFLOW, hm3	**		10683.3	10726.9	10319.3	10803.9	10467.5	8639.4
95% FORECAST ERROR FOR DATE, hm3			1802.7	1276.5	1113.4	1027.9	982.1	971.3
95% CONF.DATE-31JULY INFLOW, hm3	1/		8880.6	9450.3	9205.9	9776.0	9485.5	7668.1
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		8880.6					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		4651.7					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		4405.6					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		742.4					
JAN31 ORC, m	7/		740.5					
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/		8694.1	9251.9				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		4446.2	5906.1				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		4386.6	5288.8				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		742.3	744.6				
FEB28 ORC, m	7/		740.2	740.2				
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/		8481.0	9025.1	8975.7			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0			
MIN APR1-JUL31 OUTFLOW, hm3	4/		4218.7	5678.6	4218.7			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		4372.2	5288.0	3877.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		742.2	744.6	740.9			
MAR31 ORC, m	7/		740.2	740.2	740.2			
BASE ECC, m	8/	740.2						
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/		8037.0	8552.6	8506.2	9267.7		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		3998.5	5458.4	3998.5	3998.5		
VRC APR30 RESERVOIR CONTENT, hm3	5/		4596.0	5540.4	4126.8	3365.4		
VRC APR30 RESERVOIR CONTENT, METERS	6/		742.8	745.3	741.6	739.5		
APR30 ORC, m	7/		740.2	740.8	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/		6358.5	6766.4	6729.5	7341.8	7512.5	
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	5230.8	3770.9	3770.9	3770.9	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		6046.9	7098.9	5676.0	5063.7	4893.0	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		746.6	749.2	745.6	744.0	743.6	
MAY31 ORC, m	7/		745.5	745.8	745.5	744.1	743.6	
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/		3214.8	3421.0	3406.2	3714.9	3803.7	3880.1
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		509.7	509.7	906.1	509.7	509.7	509.7
MIN JUL1-JUL31 OUTFLOW, hm3	4/		2449.8	2882.1	2449.8	2449.8	2449.8	2449.8
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7869.5	8095.6	7678.2	7369.4	7280.7	7204.3
VRC JUN30 RESERVOIR CONTENT, METERS	6/		751.1	751.6	750.6	749.8	749.6	749.4
JUN30 ORC, m	7/		751.1	751.6	750.6	749.8	749.6	749.4
BASE ECC, m	8/	752.9						
JUL 31 ORC, m			752.9	752.9	752.9	752.9	752.9	752.9

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (8634.54 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 FRM REQUIREMENTS
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 2: 2014 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			8661.0	8696.3	8365.9	8758.8	8486.1	7004.0
PROBABLE DATE-31JULY INFLOW, KSFD	**		4366.6	4384.4	4217.8	4415.9	4278.4	3531.2
95% FORECAST ERROR FOR DATE, KSFD			736.8	521.8	455.1	420.1	401.4	397.0
95% CONF.DATE-31JULY INFLOW, KSFD	1/		3629.8	3862.6	3762.7	3995.8	3877.0	3134.2
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3629.8					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1901.3					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1800.7					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2435.7					
JAN31 ORC, FT	7/		2429.6					
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/		3553.6	3781.5				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1817.3	2414.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1792.9	2161.7				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2435.3	2443.0				
FEB28 ORC, FT	7/		2428.5	2428.5				
BASE ECC, FT	8/	2428.5						
LOWER LIMIT, FT		2394.8						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3466.4	3688.8	3668.6			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1724.3	2321.0	1724.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1787.1	2161.4	1584.9			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2435.2	2443.0	2430.8			
MAR31 ORC, FT	7/		2428.4	2428.6	2428.4			
BASE ECC, FT	8/	2428.6						
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/		3285.0	3495.7	3476.7	3788.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1634.3	2231.0	1634.3	1634.3		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1878.5	2264.5	1686.8	1375.5		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2437.1	2445.1	2433.0	2426.3		
APR30 ORC, FT	7/		2428.4	2430.5	2428.4	2426.3		
BASE ECC, FT	8/	2430.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2598.9	2765.6	2750.5	3000.8	3070.6	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0	3000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1541.3	2138.0	1541.3	1541.3	1541.3	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2471.6	2901.6	2320.0	2069.7	1999.9	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2449.4	2458.0	2446.3	2441.1	2439.7	
MAY31 ORC, FT	7/		2445.8	2446.9	2445.8	2441.1	2439.7	
BASE ECC, FT	8/	2446.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1314.0	1398.3	1392.2	1518.4	1554.7	1585.9
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		18000.0	18000.0	32000.0	18000.0	18000.0	18000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		1001.3	1178.0	1001.3	1001.3	1001.3	1001.3
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3216.5	3308.9	3138.3	3012.1	2975.8	2944.6
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2464.1	2465.9	2462.6	2460.1	2459.4	2458.8
JUN30 ORC, FT	7/		2464.1	2465.9	2462.6	2460.1	2459.4	2458.8
BASE ECC, FT	8/	2470.1						
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 FRM REQUIRMENTS.
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			21.6	21.8	21.1	22.2	21.1	15.8
& IN hm3	**		21630.9	21767.4	21113.2	22237.1	21130.1	15812.9
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/		18003.6					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		8682.0					
UPSTREAM DISCHARGE, hm3	4/		4899.1					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		4335.3					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		431.1					
JAN31 ORC, m	7/		429.7					
BASE ECC, m	8/	429.7						
LOWER LIMIT, m		421.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		17571.5	18629.8				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		8339.4	11232.8				
UPSTREAM DISCHARGE, hm3	4/		5023.4	5023.4				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		4549.1	6384.2				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		431.5	435.4				
FEB28 ORC, m	7/		429.9	429.9				
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/		17031.4	18057.2	18215.2			
MIN APR1-JUL31 OUTFLOW, hm3	3/		7960.2	10853.6	6509.6			
UPSTREAM DISCHARGE, hm3	4/		5032.7	5007.2	5032.7			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		4719.4	6561.5	2085.0			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		430.1	435.8	425.7			
MAR31 ORC, m	7/		430.3	430.3	425.7			
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/		15789.2	16740.1	16863.2	18757.1		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		7593.2	10486.6	6142.6	5483.2		
UPSTREAM DISCHARGE, hm3	4/		5032.7	4790.9	5032.7	5269.2		
VRC APR30 RESERVOIR CONTENT, hm3	5/		5594.6	7295.3	3070.1	753.2		
VRC APR30 RESERVOIR CONTENT, METERS	6/		433.8	437.3	428.2	422.2		
APR30 ORC, Fm	7/		431.0	431.7	428.1	422.2		
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/		11702.4	12407.2	12506.5	13915.9	14365.7	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		7214.0	10107.4	5763.4	5104.0	3984.9	
UPSTREAM DISCHARGE, hm3	4/		3019.6	2887.5	3019.6	3570.8	3741.5	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		7289.1	8757.8	5034.3	3516.8	2118.6	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		437.3	440.1	432.6	429.2	425.8	
MAY31 ORC, m	7/		434.0	436.3	432.6	429.2	425.8	
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/		5455.1	5783.6	5840.1	6502.2	6718.2	6608.3
MIN JUL1-JUL31 OUTFLOW, hm3	3/		4263.4	5248.4	3936.4	3787.8	3535.6	3638.6
UPSTREAM DISCHARGE, hm3	4/		765.0	538.9	956.4	1265.1	1353.9	1430.3
VRC JUN30 RESERVOIR CONTENT, hm3	5/		8331.1	8761.6	7810.5	7308.6	6929.1	7218.4
VRC JUN30 RESERVOIR CONTENT, METERS	6/		439.3	440.0	438.3	437.3	436.6	437.1
JUN30 ORC, m	7/		439.3	440.0	438.3	437.3	436.6	437.1
BASE ECC, m	8/	440.1						
JUL 31 ECC, m			440.1	440.1	440.1	440.1	440.1	440.1

** 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/ 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 FRM REQUIREMENTS.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 3: 2014 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			17536.3	17646.9	17116.6	18027.8	17130.2	12819.6
& IN KSFD	**		8841.2	8897.0	8629.6	9089.0	8636.5	6463.2
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/		7358.6					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		3548.6					
UPSTREAM DISCHARGE, KSFD	4/		2002.4					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1772.0					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1414.5					
JAN31 ORC, FT	7/		1409.9					
BASE ECC, FT	8/	1409.9						
LOWER LIMIT, FT		1381.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		7182.0	7614.6				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		3408.6	4591.2				
UPSTREAM DISCHARGE, KSFD	4/		2053.2	2053.2				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1859.4	2609.4				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1415.8	1428.6				
FEB28 ORC, FT	7/		1410.3	1410.3				
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/		6961.3	7380.5	7445.1			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		3253.6	4436.2	2660.7			
UPSTREAM DISCHARGE, KSFD	4/		2057.0	2046.6	2057.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1929.0	2681.9	852.2			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1411.0	1429.8	1396.8			
MAR31 ORC, FT	7/	1411.8	1411.8	1411.8	1396.8			
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/		6453.5	6842.2	6892.5	7666.6		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3103.6	4286.2	2510.7	2241.2		
UPSTREAM DISCHARGE, KSFD	4/		2057.0	1958.2	2057.0	2153.7		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		2286.7	2981.8	1254.8	307.8		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1423.2	1434.7	1404.7	1385.2		
APR30 ORC, FT	7/		1414.1	1416.3	1404.7	1385.2		
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/		4783.1	5071.2	5111.8	5687.9	5871.7	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		2948.6	4131.2	2355.7	2086.2	1628.8	
UPSTREAM DISCHARGE, KSFD	4/		1234.2	1180.2	1234.2	1459.5	1529.3	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2979.3	3579.6	2057.7	1437.4	865.9	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1434.6	1444.0	1419.3	1408.1	1397.1	
MAY31 ORC, FT	7/		1423.9	1431.5	1419.3	1408.1	1397.1	
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/		2229.7	2364.0	2387.0	2657.6	2745.9	2701.0
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1742.6	2145.2	1608.9	1548.2	1445.1	1487.2
UPSTREAM DISCHARGE, KSFD	4/		312.7	220.3	390.9	517.1	553.4	584.6
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3405.2	3581.1	3192.4	2987.2	2832.1	2950.4
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1441.3	1443.5	1438.0	1434.8	1432.3	1434.2
JUN30 ORC, FT	7/		1441.3	1443.5	1438.0	1434.8	1432.3	1434.2
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 FRM REQUIREMENTS.
8/ HIGHER OF THE ARC OR CRC1 IN DOP

Table 4M (metric): 2014 Duncan Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			1.9	1.9	1.9	1.9	1.8	1.4
& IN hm3	**		1934.8	1881.9	1871.9	1934.5	1846.0	1392.8
95% FORECAST ERROR FOR DATE, IN hm3			308.9	255.2	256.9	229.6	212.7	190.8
95% CONF.DATE-31JULY INFLOW, hm3	1/		1625.9	1626.7	1615.0	1704.9	1633.3	1202.0
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		1625.9					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		156.3					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		257.2					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		553.1					
JAN31 ORC, m	7/		553.1					
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/		1593.3	1594.2				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		149.4	389.7				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		282.9	522.4				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		553.6	558.1				
FEB28 ORC, m	7/		553.6	557.6				
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/		1554.3	1555.1	1576.3			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8			
MIN APR1-JUL31 OUTFLOW, hm3	4/		141.8	382.2	138.8			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		314.3	553.8	289.3			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		554.1	558.6	553.7			
MAR31 ORC, m	7/		554.2	557.6	553.7			
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/		1456.8	1457.5	1477.7	1597.5		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		134.5	374.8	131.4	130.0		
VRC APR30 RESERVOIR CONTENT, hm3	5/		404.5	644.1	380.5	259.4		
VRC APR30 RESERVOIR CONTENT, METERS	6/		555.9	557.1	555.5	553.1		
APR30 ORC, m	7/		555.9	557.6	555.5	553.1		
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/		1094.2	1094.8	1109.5	1198.5	1226.6	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	39.6	2.8	2.8	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		126.9	268.6	123.9	122.5	120.1	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		759.5	900.7	741.1	650.7	620.3	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		562.1	564.4	561.8	560.3	559.8	
MAY31 ORC, m	7/		562.1	564.4	561.8	560.3	559.8	
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/		526.8	527.1	534.6	576.3	591.2	578.2
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		17.0	17.0	51.0	17.0	17.0	17.0
MIN JUL1-JUL31 OUTFLOW, hm3	4/		82.9	136.5	79.8	78.4	76.1	77.0
VRC JUN30 RESERVOIR CONTENT, hm3	5/		1282.9	1336.3	1272.1	1229.0	1211.6	1225.7
VRC JUN30 RESERVOIR CONTENT, METERS	6/		570.3	571.1	570.1	569.5	569.2	569.4
JUN30 ORC, m	7/		570.3	571.1	570.1	569.5	569.2	569.4
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 FRM REQUIREMENTS.
8/ HIGHER THAN THE ARC OR CRC1 IN DOP

Table 4: 2014 Duncan Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1568.5	1525.7	1517.6	1568.3	1496.5	1129.2
& IN KSFD	**		790.8	769.2	765.1	790.7	754.5	569.3
95% FORECAST ERROR FOR DATE, IN KSFD			126.3	104.3	105.0	93.9	86.9	78.0
95% CONF.DATE-31JULY INFLOW, KSFD	1/		664.5	664.9	660.1	696.8	667.6	491.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		664.5					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		63.9					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		105.1					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1814.5					
JAN31 ORC, FT	7/		1814.5					
BASE ECC, FT	8/	1850.3						
LOWER LIMIT, FT		1810.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		651.2	651.6				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		61.1	159.3				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		115.6	213.5				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1816.2	1830.9				
FEB28 ORC, FT	7/		1816.2	1829.3				
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/		635.3	635.6	644.3			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		58.0	156.2	56.7			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		128.5	226.4	118.3			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1817.8	1832.8	1816.6			
MAR31 ORC, FT	7/		1818.3	1829.3	1816.6			
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/		595.4	595.7	604.0	652.9		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		55.0	153.2	53.7	53.2		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		165.3	263.3	155.5	106.0		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1823.9	1827.9	1822.4	1814.7		
APR30 ORC, FT	7/		1823.9	1829.3	1822.4	1814.7		
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/		447.2	447.5	453.5	489.9	501.3	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	1400.0	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		51.9	109.8	50.6	50.1	49.1	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		310.4	368.1	302.9	266.0	253.5	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1844.3	1851.8	1843.3	1838.3	1836.6	
MAY31 ORC, FT	7/		1844.3	1851.8	1843.3	1838.3	1836.6	
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/		215.3	215.4	218.5	235.5	241.7	236.3
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		600.0	600.0	1800.0	600.0	600.0	600.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		33.9	55.8	32.6	32.1	31.1	31.5
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		524.4	546.2	519.9	502.3	495.2	501.0
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1871.0	1873.6	1870.5	1868.4	1867.5	1868.2
JUN30 ORC, FT	7/		1871.0	1873.6	1870.5	1868.4	1867.5	1868.2
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 FRM REQUIREMENTS.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 5M (metric): 2014 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			6.9	6.5	6.9	8.4	8.6	8.6
PROBABLE DATE-31JULY INFLOW, hm3			6858.3	6521.4	6865.6	8433.4	8576.6	8664.1
95% FORECAST ERROR FOR DATE, hm3			1894.4	1311.1	1200.3	1057.7	956.1	837.2
OBSERVED JAN1-DATE INFLOW, IN hm3			0.0	235.6	403.4	719.1	1290.3	3889.1
95% CONF.DATE-31JULY INFLOW, hm3	1/		4963.9	4974.7	5261.9	6656.7	6330.1	3937.8
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		4810.0					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		3352.8					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		4685.0					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		741.3					
JAN31 ORC, m	7/		737.9					
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/		4671.0	4830.3				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		3078.8	3139.0				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		4549.9	4450.9				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		740.5	739.9				
FEB28 ORC, m	7/		737.0	737.0				
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/		4497.3	4651.2	5067.2			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, hm3	4/		2775.4	2835.6	2446.1			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		4420.3	4326.6	3521.1			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		739.7	739.1	733.8			
MAR31 ORC, m	7/		736.2	736.2	733.8			
BASE ECC, m	9/	736.4						
LOWER LIMIT, m		699.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		4090.2	4228.5	4604.3	6050.9		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3	113.3		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		2481.8	2542.0	2152.5	2003.0		
VRC APR30 RESERVOIR CONTENT, hm3	5/		4533.8	4455.7	3690.7	2094.3		
VRC APR30 RESERVOIR CONTENT, METERS	6/		740.4	739.9	735.0	722.1		
APR30 ORC, m	7/		735.9	735.9	735.0	722.1		
BASE ECC, m	9/	736.1						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	61.0	67.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		2745.1	2835.6	3088.8	4060.6	4247.5	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		410.1	424.8	330.3	294.0	232.4	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		2178.5	2238.6	1849.1	1699.7	1445.7	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		5575.6	5545.2	4902.7	3781.2	3340.3	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		746.4	746.2	742.6	735.6	732.5	
MAY31 ORC, m	7/		742.9	742.9	742.6	735.6	732.5	
BASE ECC, m	9/	743.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.8	20.3	20.9	21.8	23.9	35.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		982.8	1010.0	1099.7	1451.1	1513.0	1401.9
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		416.4	424.8	370.8	350.0	314.8	329.2
MIN JUL1-JUL31 OUTFLOW, hm3	4/		1115.4	1137.7	993.1	937.5	843.3	881.8
VRC JUN30 RESERVOIR CONTENT, hm3	5/		6142.2	6142.2	6035.5	5628.6	5472.6	5622.0
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.5	749.5	748.9	746.7	745.8	746.7
JUN30 ORC, m	7/		749.5	749.5	748.9	746.7	745.8	746.7
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/		118.5	98.7	125.9	129.4	135.2	132.8

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: 2014 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, KAF			5560	5287	5566	6837	6953	7024
PROBABLE JAN-31JULY INFLOW, KSFD			2803.2	2665.5	2806.2	3447	3505.5	3541.3
95% FORECAST ERROR FOR DATE, KSFD			774.3	535.9	490.6	432.3	390.8	342.2
OBSERVED JAN1-DATE INFLOW, IN KSFD			0	96.3	164.9	293.9	527.4	1589.6
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2028.9	2033.3	2150.7	2720.8	2587.3	1609.5
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		1966					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1370.4					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1914.9					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2432					
JAN31 ORC, FT	7/		2420.8					
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/		1909.2	1974.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1258.4	1283				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1859.7	1819.2				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2429.4	2427.4				
FEB28 ORC, FT	7/		2418.1	2418.1				
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/		1838.2	1901.1	2071.1			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1134.4	1159	999.8			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1806.7	1768.4	1439.2			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2426.7	2424.8	2407.4			
MAR31 ORC, FT	7/		2415.3	2415.3	2407.4			
BASE ECC, FT	9/	2416.0						
LOWER LIMIT, FT		2293.4						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1671.8	1728.3	1881.9	2473.2		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000	4000		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1014.4	1039	879.8	818.7		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1853.1	1821.2	1508.5	856		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2429.1	2427.5	2411.3	2369.1		
APR30 ORC, FT	7/		2414.4	2414.4	2411.3	2369.1		
BASE ECC, FT	9/	2415.1						
		2287.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57	58.7	61	67.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1122	1159	1262.5	1659.7	1736.1	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		14484.3	15000	11664.3	10382.3	8206.7	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		890.4	915	755.8	694.7	590.9	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2278.9	2266.5	2003.9	1545.5	1365.3	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2448.9	2448.3	2436.3	2413.3	2403.2	
MAY31 ORC, FT	7/		2437.2	2437.2	2436.3	2413.3	2403.2	
BASE ECC, FT	9/	2437.6						
		2287.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.8	20.3	20.9	21.8	23.9	35.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		401.7	412.8	449.5	593.1	618.4	573
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		14705.3	15000	13093.9	12361.3	11118.1	11626.1
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		455.9	465	405.9	383.2	344.7	360.4
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2510.5	2510.5	2466.9	2300.6	2236.8	2297.9
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2459	2459	2457.1	2449.9	2447	2449.8
JUN30 ORC, FT	7/		2459	2459	2457.1	2449.9	2447	2449.8
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/		96.1	80.0	102.1	104.9	109.6	107.7

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 May 2014 forecast

Upstream Storage Corrections	**Metric (km^3)**	**English (Maf)**
Mica	8.509	6.899
Arrow	4.441	3.600
Duncan	1.724	1.397
Libby	3.399	2.756
Hungry Horse	1.643	1.332
Flathead Lake	0.617	0.500
Noxon Rapids	0.000	0.000
Pend Oreille Lake	0.617	0.500
Grand Coulee	5.344	4.332
Brownlee	0.336	0.272
Dworshak	1.949	1.580
John Day	0.195	0.158
Total Upstream Storage Corrections	28.772	23.326

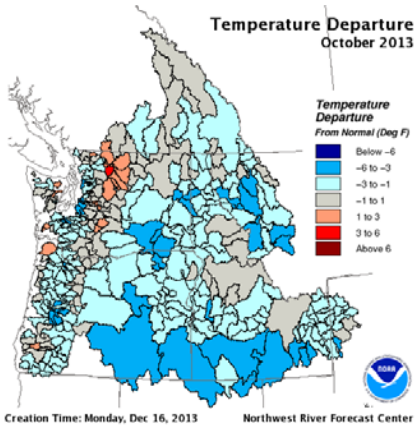
Adjusted TDA May-Aug Runoff Volume	**Metric (km^3)**	**English (Maf)**
TDA May-Aug Runoff Volume (1May Forecast)	103.149	83.624
Less Estimated Depletions	-2.061	-1.671
Less Total Upstream Storage Corrections	-28.772	-23.326
Adjusted TDA May-Aug Runoff Volume	72.316	58.627

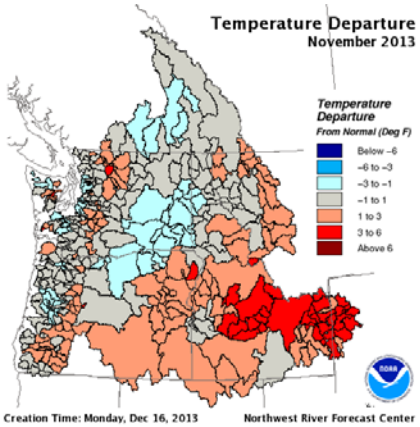
Initial Controlled Flow	**m^3/s**	**kcfs**
Determined using 'Adjusted TDA May-Aug Runoff Volume' and Chart 1 of the Flood Control Operating Plan	**10528.2**	**371.8**

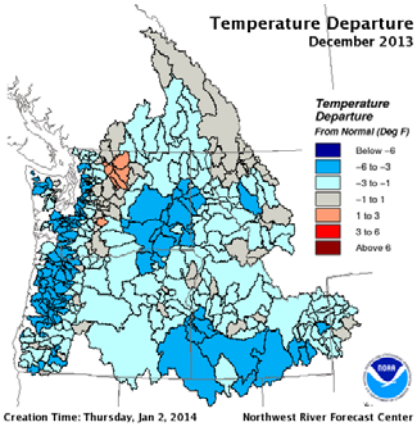
VIII - CHARTS

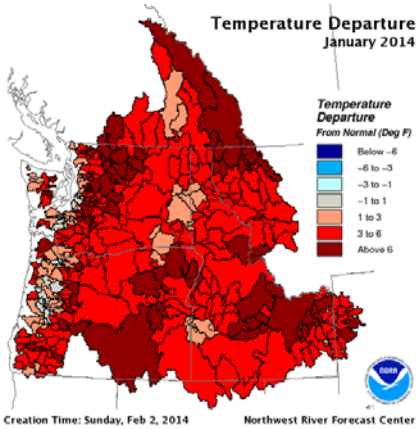
Chart 1: Pacific Northwest Monthly Temperature Departures

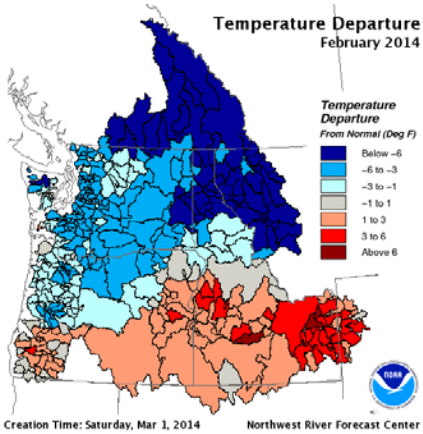
October – March











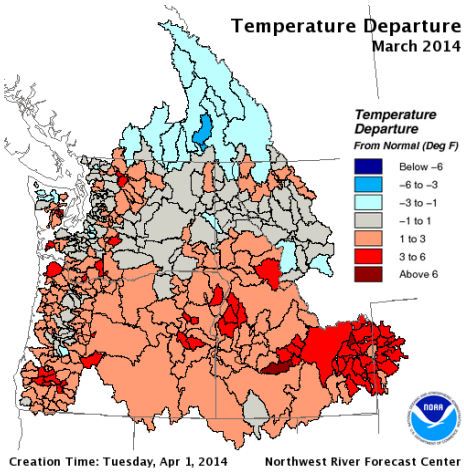
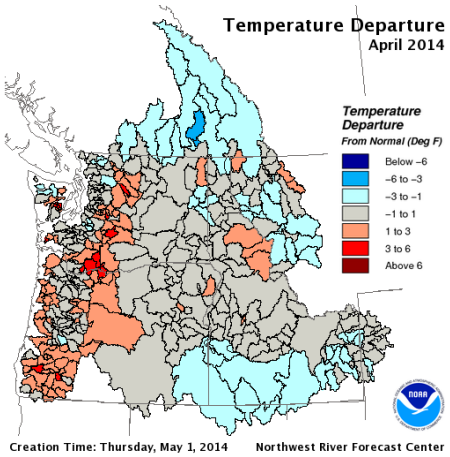
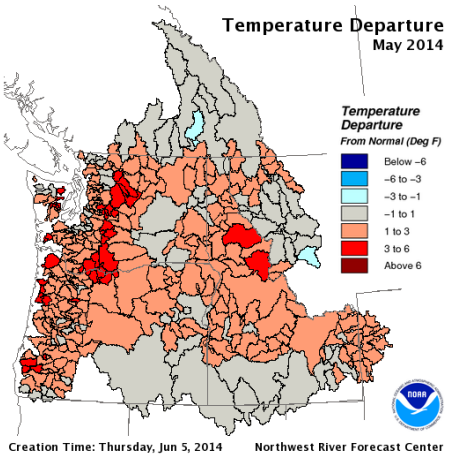
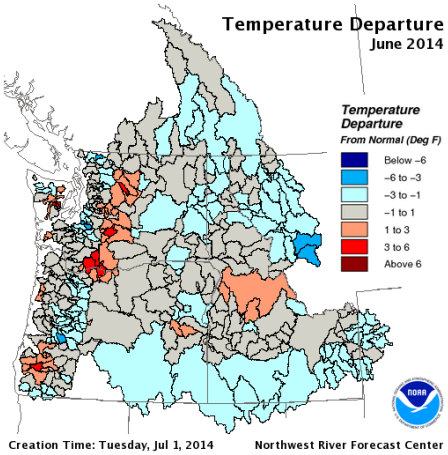
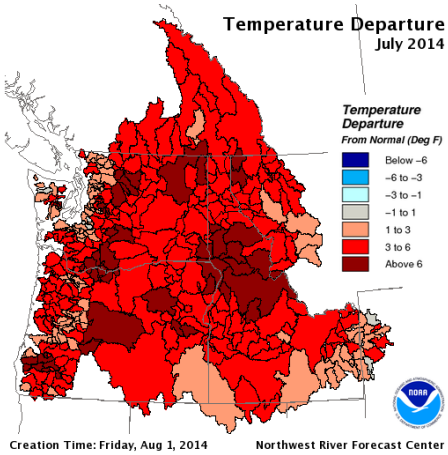


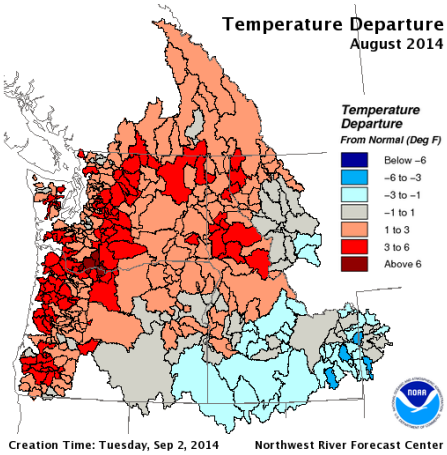
Chart 1: Pacific Northwest Monthly Temperature Departures (Continued)
April – September











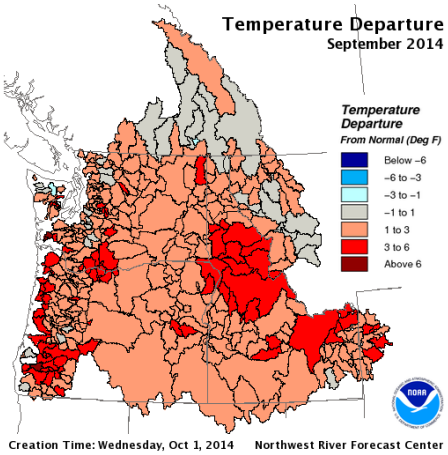
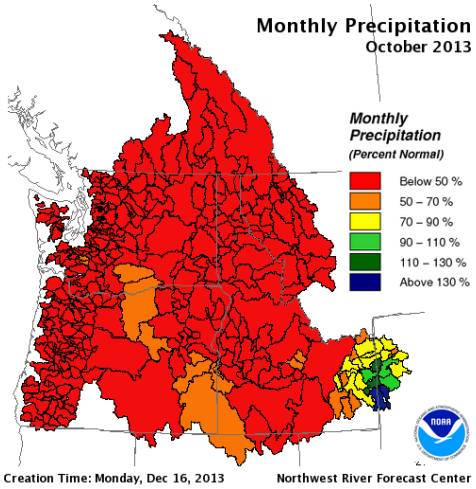
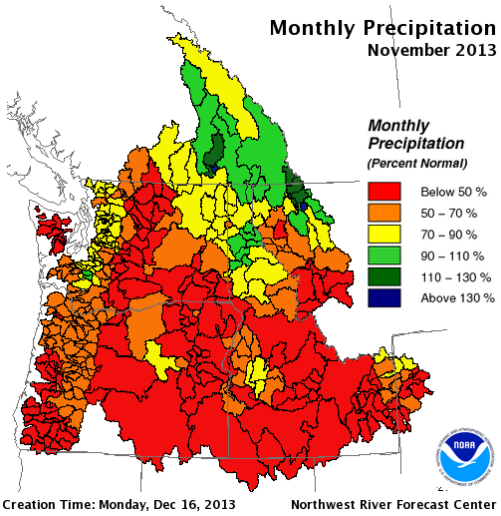
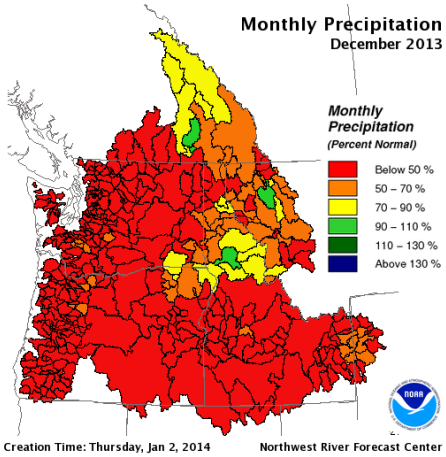
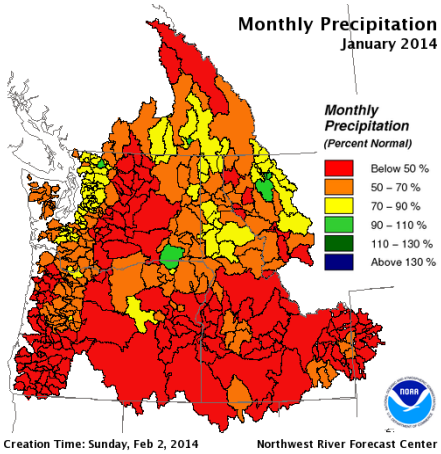


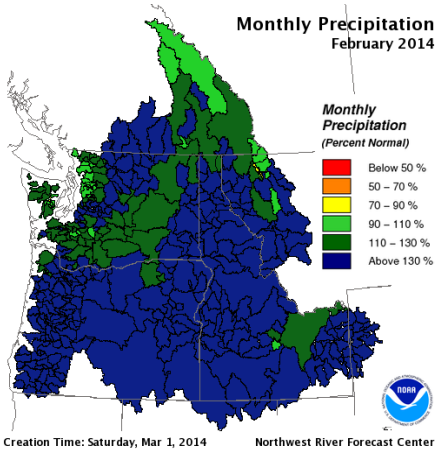
Chart 1 A: Pacific Northwest Monthly Precipitation Departures October – March











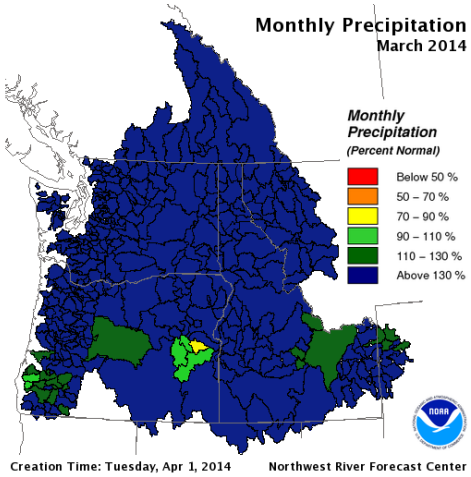
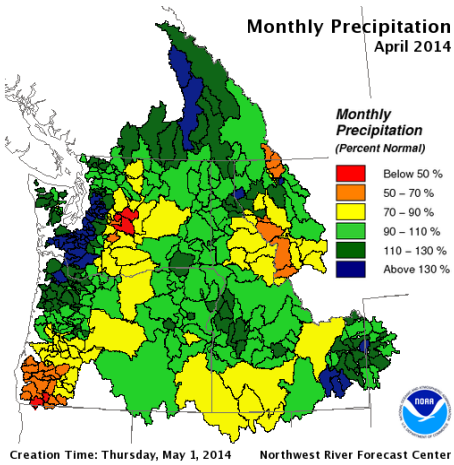
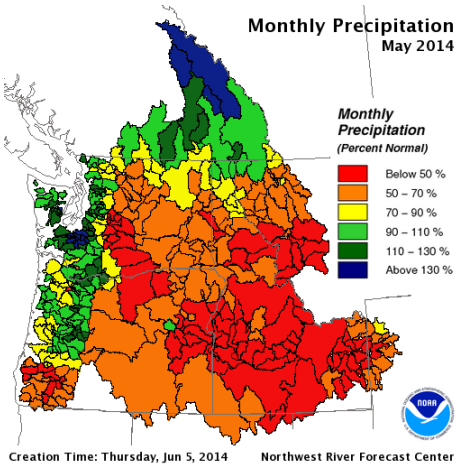
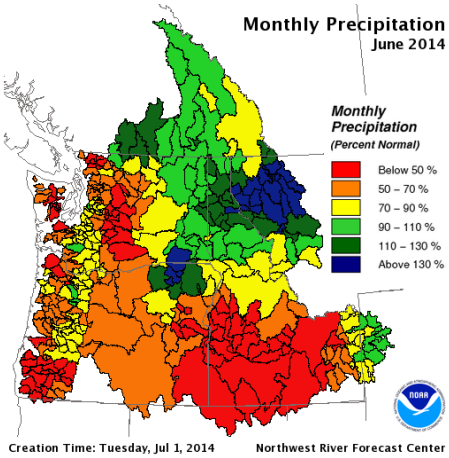
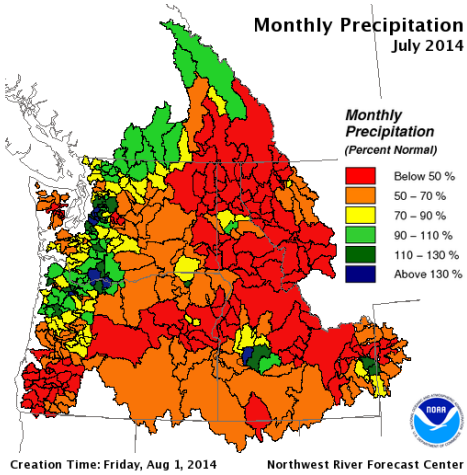


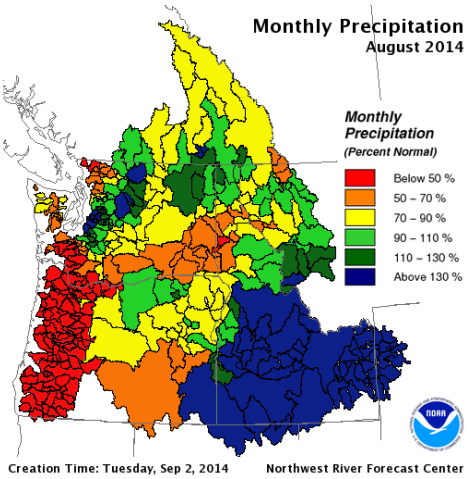
Chart 1 A: Pacific Northwest Monthly Precipitation Departures (Continued)
April – September











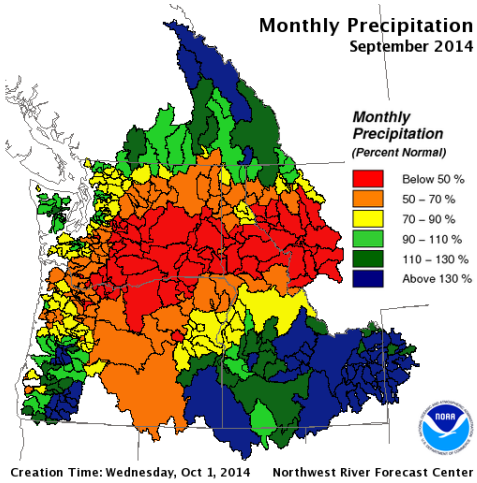


Chart 2: Seasonal Precipitation Columbia River Basin

October 2013 – September 2014

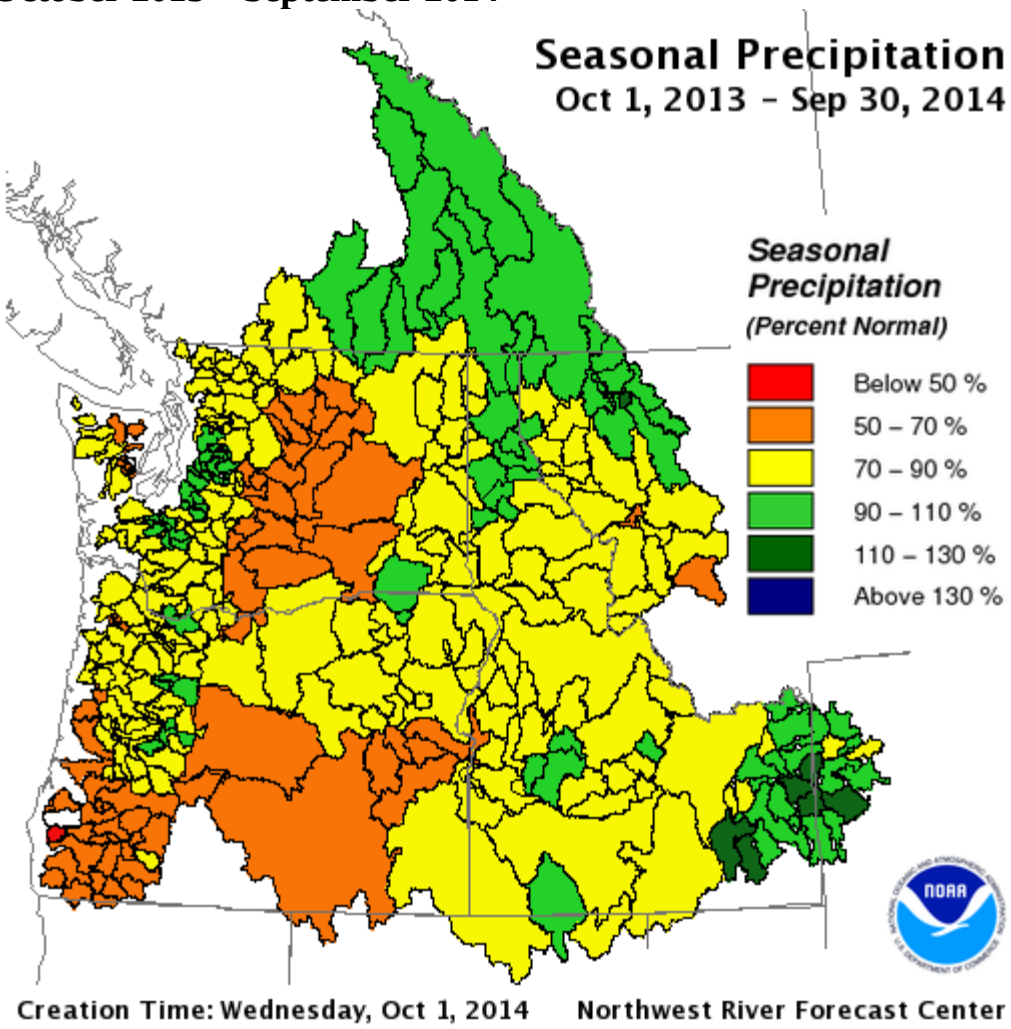


Chart 3: Columbia Basin Snowpack

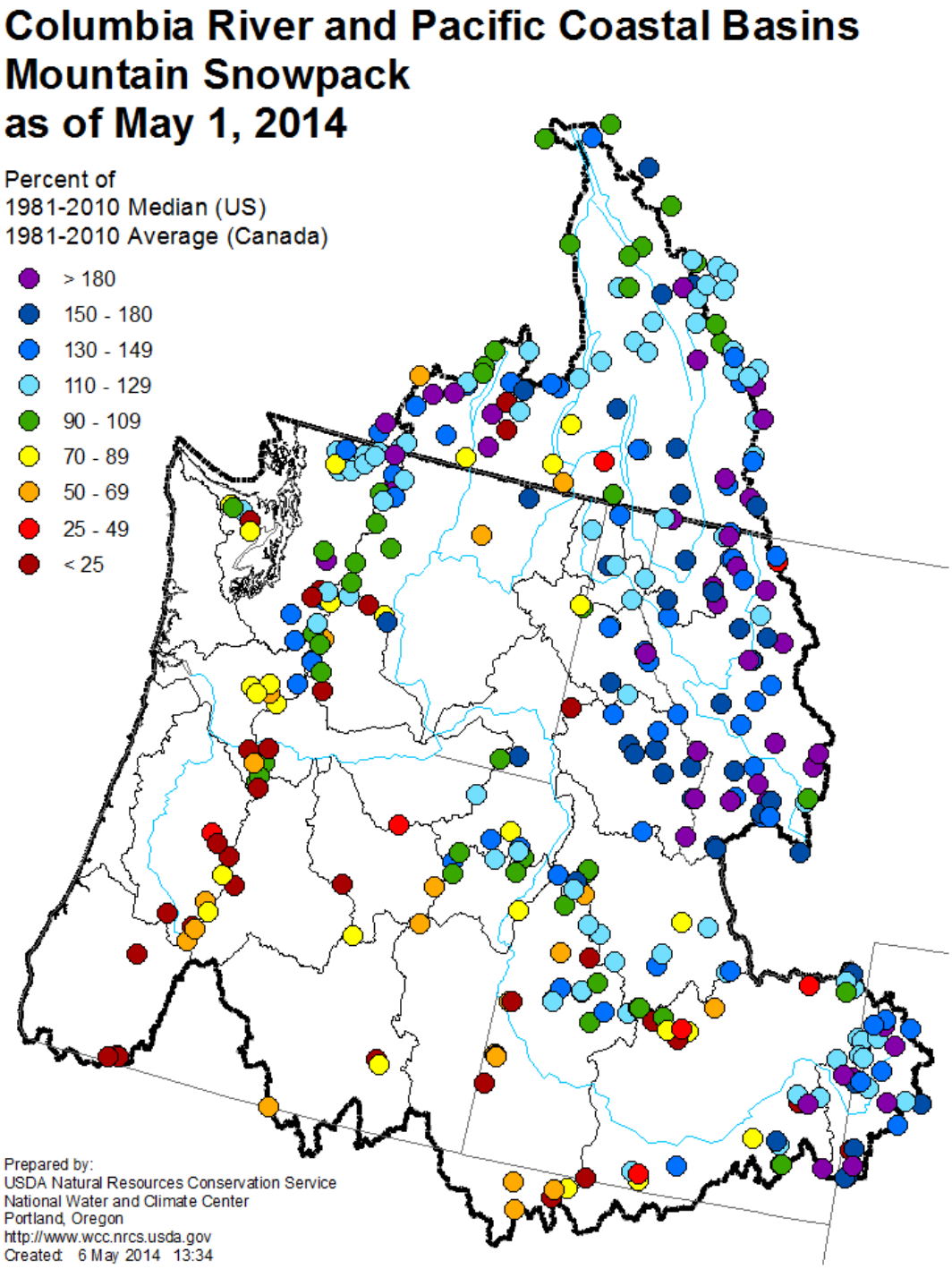


Chart 4: Accumulated Precipitation for WY 2014

At Primary Columbia River Basins

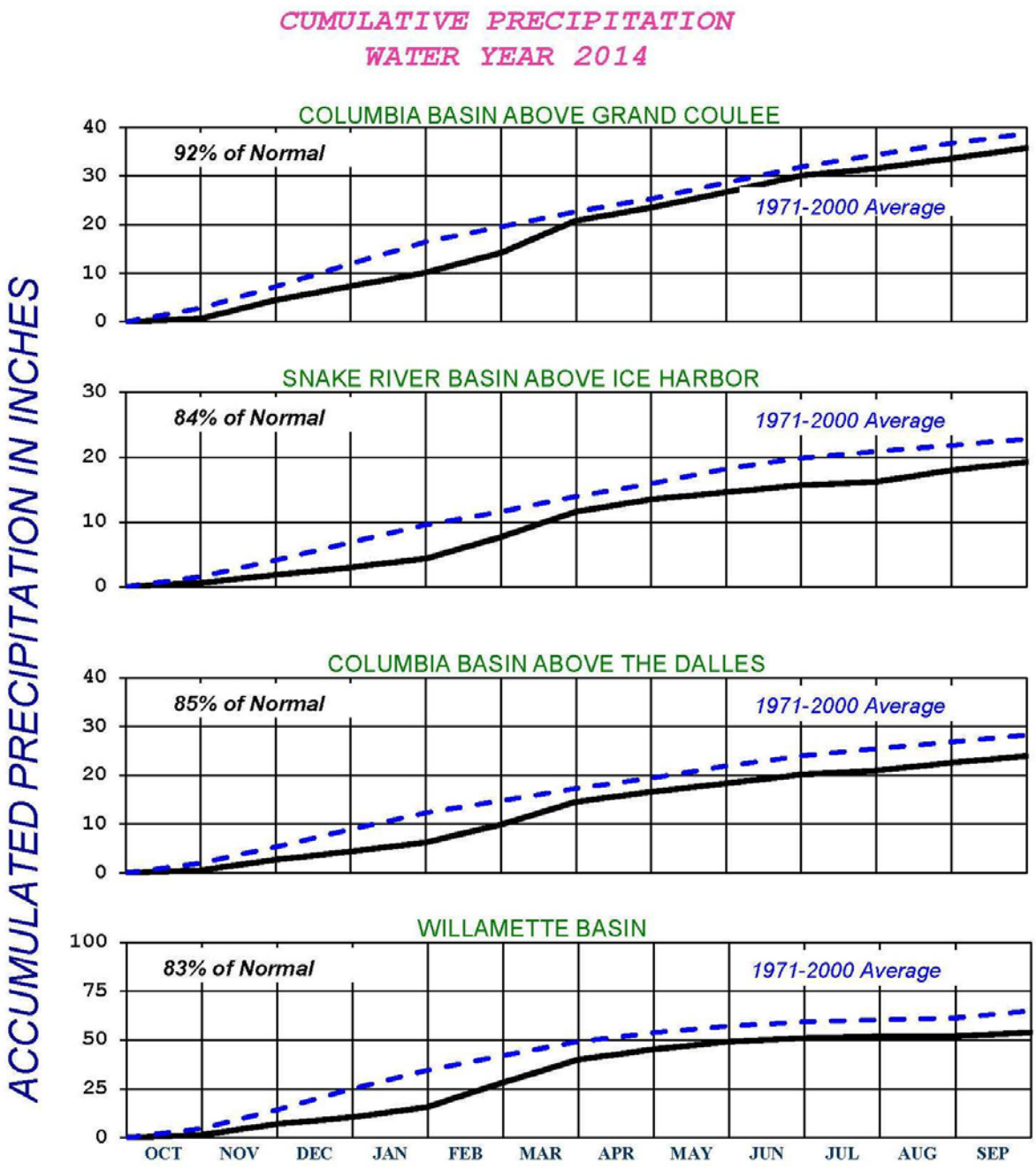
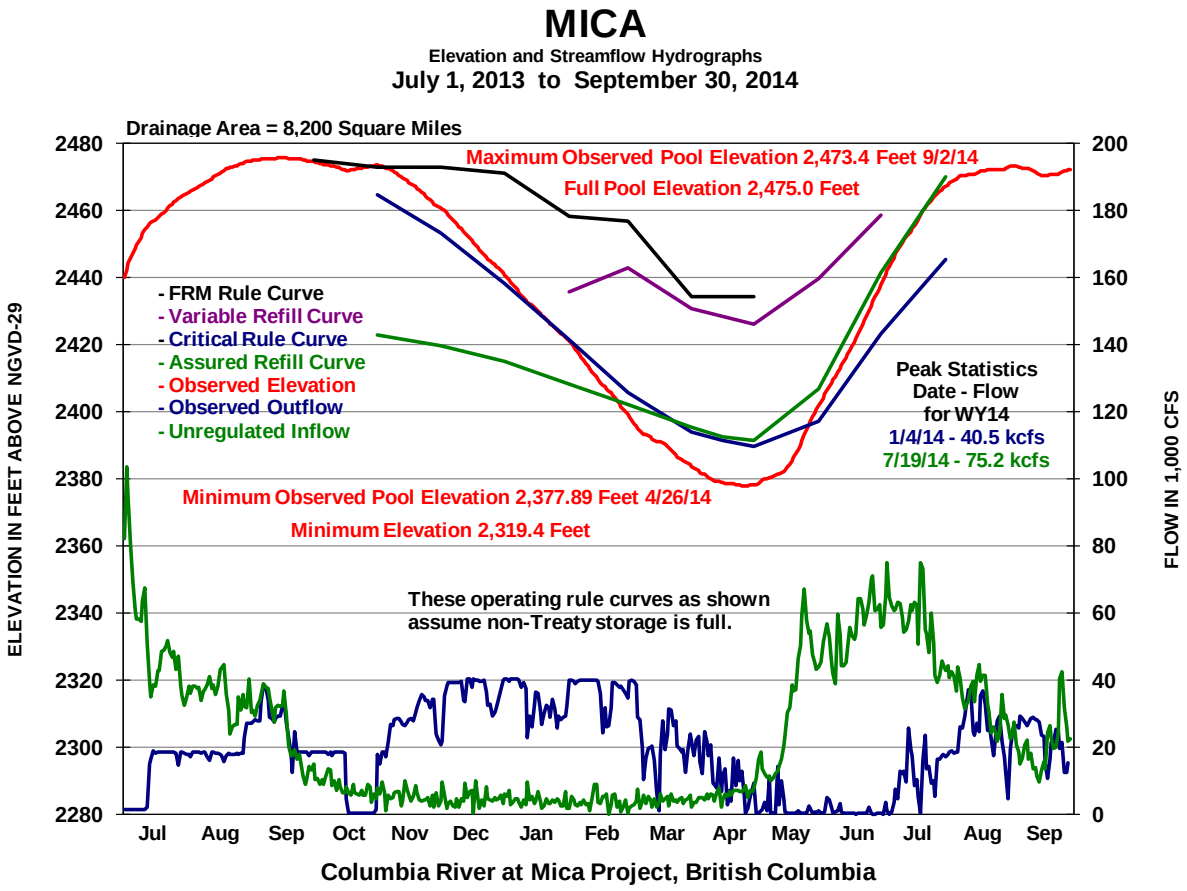


Chart 5: Regulation of Mica

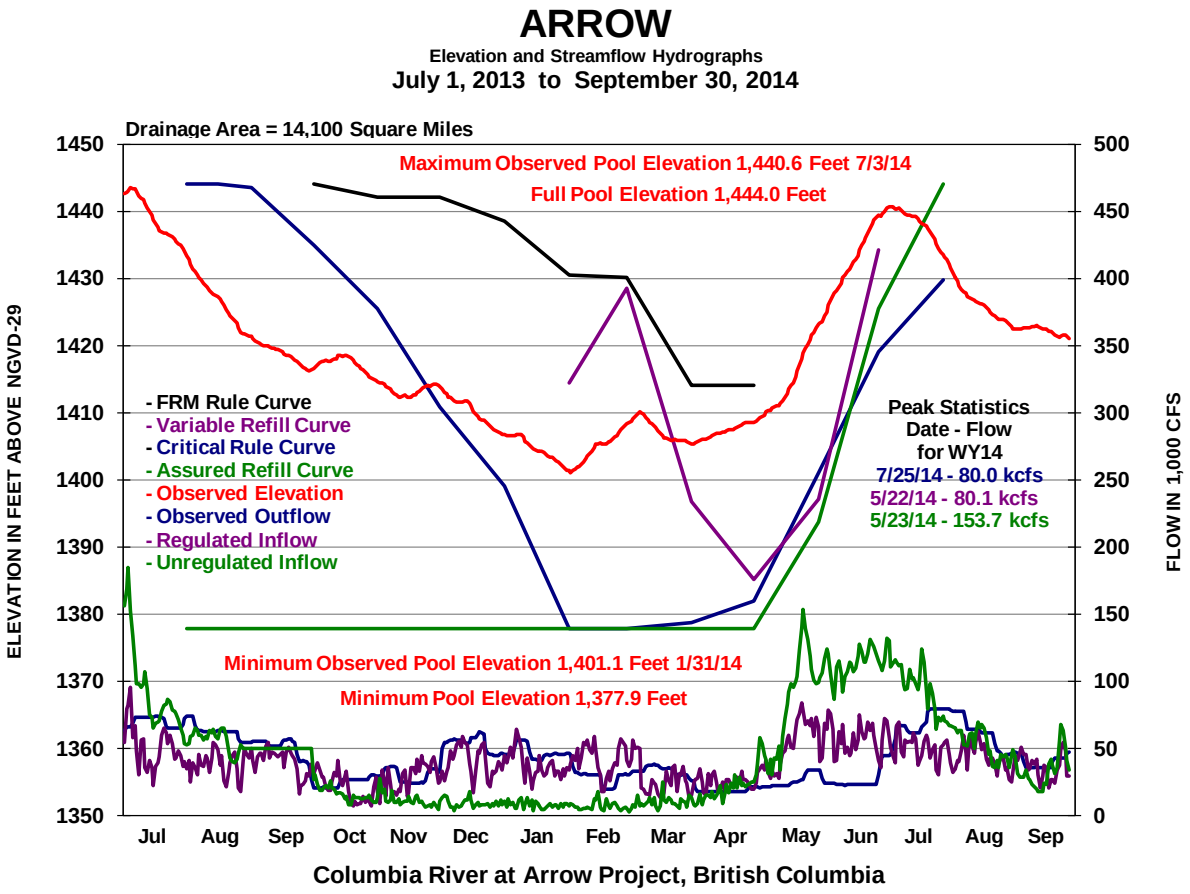
1 July 2013 – 30 September 2014



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 6: Regulation of Arrow

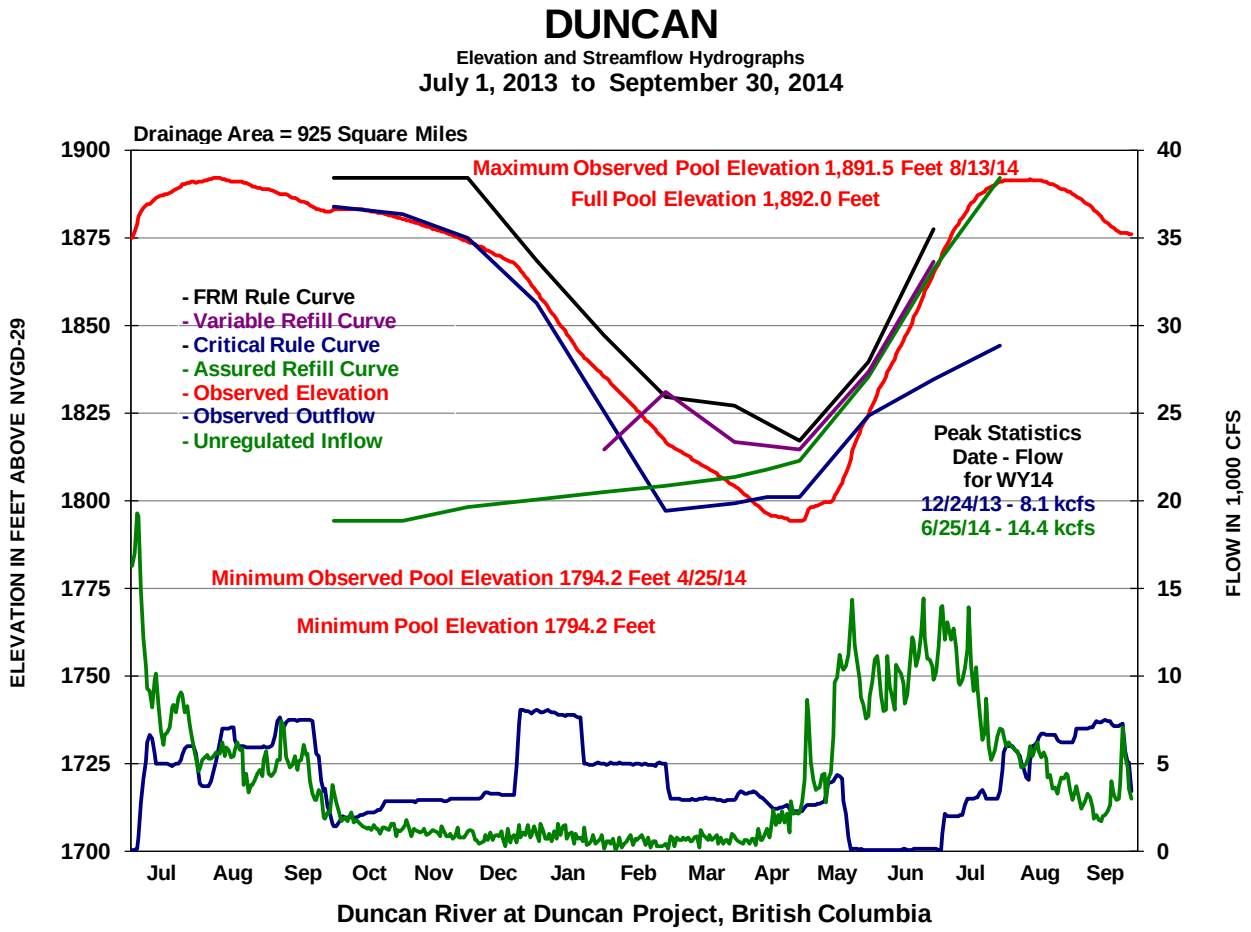
1 July 2013 – 30 September 2014



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 7: Regulation of Duncan

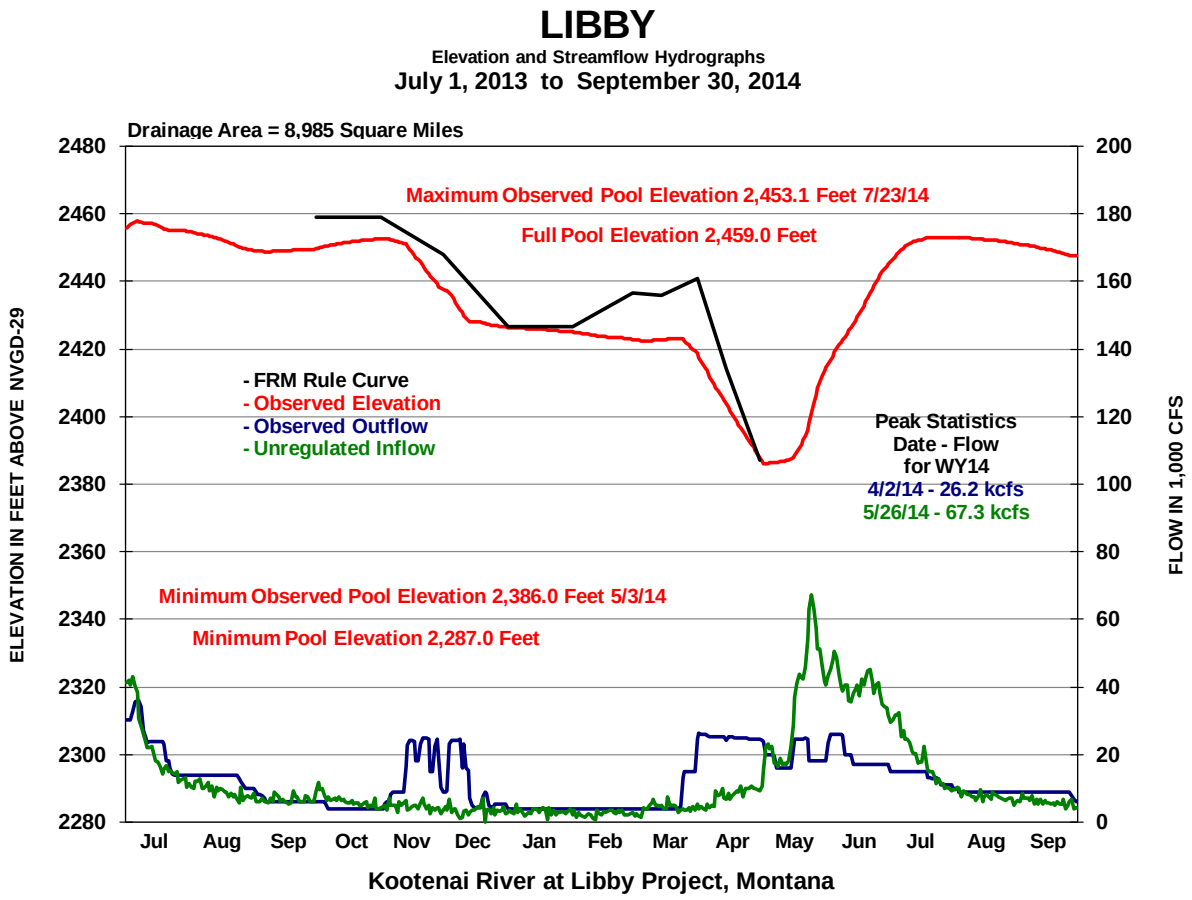
1 July 2013 – 30 September 2014



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 8: Regulation of Libby

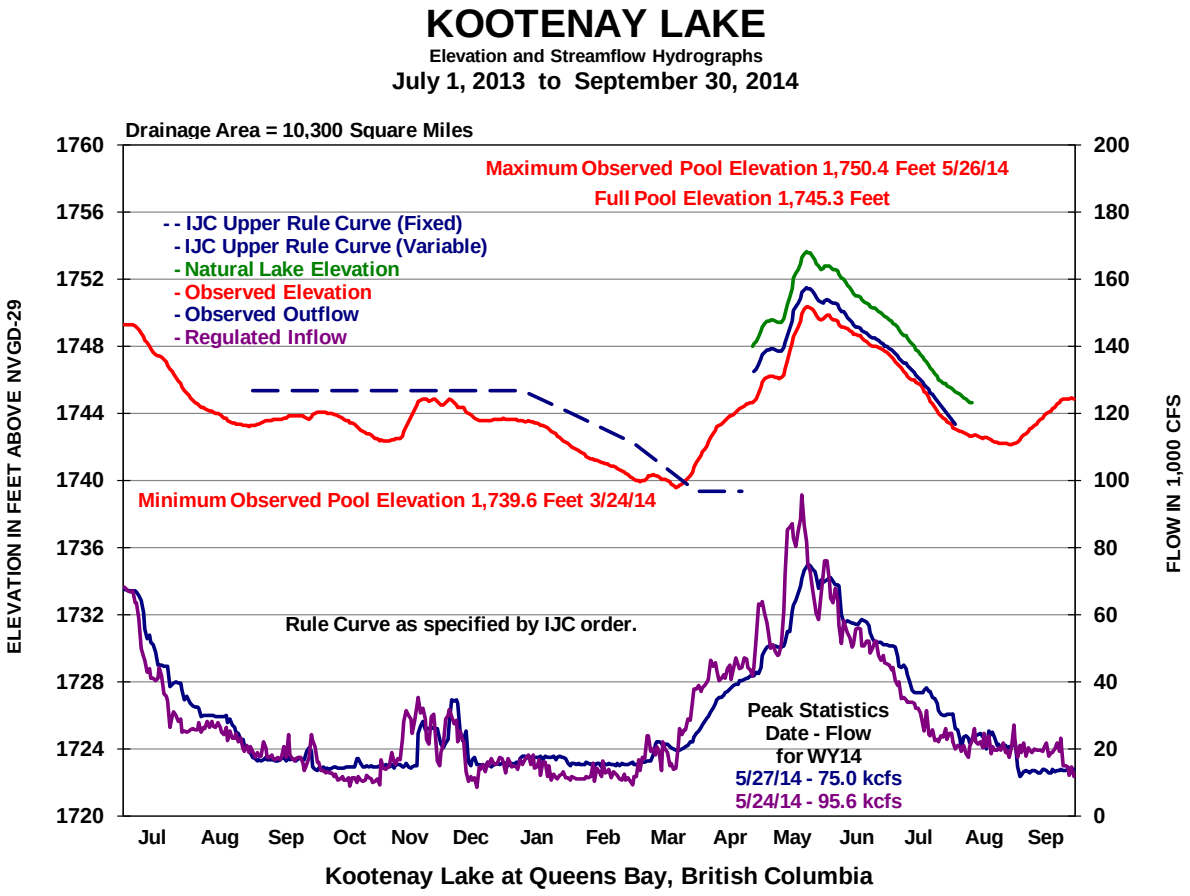
1 July 2013 – 30 September 2014



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 9: Regulation of Kootenay Lake

1 July 2013 – 30 September 2014



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 10: Columbia River at Birchbank

1 August 2013 – 30 September 2014

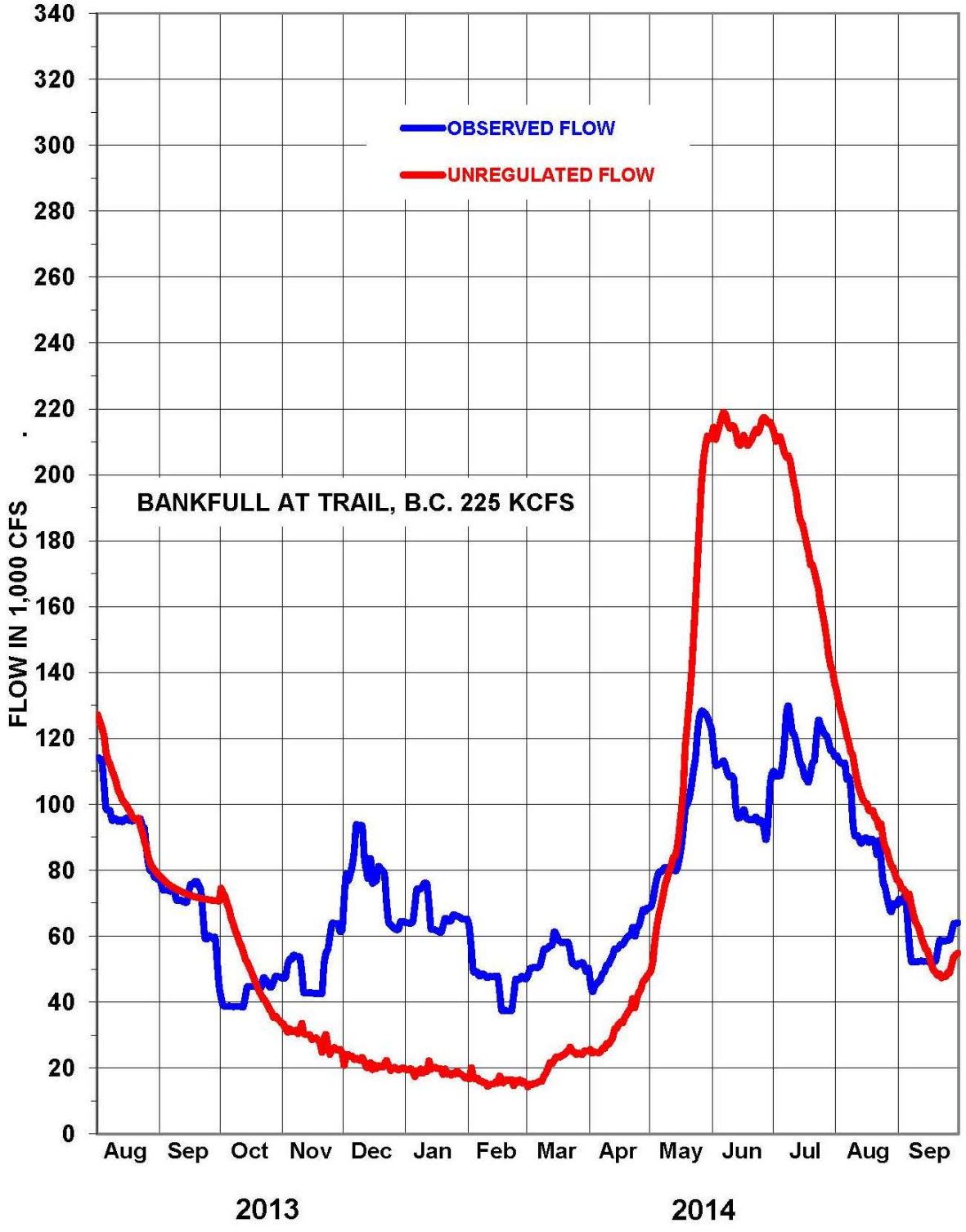
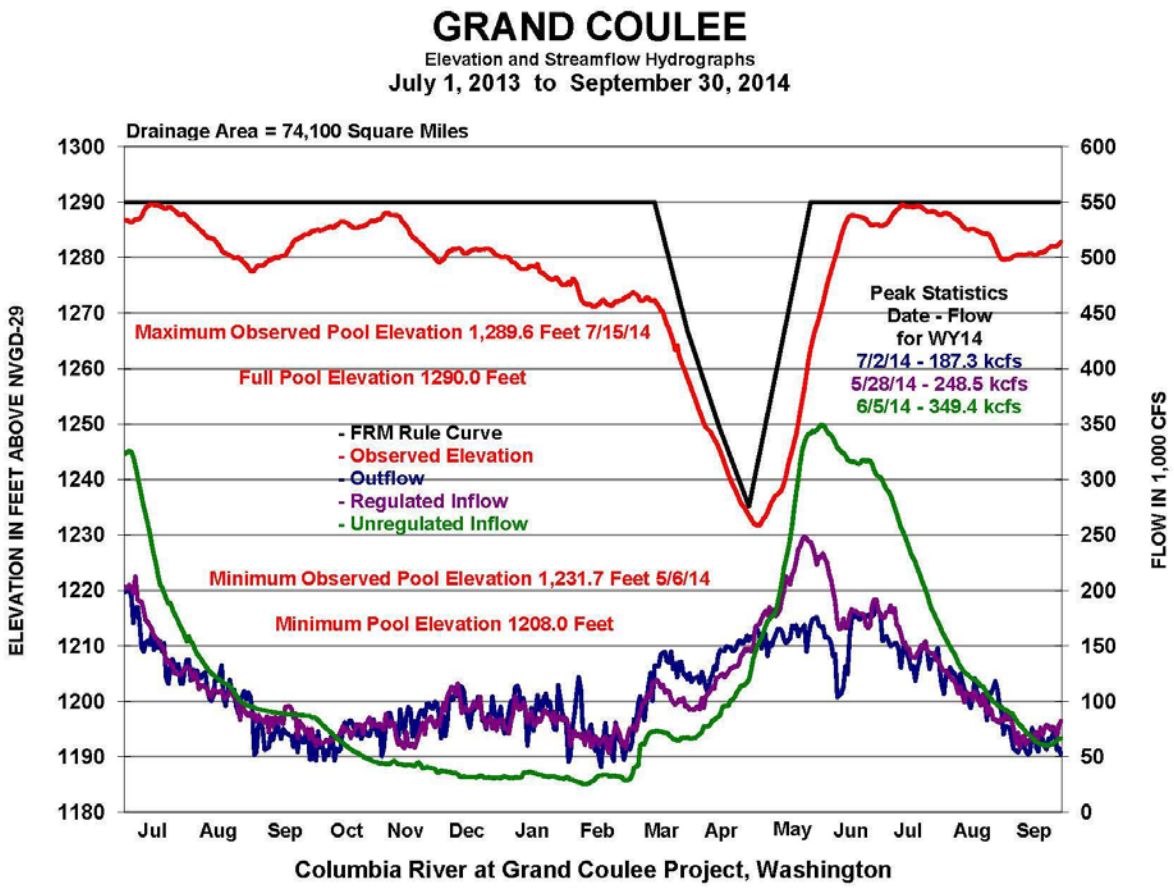


Chart 11: Regulation of Grand Coulee

1 July 2013 – 30 September 2014



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 12: Columbia River at The Dalles (Summary Hydrograph)

1 October 2013 – 30 September 2014

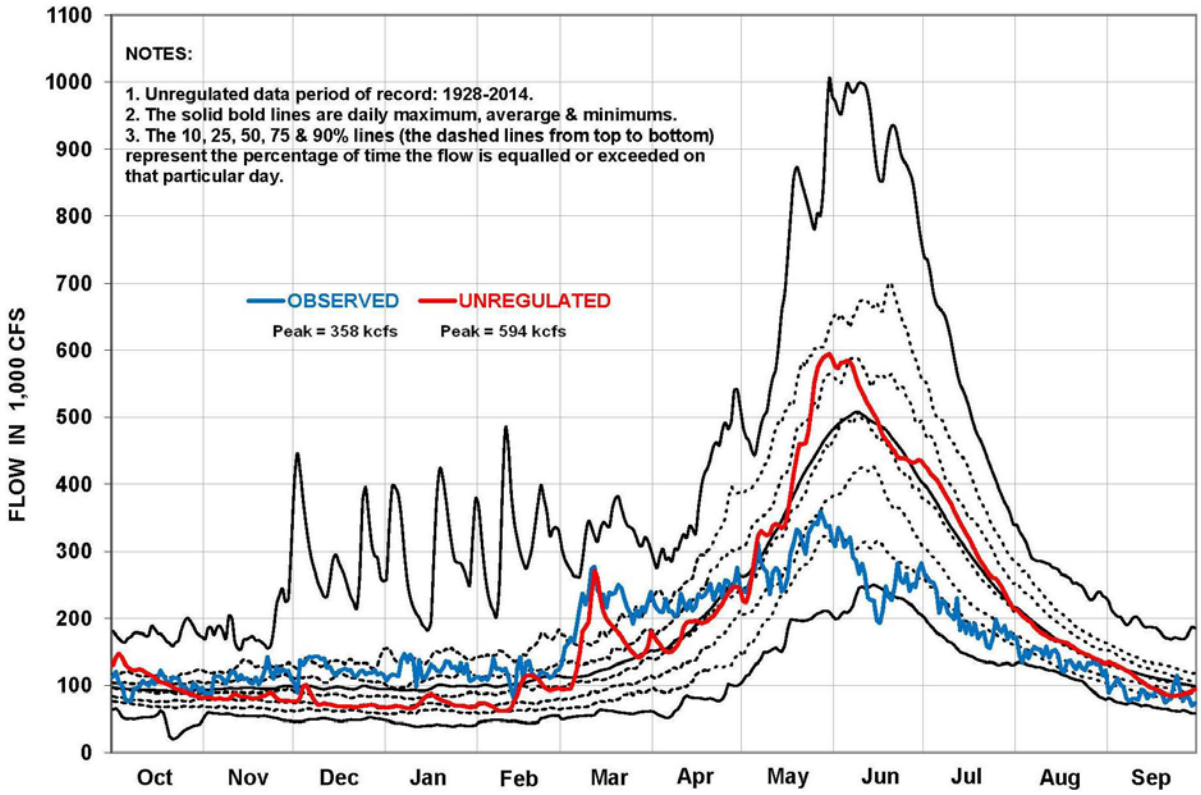


Chart 13: 2013 Columbia River at The Dalles Re-Regulation Plot

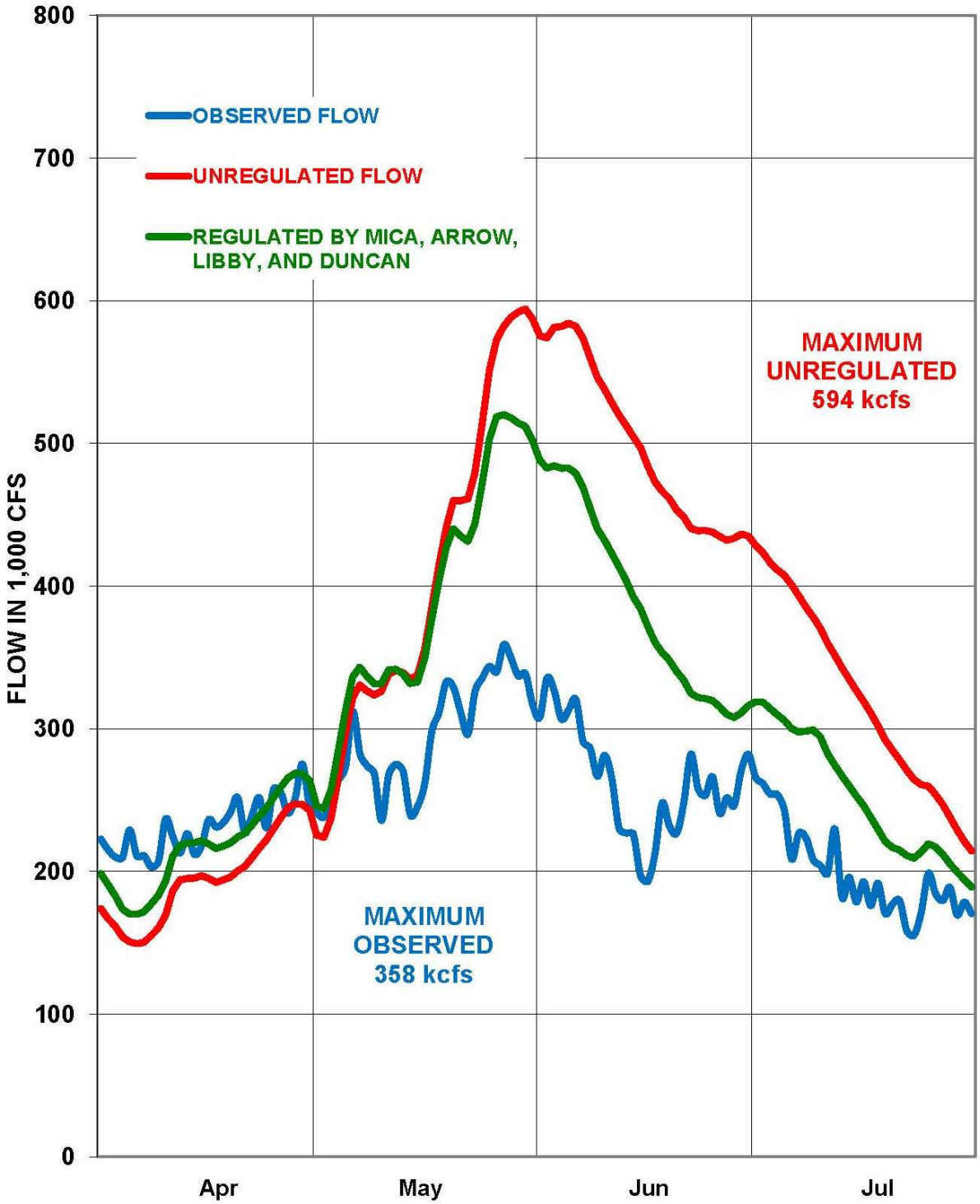
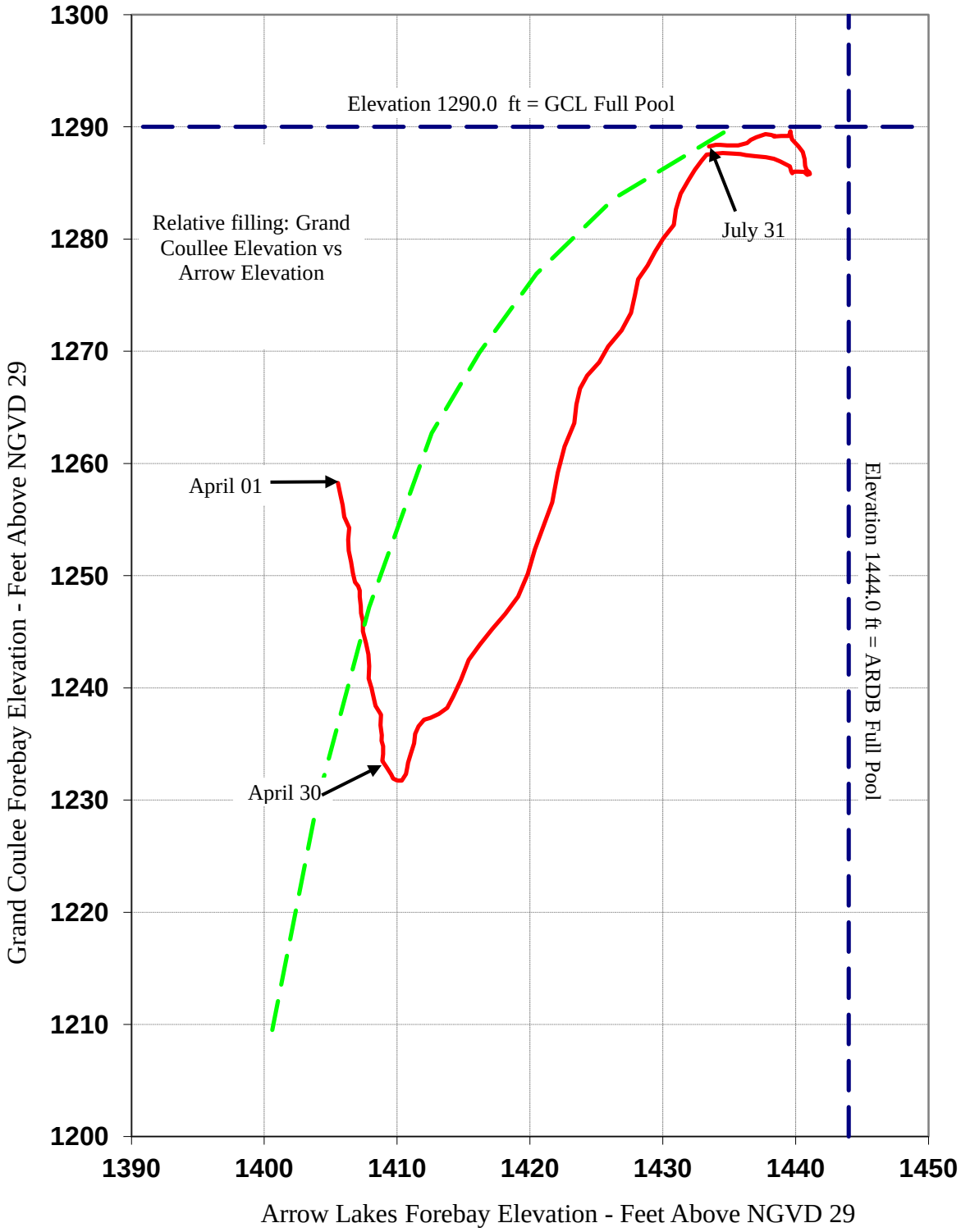


Chart 14: 2014 Relative Filling Arrow and Grand Coulee



NGVD-29 is the National Geodetic Vertical Datum of 1929