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

1 August 2015 through
30 September 2016

2016 ANNUAL REPORT

OF THE

COLUMBIA RIVER TREATY

CANADA AND UNITED STATES ENTITIES

FOR THE PERIOD

1 AUGUST 2015 – 30 SEPTEMBER 2016

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EXECUTIVE SUMMARY

General

Water Year (WY) 2016 conditions were much improved over the low flows of 2015, with the April-August runoff across the basin, measured at The Dalles, of 96.7 km^3 (cubic kilometers) (78.4 Million acre feet, Maf), or 90 percent of the 30 year average (1981 – 2010). April-August runoff in the Upper Columbia (98 percent of normal measured at Keenleyside) and Kootenai basins (92 percent of normal measured at Libby) was near average while runoff in the Snake Basin (83 percent of normal measured at Lower Granite) was below average. A strong El Niño developed in the fall and by late March, basin average snowpacks were around 107% of average, with winter basin average precipitation above average and much improved over the cool season of 2014-15. By April temperatures warmed quickly and remained warm throughout April into early May. Snowpacks quickly ripened and melted. April flows rose sharply, with the spring snowmelt peaking about 35 days earlier than usual at The Dalles on 25 April. Fortunately, snowpacks were much deeper than in 2015, but after one last peak in early June, natural flows once again dropped sharply across June and well below average in July. While the June and July average flows were near the lowest 10th percentile, they remained well above the record low natural flows observed in 2015.

For the 1 August 2015 through 30 September 2016 reporting period, the Canadian Treaty Projects were operated according to the 2015-2016 and the 2016-2017 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 (LOP), 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

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
17 December 2015	Extension of the Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2019-2020
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2020-2021
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2021-2022
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2022-2023
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2023-2024
16 June 2016	Columbia River Treaty Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2016 through 31 July 2017

Columbia River Treaty Operating Committee Agreements

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

Date Signed	Description	Authority
17 July 2015	Columbia River Treaty Operating Committee Arrow Summer Storage Agreement For the Period 1 July 2015 through 30 September 2015	Detailed Operating Plan 1 August 2014 through 31 July 2015 and Detailed Operating Plan 1 August 2015 through 31 July 2016
13 November 2015	Columbia River Treaty Operating Committee Agreement on Operation of Canadian Storage for Nonpower Uses for 1 December 2015 through 31 July 2016	Detailed Operating Plan 1 August 2015 through 31 July 2016
21 July 2016	Columbia River Treaty Operating Committee Arrow Summer Storage Agreement For the Period 23 July 2016 through 31 August 2016	Detailed Operating Plan 1 August 2015 through 31 July 2016 and Detailed Operating Plan 1 August 2016 through 31 July 2017

System Storage

The 2015-16 operating year began on 1 August 2015 with the Canadian Treaty storage at 14.7 km^3 (11.9 Maf), or 76.8 percent full. Canadian Treaty storage drafted to a minimum of 3.2 km^3 (2.6 Maf), or 16.6 percent full on 4 March 2016, and refilled to 15.5 km^3 (12.6 Maf), or 81.2 percent full, on 31 July 2016. Canadian Treaty reservoirs operated in proportional draft mode during August 2015 through January 2016, and again during June 2016 through the end of this reporting period, to meet Treaty firm loads. Throughout the operating year, composite Canadian Treaty storage targeted the Treaty Storage Regulation (TSR) study composite storage, plus any operations implemented under mutually agreed upon Supplemental Operating Agreements, including the Short Term Libby Agreement (STLA), Arrow Summer Shaping Agreement and the Nonpower Uses Agreement (NPU). 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, as well as after-the-fact changes in proportional draft points.

As in past years, the CRTOC negotiated a Nonpower Uses Agreement in order to manage Keenleyside outflows and to improve conditions for fish in both countries. Under provisions of that agreement, the U.S. Entity stored 1.2 km^3 (504 thousand second-foot-days (ksfd), 1 Maf) of flow augmentation water by the end of January 2016. Operation under the agreement helped to manage flows downstream of Keenleyside for Canadian whitefish and trout spawning protection during the January through June period. The flow augmentation water was subsequently released during July 2016 to help meet U.S. salmon flow objectives. From January until the end of July 2016, Canadian storage remained above TSR-specified levels.

The January 2016 water supply forecast for the Columbia River above The Dalles for January through July was 116.1 km^3 (94.1 Maf), or 93 percent of the 1981–2010 average. After the water supply forecast increased to 126.9 km^3 (102.9 Maf) in March, or 102 percent of the 1981-2010 average, the water supply forecasts at The Dalles then decreased going into late spring and early summer. By the June 2016 forecast, the (January-July) runoff forecast had decreased to 123.5 km^3 (100.1 Maf), or 99 percent of the 1981-2010 average. The actual January through July runoff for the Columbia River above The Dalles was 120.4 km^3

(97.6 Maf), or 96 percent of the 1981-2010 average. In contrast, the actual April through August runoff for the Columbia River above The Dalles was 96.7 km^3 (78.4 Maf), or 90 percent of the 1981-2010 average. This illustrates the relatively drier spring and early summer conditions and prior wetter conditions with strong, early runoff. The 2016 water year followed the 2015 drought year. While 2016 was not as low as 2015, it posed some operational challenges on refilling and retaining Canadian Storage due to two consecutive low flow summers.

Operations of the three Canadian projects— Mica, Keenleyside, and Duncan — and Libby in the United States are illustrated in Section VIII as Charts 5 through 8 for the 14-month period from 1 August 2015 to 30 September 2016. 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 First Critical Rule Curve (CRC1) shows the start of the proportional draft that ensures firm power demands can be met under adverse (low) 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. The Assured Refill Curve indicates the end-of-month storage content required to assure refill of the reservoir based on the 1931 historical volume of inflow during the refill period.

Treaty Project Operations

Mica (Kinbasket Reservoir)

Kinbasket reached a maximum elevation in 2015 of 750.97 m (2463.8 ft), 3.41 m (11.2 ft) below normal full pool on 15 July 2015. Similar to last year, the 2015/2016 fall and winter was warmer than normal. Despite relatively low loads, generation from Mica from September 2015 to January 2016 was 110% of normal, used to support Arrow reservoir levels during periods of deep proportional draft resulting from the 2015 drought conditions. The reservoir reached a minimum level of 729.39 m (2393.0 ft) on 1 April 2016, about 7.62 m (25.0 ft) lower than the 2015 minimum level and a maximum level of 752.03 m (2467.3 ft) on 4 September 2016, 2.35 m (7.7 ft) below normal full pool.

Hugh Keenleyside (Arrow Lakes Reservoir)

Arrow reached a maximum level of 435.47 m (1428.7 ft), 4.66 m (15.3 ft) below full pool, on 13 June 2015. Arrow reached a minimum level of 424.13 m (1391.5 ft) on 31 January 2016. By comparison, in the previous year, Arrow reached a minimum level of 423.82 m (1390.5 ft) on 30 March 2015.

Snowpack in the Columbia depleted much earlier than normal due to unseasonably warm temperatures during April 2016. This resulted in above normal runoff at The Dalles in April which quickly declined through the rest of the season. By the 1 June water supply forecast, the forecast runoff at The Dalles (April-August period) had dropped about 7.4 km^3 (6 Maf) relative to the 1 March forecast. As a result, the Columbia reservoir system in the TSR study was in proportional draft beginning in June and continuing through the reporting period of September 2016. This operation resulted in high discharges from Keenleyside across the spring/summer and produced correspondingly low summer Arrow reservoir levels. The reservoir filled to a maximum of 437.24 m (1434.5 ft), 2.90 m (9.5 ft) below full pool, on 10 June 2016. Arrow drafted across July, August and September due to continuing proportional draft reaching 430.96 m and 427.88 m (1413.9 ft and 1403.8 ft) by 31 August and 30 September 2016, respectively.

Duncan (Duncan Reservoir)

Duncan refilled to 575.04 m (1886.6 ft), 1.65 m (5.4 ft) below full, on 3 August 2015. Duncan discharges were increased during August to support Arrow levels during proportional draft operations. To enable this operation, British Columbia Hydro and Power Authority (B.C. Hydro) requested and was granted a variance from the Water Comptroller. The variance allowed Duncan to deviate from the summer recreation target of 575.46 m (1888.0 ft) between 10 August and Labour Day, as per the Duncan Water Use Plan Order.

From September 2015 through April 2016, Duncan 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. Duncan reached its minimum level, 547.21 m (1795.3 ft) on 8 April 2016. By comparison, the reservoir reached a similar minimum level of 546.90 m (1794.3 ft) on 21 April 2015. The reservoir discharge was reduced to its minimum of 2.8 m^3/s

(0.1 kcfs) in late-May to initiate reservoir refill. Releases from Duncan were held at minimum until late-July, when discharges were gradually increased to manage the rate of reservoir refill. In 2016, Duncan refilled to a maximum of 576.47 m (1891.3 ft), 0.21 m (0.7 ft) below full, on 8 August 2016. Duncan discharges were increased during August to facilitate drafting the reservoir to reach the summer recreation target of 575.46 m (1888.0 ft) between 10 August and Labour Day as per the Duncan Water Use Plan Order.

Libby (Lake Koocanusa)

Lake Koocanusa ended July 2015 at elevation 744.69 m (2443.2 ft). The project was drafted to elevation 743.93 m (2440.7 ft) at the end of August 2015. From September through April, the project was operated to meet minimum bull trout flows, and Flood Risk Management (FRM) requirements. On 19 April 2016, Libby Dam reached its minimum elevation for the year of 730.70 m (2397.3 ft) and then operated to the Variable Flow (VarQ) flood risk management rules until the start of the sturgeon pulse. On 13 May 2016, Libby began to release the sturgeon volume 1.2 km^3 (0.95 Maf) set by the May water supply forecast 7.2 km^3 (5.8 Maf, or 99 percent of average), with releases increased to 566.3 m^3/s (20.0 kcfs) for 2 days, followed by full powerhouse capacity of 750.4 m^3/s (26.5 kcfs) for 11 days. Releases were ramped down to 198.2 m^3/s (7.0 kcfs) on 14 June once the sturgeon volume was expended. Lake Koocanusa ended the month of June at elevation 743.50 m (2439.3 ft).

The operation for the rest of the summer, July through August, was to try to refill Libby as best as possible and still meet the 746.46 m (2449.0 ft) target by the end of September, as required in the NOAA BiOp and coordinated through the Technical Management Team (TMT). Libby reached its peak elevation for the summer on 18 August, 746.03 m (2447.6 ft), which was 3.47 m (11.4 ft) below full pool. Due to low inflow conditions, the project kept releases to the minimum bull trout flow of 198.2 m^3/s (7.0 kcfs) and then ramped down to 169.9 m^3/s (6.0 kcfs), the minimum bull trout flow for September. Libby elevations were 745.72 m (2446.6 ft) and 745.3 m (2445.2 ft) at the end of August and September, respectively. The 169.9 m^3/s (6.0 kcfs) in September was also the requested release from Libby to help with the ongoing in-stream habitat work for the Kootenai Tribe of Idaho (KTOI).

Treaty Benefits

Flood Risk Management Operations

Columbia River Basin projects were operated according to the May 2003 Flood Control Operating Plan. The 2016 runoff volumes were below normal across the Columbia River Basin. The regulated peak flow during the freshet at The Dalles, Oregon, was 9,389.9 m^3/s (331.6 kcfs) on 25 April 2016, and the unregulated peak flow was estimated at 13,204.1 m^3/s (466.3 kcfs) on 10 May 2016. The peak stage[1] observed during the freshet at Vancouver, Washington, was 3.26 m (10.7 ft) on 25 April 2016, and the estimated peak unregulated stage was 5.00 m (16.4 ft) on11 May 2016, while the flood stage is 4.88 m (16.0 ft).

Flood Risk Management Benefits

Water Year 2016 resulted in a quiet flood risk management season due to the slightly below average seasonal volumes. Near normal 1 April snow pack, early runoff, and below average late season precipitation across the basin resulted in no significant system or 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 unregulated runoff for the overall Columbia basin (U.S. and Canada combined) measured at The Dalles for January through July 2016 was 120.4 km^3 (97.6 Maf), 96 percent of the 1981-2010 average. 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	Date	Peak Regulated Flow
10 May 2016	13,204.1 m^3/s (466.3 kcfs)	25 April 2016	9,389.9 m^3/s (331.6 kcfs)

[1] The peak observed regulated stage at the Vancouver gage (VAPW) during the reporting period was 3.74 m (12.26 ft) which occurred on 10 December 2015 (during winter and outside the freshet).

Columbia River Stage at Vancouver, Washington

Flood Stage is 4.88 meters (16.0 feet)

Date	Peak Unregulated Stage Estimated	Date	Peak Regulated Stage
11 May 2016	5.0 m (16.4 ft)	25 Apr 2016	3.26 m (10.7 ft)

Hydroregulation by Duncan and Libby projects limited the peak level of Kootenay Lake at Queen's Bay to 532.82 m (1748.1 ft) on 27 May 2016. Without regulation from those Treaty dams, the peak level would have been approximately 533.58 m (1750.6 ft). As documented in the 2003 Flood Control Operating Plan, flood damages commence at Nelson when the Kootenay Lake elevation reaches 534.92 m (1755.0 ft). Duncan, Keenleyside, Mica and Libby projects limited the peak flow of the Columbia River at Trail, just upstream of Birchbank, British Columbia, to 3,143.2 m^3/s (111 kcfs) on 14 June 2016. Absent the dams, but with natural lake effects at Kootenay Lake, the flow would have been approximately 5,397.2 m^3/s (190.6 kcfs). For reference as per the DOP16, the bankfull flow at Birchbank is estimated to be 5,097.0 m^3/s (180 kcfs).

Power Benefits

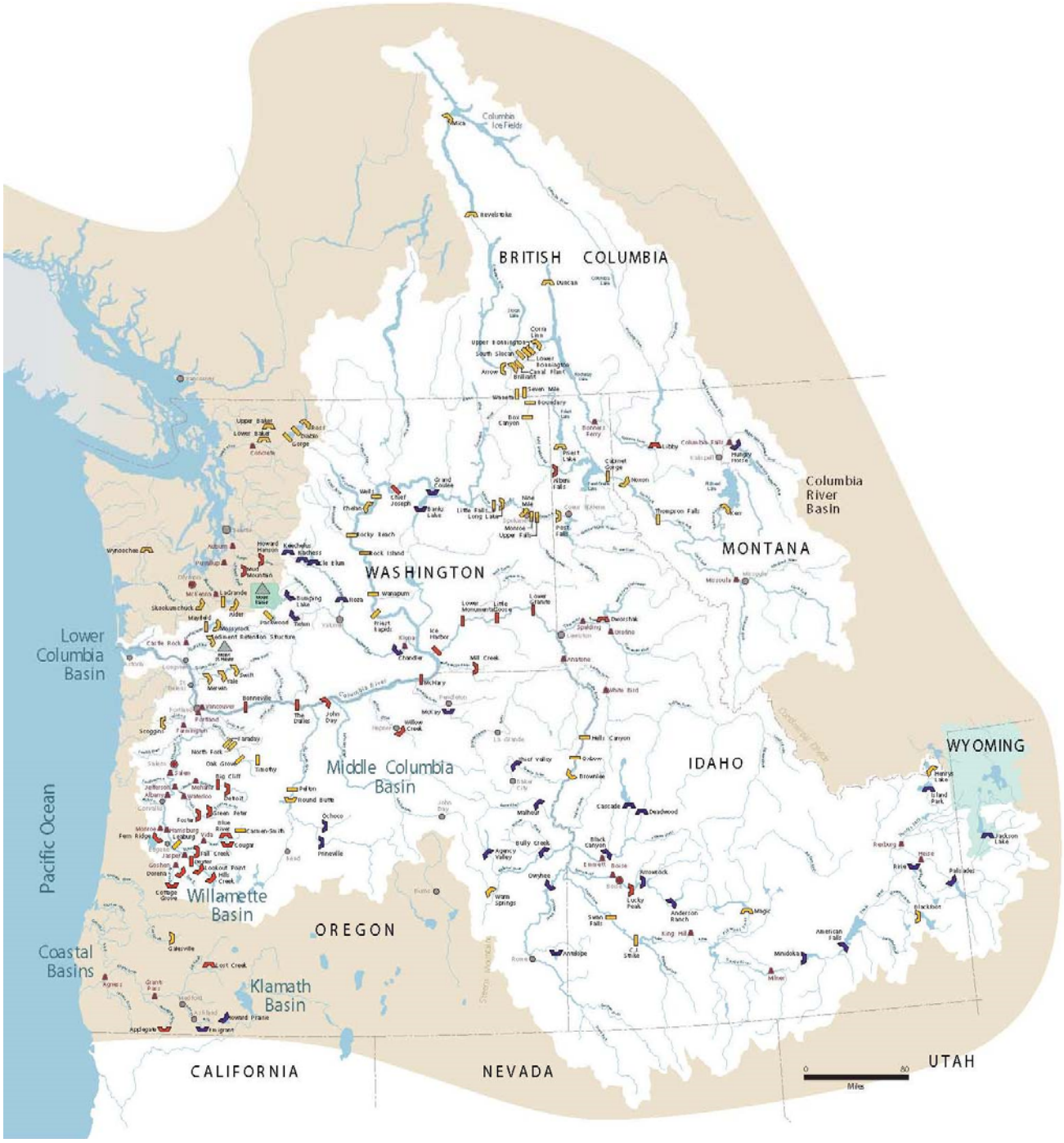
A Determination of Downstream Power Benefits (DDPB) is computed in conjunction with the Assured Operating Plan (AOP). This computation represents the optimized generation from downstream U.S. projects that could have been produced by an optimized Canadian/U.S. system. The DDPB is prepared in accordance with the Treaty and Protocol, and other Entity Agreements. The Canadian Entitlement represents one-half of the DDPB. For the period 1 August 2015 through 31 July 2016, the Canadian Entitlement amount, before deducting transmission losses, was 488.7 Average Megawatts (aMW) of energy, scheduled at rates up to 1332 MW. From 1 August 2016 through 30 September 2016, the amount, before deducting transmission losses, was 484.0 aMW of energy, scheduled at rates up to 1333 MW.

During the course of the 2015-2016 Operating Year, there was one CE delivery curtailment event. On 15 December 2015, there was a three Megawatt hour (MWh) cut in one hour which

was not due to the intertie system operating limit but due to a flow gate limit. The three MWh was successfully redelivered on 17 December 2015. 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, nonpower 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 2015-16 operating year, with and without the regulation of Canadian storage, based on the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER) that includes minimum flow and spill requirements for U.S. fishery objectives, is 110 aMW. In addition to the increase in average annual U.S. power generation, the Treaty regulation also shifted the timing of generation from the freshet period into the winter months. No quantification of this benefit was reported by the Entities.

Treaty operating plans are designed to adapt to streamflow and water supply conditions that arise and evolve over the Operating Year. Operating Plans are implemented through the TSR study which incorporates streamflows, water supply forecasts and operating parameters dependent on runoff conditions during the Operating Year, and which update the specified Canadian storage draft points twice a month. This report discusses conditions as realized for the 2015-16 Operating Year and describes the response of Canadian storage to the actual inflows and water supply conditions which occurred this year. The emphasis of the Treaty is for flood risk management and power. Other risk mitigation benefits (such as fish habitat and navigation) associated with the Treaty's flexibility to adapt to the broad array of water conditions are not addressed or quantified in this report.

Columbia Basin Map



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Acronyms and Abbreviations

AER.....Actual Energy Regulation

aMW…….. .....Average Megawatts

AOP…….....Assured Operating Plan

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

BiOp.....Biological Opinion

BG ….....Brigadier General

BPA.....Bonneville Power Administration

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

ESP .....Ensemble Streamflow Prediction

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

NPU.....Nonpower Uses Agreement

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

SSARR .....Streamflow Synthesis and Reservoir Regulation (computer simulation)

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

TMT……Technical Management Team

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

Project Naming Conventions

Hugh Keenleyside Dam

The official name of the project is Hugh Keenleyside Dam, but will be referred to as Keenleyside in the report. The official name of the associated reservoir is Arrow Lakes Reservoir, but will be referred to as Arrow in the report. i.e. “Arrow” will always refer to the reservoir and “Keenleyside” will always refer to the dam/project/facility. Note that when the Treaty was signed, the dam was referred to as “Arrow”; the re-naming to Hugh Keenleyside Dam was completed later.

Mica Dam and Powerhouse

The official name of the project/facility is Mica Dam and Powerhouse, but will be referred to as Mica in the report. The official name of the associated reservoir is Kinbasket Lake Reservoir, but will be referred to in the report as Kinbasket.

Libby Dam

The official name of the project is Libby Dam, but will be referred to as Libby in the report. The official name of the associated reservoir is Lake Koocanusa, but will be referred to in the report as Koocanusa.

Duncan Dam

The official name of the project is Duncan Dam, but will be referred to as Duncan in the report. The official name of the associated reservoir is Duncan Reservoir, but will be referred to in the report as Duncan.

I – INTRODUCTION

This annual Columbia River Treaty Entity Report is for the Water Year (WY) 2016, 1 October 2015 through 30 September 2016, with additional information on the operation of Mica, Keenleyside, Duncan, and Libby dams, as needed, to also cover the reservoir system operating year, 1 August 2015 through 31 July 2016. Also described are the power and flood risk management effects downstream in Canada and the United States (U.S.). This report is the 50th of a series of annual reports covering the period since the ratification of the Columbia River Treaty (Treaty, CRT) in September 1964.

The Entities accomplished a significant milestone with the completion of Assured Operating Plans 2020 through 2024 (AOP 2020 through AOP 2024) on 13 January 2016. These AOPs were prepared using a mid-point approach where the middle year, AOP 2022, was completed in a detailed manner using all required assumptions and procedures to produce appropriate project operating criteria and to establish Canadian Entitlement amounts. The results from the AOP 2022 studies were used for the two prior years and the two subsequent years which provided for timely completion of AOP 2020 through AOP 2024 and freed up expertise and resources to work on developing AOP methodologies for the post-2024 period when the application of flood control provisions in the Treaty changes.

Duncan, Keenleyside, and Mica in Canada were constructed as required under the CRT, and Libby 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 19.1 cubic kilometers (km^3) (15.5 Million acre-feet (Maf) of usable storage. This has been accomplished with 8.6 km^3 (7.0 Maf) in Kinbasket, 8.8 km^3 (7.1 Maf) in Arrow, and 1.7 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. No termination notices have been made to date.

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 on 1 April 1968, Keenleyside on 1 April 1969, and Mica 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 under the terms of the 'Aspects Agreement'.

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 3 February 2016 in Vancouver, B.C.

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 Scott A. Spellmon, Member
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY

Mr. Chris O'Riley, Chair
Deputy Chief Executive Officer,
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

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 Spellmon's alternate is the Deputy Division Engineer. The alternate for Mr. O'Riley is the B.C. Hydro Senior Vice President of Generation.

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

Kieran Connolly*
Vice President,
Generation and Asset Management
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY COORDINATOR

Heather Matthews**
Director,
Generation Resource Management
B.C. Hydro
Burnaby, British Columbia

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

UNITED STATES ENTITY SECRETARY

Jennifer Boyer***
Regional Coordination
Power and Operations Planning
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY SECRETARY

Jeremy Benson****
Manager, Planning and Licensing
Generation Resource Management
B.C. Hydro
Burnaby, British Columbia

* Kieran Connolly was appointed to replace Rick Pendergrass on 23 September 2016.
** Heather Matthews was appointed to replace Renata Kurschner on 1 May 2016.
*** Jennifer Boyer was appointed to replace Birgit Koehler on 21 February 2016.
**** Jeremy Benson was appointed to replace Doug A. Robinson on 30 June 2016.

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

Pamela Kingsbury, BPA, Alt. Chair
Steven B. Barton, USACE, Alt. Chair
Julie H. Ammann, USACE
Trevor Downen*, BPA

CANADIAN SECTION

Darren Sherbot, B.C. Hydro, Chair
Gillian Kong, B.C. Hydro
Herbert Louie, B.C. Hydro
Doug D. Robinson, B.C. Hydro

* Trevor Downen replaced Birgit Koehler, effective as of 20 June 2016.

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 AOP 2020 through AOP 2024;
- Completed the 1 August 2016 through 31 July 2017 DOP;
- Completed three supplemental operating agreements for Canadian storage;
- Implemented the Libby Coordination Agreement (LCA) including the July 2014 update to the Libby Operating Plan, delivery of one average megawatt (MW) of power
- Implemented the Short-term Libby Agreement (STLA) including scheduling Arrow provisional water transactions and associated financial payments;
- Completed the Libby Operating Plan for 2016-2017, 7 July 2016;
- Briefed the PEBCOM on Entity activities, and completed the 2015 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 Summer CRTOC Meeting, July 2016. Pictured are (L to R, back row), Doug D Robinson (member), Julie Ammann (member), Stephanie Smith, Tyler Llewelyn, Trevor Downen (member), Arun Mylvanahan, Robert Diffely, Tim Blair, (L to R, front row), Barbara Miller, Pam Kingsbury (U.S. Alternate Chair), Heather Matthews (Canadian Coordinator), Gillian Kong (member), Jen Boyer (U.S. Secretary), Eve James, Emma Voegeli, Peggy Racht, Herbert Louie (member), Pete Dickerson

Columbia River Treaty Hydrometeorological Committee

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

UNITED STATES SECTION

Ann McManamon, BPA Co-Chair
William Proctor, USACE Co-Chair

CANADIAN SECTION

Stephanie Smith, B.C. Hydro, Chair
Georg Jost, B.C. Hydro, Member

The CRTHC conducted bi-monthly conference calls and met in person twice during the 1 October 2015 – 30 September 2016 period:

Meeting 77: 8 March 2016, BPA
Meeting 78: 15 September 2016, B.C. Hydro

The 2015 CRTHC Annual Report was completed in December 2015 and distributed prior to the end of the year.

Forecasting

The CRTHC can agree to alter inputs to the prescribed Treaty water supply forecasting procedures if there is a strong justification and agreement that one of the inputs is unduly influencing the forecast results. The committee has a procedure to review any proposed changes and decide whether the change is considered to be justified. There was one deviation requested by B.C. Hydro in the December 2015 forecast which impacted both the Mica and Duncan forecasts. Golden Airport reported a precipitation value that was deemed unreliable. Therefore, B.C. Hydro estimated a value for that site that better reflected basin conditions. CRTHC agreed that the estimated value for Golden Airport precipitation was a better alternative.

In December, there are a number of operational decisions that require water supply forecasts. All of the treaty projects (Mica, Arrow, Duncan and Libby) have an approved water supply forecast available for use in December. In previous years, when water supply information was needed at The Dalles in December, that information would be derived from the most recently adopted modified flow record (currently 80-years, 1929-2008). However, recently, the National Weather Service has begun generating a water supply forecast in the month of December. At the September 2015 CRTOC meeting, the operating committee adopted the use of The Dalles Ensemble Streamflow Prediction (ESP)-generated water supply forecast for use in December water management decisions. The POP documentation was updated to reflect this change.

For the past few years, the Northwest River Forecast Center (NWRFC) has produced three ESP forecasts on a nearly daily basis for various forecast points, each differentiated by the number of days of deterministic weather forecasts used to initialize the forecast. The three initializations currently used are the 10, 5, and 0 days of weather forecast. The CRTHC recommended that the ESP forecast with 5 days of a short-term forecast included be adopted for Treaty purposes and for operational decisions on the Columbia River system. In order to make water supply and flood risk management information available to the region and for use in treaty coordination sooner in each month, the committee also recommended using the ESP forecast prepared on the 3rd working day of each month, rather than the 5th working day. In the 27 September 2016 CRTOC meeting, the CRTHC presented these recommendations for the upcoming year, and the recommendations were approved for a one year trial.

At the request of the Treaty VarQ team, B. C. Hydro has looked into preparing a forecast procedure for Kootenay Lake inflow which can be used in conjunction with the Libby forecast procedure and provide additional information to inform flood risk management decisions that is not already captured in the Libby forecast procedure. It is not anticipated that this new procedure will replace the existing procedure that B. C. Hydro currently uses, but rather provide supplemental information.

Data Exchange

Now that B. C. Hydro and BPA are both on the same software modeling platform, the agencies are exploring ways to more efficiently exchange streamflow data for the bi-monthly Actual Energy Regulation (AER) coordination.

Stations

The CRTHC routinely reviews the basin gauging network for adequacy. At this time, the CRTHC believes that with the addition of the stations described below, the station network is adequate for Treaty purposes. CRTHC added clarification on how it comes to this determination in the 2015 CRTHC Annual Report.

Last year, the precipitation at Fernie, B.C., was automated to make the data more reliably available. That gage has been reporting reliably since December 2015, and the information has been especially useful for the Libby forecast procedure.

After continual problems with data availability with the stations at Porthill and Bonners Ferry, Idaho, BPA worked with the National Weather Service to have those stations automated with more robust equipment. The installation of the new equipment is expected to occur in the fall of 2016.

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.	Dr. Niall O'Dea, 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
Steve Oliver, Alternate Portland, Oregon	Les MacLaren, Alternate Victoria, British Columbia

The following serve as Secretaries to the Board:

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

Under the CRT, the PEB is to assemble records of flows of the Columbia River and the Kootenay River at the international boundary. The PEB is also to report to both governments if there is substantial deviation from the hydroelectric 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 2-3 February 2016 in Portland, Oregon. The Entities and the PEB met to discuss the current status of the CRT Review, the preparation and implementation of operating plans, the Libby VarQ issues and other topics requested by the PEB. Regarding AOP 2020 and subsequent AOP's pre-briefs were held 3 February 2016 that provided considerable background on the significant work efforts by the team in reaching agreement on assumptions and tools used in the development of all five AOP's (AOP 2020-24). By reaching consensus on these issues the team successfully completed the required documents ahead of schedule. These documents represent the first assessments of the Columbia River basin as a "capacity-limited" system. Canadian concerns with Libby VarQ operations were discussed in detail. All agreed that it is in the best interests of both countries to continue in the collaborative efforts / studies to pursue resolution of the issues associated with VarQ. The STLA was extended for one year allowing additional time to complete studies.

PEB Engineering Committee

The PEB has established the PEBCOM to assist in carrying out its duties. The PEBCOM met with the Operating Committee on 21 October 2015 in Vancouver, BC. The members of PEBCOM at the end of this reporting period were:

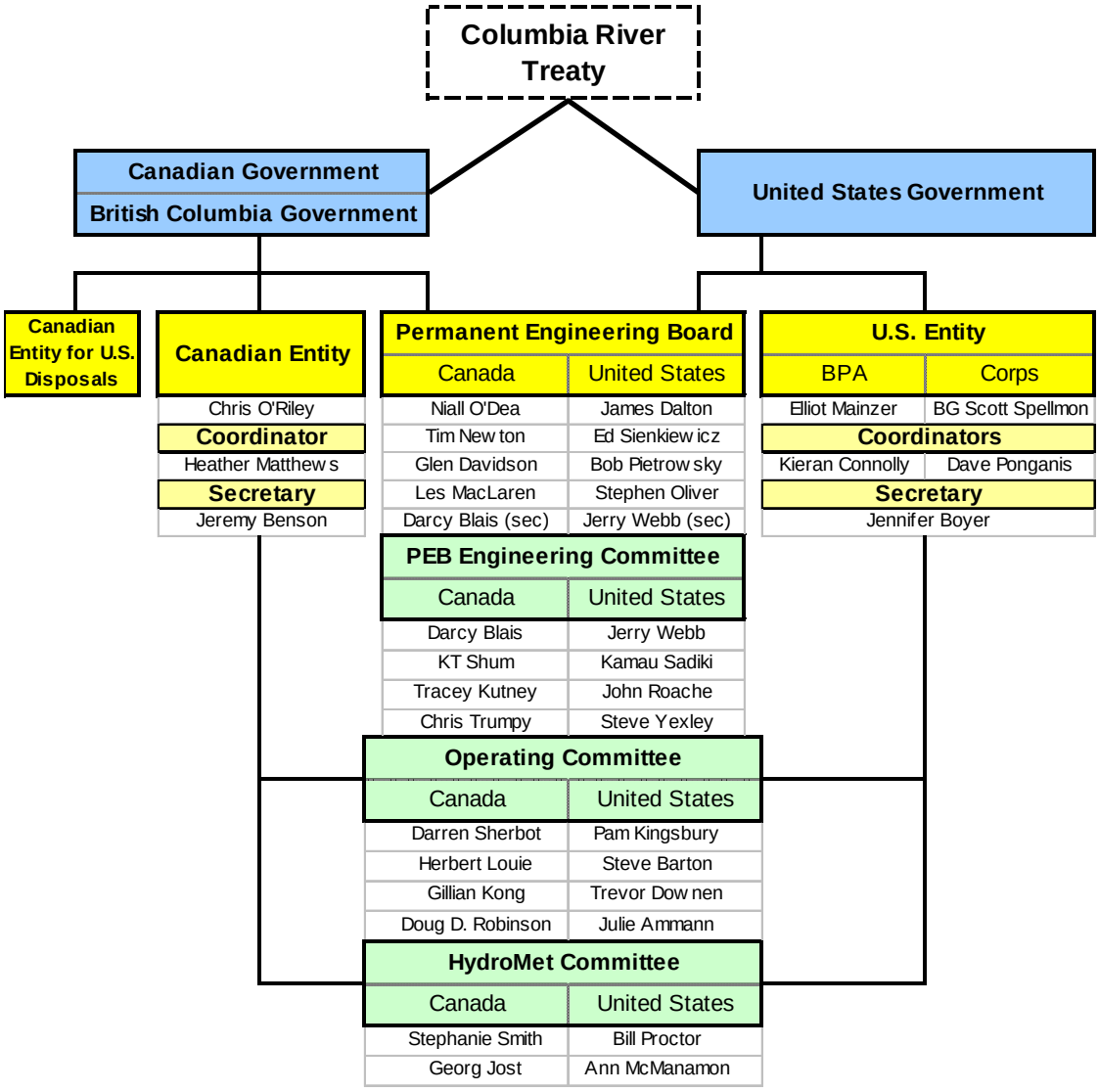
UNITED STATES SECTION	**CANADIAN SECTION**
Jerry W. Webb, Chair Washington, D.C.	Darcy Blais, Chair Ottawa, Ontario
Steve Yexley, Member** Lakewood, CO	Tracey Kutney, Member* Ottawa, Ontario
Kamau B. Sadiki, Member Washington, D.C.	K.T. Shum, Member Victoria, British Columbia
John Roache, Member Boise, Idaho	Chris Trumpy, Member Victoria, British Columbia

*Ms. Kutney was appointed to the PEBCOM effective 17 Nov 2015.
**Mr. Yexley's appointment behind Mr. Tom Patton is currently pending; the position was vacated on 4 March 2016.

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, Canadian Section Chair Gordon Walker, U.S. members Rich Moy and Dereth Glance, and the other Canadian members are Benoit Bouchard and Richard Morgan. 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.

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 2015-2016 Operating Year from 1 August 2015 through 31 July 2016. The operation of Canadian storage was guided by the 2015-2016 DOP and supplemental operating agreements. The DOP required a semi-monthly Treaty Storage Regulation (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 2015-2016 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period from 1 August 2015 through 30 September 2016.

Assured Operating Plans

During the reporting period, the Entities completed AOP 2020 and four subsequent AOPs through AOP 2024. The CRTOC conducted a careful review of the 2020-2024 AOP load, resource and other data assumptions and completed the AOP for the middle year, AOP 2022. The Entities agreed that the results of the AOP 2022 suite of studies would be used for the two prior years (AOP 2020 and AOP 2021) and for the two subsequent years (AOP 2023 and AOP 2024). Thus, all five AOPs were signed by the Entities in January 2016. The 2019-2020 through 2023-2024 AOPs and Determination of Downstream Power Benefits (DDPB) are not precedent-setting for future AOP or DDPB studies and are not to be construed as representing a past practice or procedure or constituting a Treaty modification to or revised interpretation of the Treaty.

Determination of Downstream Power Benefits

For each operating year, the 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). In conjunction with the 2019-2020 through 2023-2024 AOP studies, the Entities completed studies for the 2019-2020 through 2023-2024 DDPBs.

Canadian Entitlement for the Operating Year

For the period 1 August 2015 through 31 July 2016, the Canadian Entitlement (CE) amount, before deducting transmission losses, was 488.7 Average Megawatts (aMW) of energy, scheduled at rates up to 1332 MW capacity. From 1 August 2016 through 30 September 2016, the amount, before deducting transmission losses, was 484.0 aMW of energy, scheduled at rates up to 1333 MW capacity. The CE obligation was determined by the 2015-2016 and 2016-2017 AOP/DDPBs.

During the course of the 2015-2016 Operating Year, there was one CE delivery curtailment event. On 15 December 2015, there was a three Megawatt hour (MWh) cut in

one hour which was not due to the intertie system operating limit but due to a flow gate limit. The three MWh was successfully redelivered on 17 December 2015.

Detailed Operating Plans

During the period covered by this report, the CRTOC used the DOP for 1 August 2015 through 31 July 2016, dated June 2015, and the DOP for 1 August 2016 through 31 July 2017, dated June 2016, to guide Canadian storage operations. These DOPs established criteria for determining the Operating Rule Curves (ORCs), proportional draft points, as well as other operating criteria for use in actual operations. The 2015-2016 and 2016-2017 DOPs were based respectively on the 2015-2016 AOP and 2016-2017 AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects. The 2015-2016 and 2016-2017 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 Kinbasket. The 2015-2016 DOP and 2016-2017 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. In addition, the 2015-16 DOP and TSR for the same period incorporated an update to the Grand Coulee storage/elevation table.

The TSR studies were updated twice monthly throughout the reporting period for current inflow forecasts, flood risk management curves and variable refill curves (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 2016, were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Koocanusa for the 2015-2016 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 STLA and supplemental operating agreements.

Libby Coordination Agreement

During the period covered by this report, the LCA was supplemented by the Short-Term Libby Agreement on Coordination of Libby Project Operations (STLA). The LCA required delivery to the U.S. Entity of one (1) aMW, shaped flat, over the entire 2015-2016 Operating Year. The most recent Libby Operating Plan is dated 7 July 2016. The STLA, signed by the Entities in September 2013, was intended to address, until 31 August 2015, issues raised by the Canadian entity regarding VarQ operations at Libby. The STLA provided the Canadian Entity additional flexibility to draft and store at Arrow. In December 2015, the Entities extended the term of the STLA for one additional year allowing the agreement to remain in effect until 31 August 2017. During the term that the STLA is in effect, Section 10 and Attachment C of the LCA are suspended. Other portions of the LCA 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
17 December 2015	Extension of the Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2019-2020
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2020-2021
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2021-2022
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2022-2023
13 January 2016	Columbia River Treaty Agreement on the Assured Operating Plan and Determination of downstream Power Benefits For Operating Years 2023-2024
16 June 2016	Columbia River Treaty Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2016 through 31 July 2017

Columbia River Treaty Operating Committee Agreements

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

Date Signed	Description	Authority
17 July 2015	Columbia River Treaty Operating Committee Arrow Summer Storage Agreement For the Period 1 July 2015 through 30 September 2015	Detailed Operating Plan 1 August 2014 through 31 July 2015 and Detailed Operating Plan 1 August 2015 through 31 July 2016
13 November 2015	Columbia River Treaty Operating Committee Agreement on Operation of Canadian Storage for Nonpower Uses for 1 December 2015 through 31 July 2016	Detailed Operating Plan 1 August 2015 through 31 July 2016
21 July 2016	Columbia River Treaty Operating Committee Arrow Summer Storage Agreement For the Period 23 July 2016 through 31 August 2016	Detailed Operating Plan 1 August 2015 through 31 July 2016 and Detailed Operating Plan 1 August 2016 through 31 July 2017

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

- Agreement between BPA and B.C. Hydro that allowed storage, and subsequent release, of Non-Treaty Storage Agreement (NTSA) water using of Recallable accounts for the period the period 3 October 2015 through 25 March 2016, providing mutual power and nonpower benefits during the period.
- Agreement between BPA and B.C. Hydro to allow B.C. Hydro to utilize space in BPA's Active NTSA account beginning 24 October 2015. The purpose of the agreement was to provide additional operating flexibility to both parties.

Long Term Non-Treaty Storage Agreement

The Long Term NTSA, executed in April 2012, was utilized by BPA and B.C. Hydro for power purposes through fall and winter of 2015-16. 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

Very much like the previous spring, unusually warm temperatures triggered early runoff in the Columbia Basin during the 2015-2016 Water Year. However, the main difference was that in contrast to typical El Niño years when precipitation can sometimes lag in the Columbia Basin, the near record 2015-16 El Niño supported plentiful precipitation – almost on par with equally strong El Niño events in 1982-83 and 1997-98. While winter temperatures were again above average, they were not nearly as warm as 2014-15, and were still cool enough to allow near normal snowpacks to build across the Basin.

The jet stream pattern was already impacted by a strengthening El Niño as the new water year began. By December, 2015, oceanic heat content over the central and eastern equatorial Pacific approached record levels (Figure 1) with water temperatures up to 3.5°C (5.3°F) above average. Although final statistics were not available from the U.S. NOAA/National weather Service Climate Prediction Center as of this writing, the 2016-17 El Niño was at least the second strongest on record, and perhaps tied for strongest on record – going back to 1950.

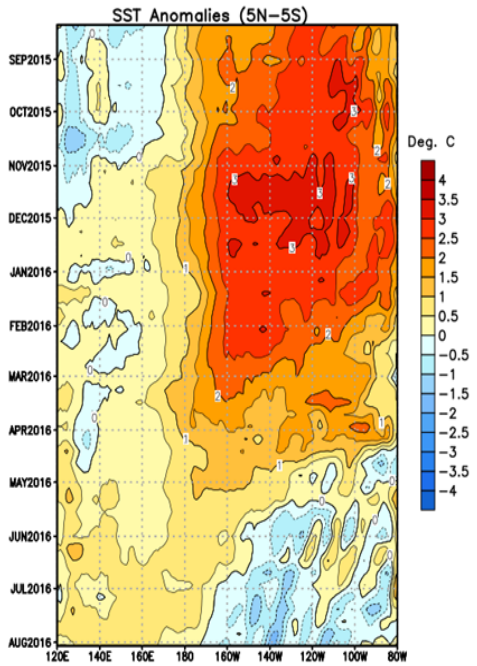


Figure 1: Water temperature anomalies along the equator from near Indonesia (left) to Peru (right). Image from U.S. NOAA Climate Prediction Center

Conventional rules-of-thumb indicate that, during El Niño winters, warmer and drier weather is more likely in the Columbia Basin. While this generally plays out during weak or moderate events, strong El Niño episodes can increase tropical moisture availability throughout the central Pacific and at unusually high latitudes. This can make it much easier for storm systems crossing the Pacific to tap into this moisture, and rapidly evolve into heavy precipitation atmospheric river events (or, as they are more commonly called, Pineapple Express events). This played out several times during the winter of 2015-16, particularly in December 2015, when basin average precipitation of 5.06 inches (128.5mm) fell on the basin – the 3rd wettest December on record going back to 1976, and just shy of the all-time record in December 1997. Above Grand Coulee, though, it was the wettest December on record, with 5.47 inches (138.9mm) of precipitation recorded. In contrast to the winter of 2014-15, which also featured several of these atmospheric river events, temperatures were a couple of degrees colder, snow levels were lower, and the entire Columbia Basin was impacted. Thus, while lower elevations did receive record-breaking rainfall and fairly serious low elevation flooding, much of the precipitation fell as snow east of the Cascades.

While not nearly as wet as it was during the fall, near or above average precipitation continued in the northern half of the Basin throughout the winter, while generally drier weather took hold over the Snake basin. So much snow fell in December, though, that by the end of March, most mid and upper elevation reporting stations had near or above average snowpack, even in the Snake Basin (Figure 2). As March drew to a close, basin average snowpacks were around 107% of average, with winter basin average precipitation above average and much improved over the fall and winter of 2014-15 (Figure 3).

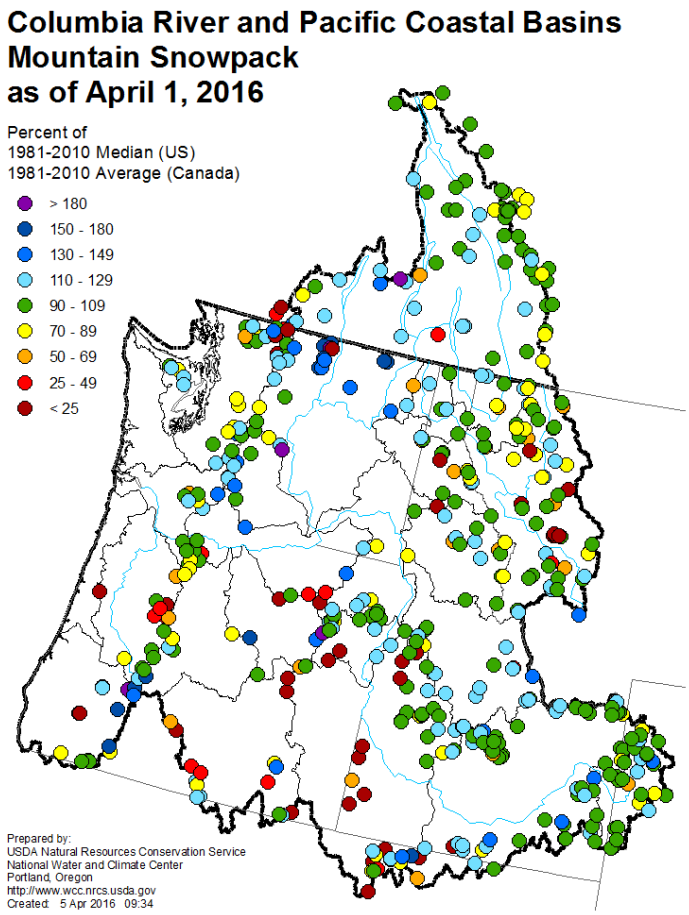


Figure 2: Columbia River and Pacific Coastal Basins Mountain Snowpack, relative to median/average.

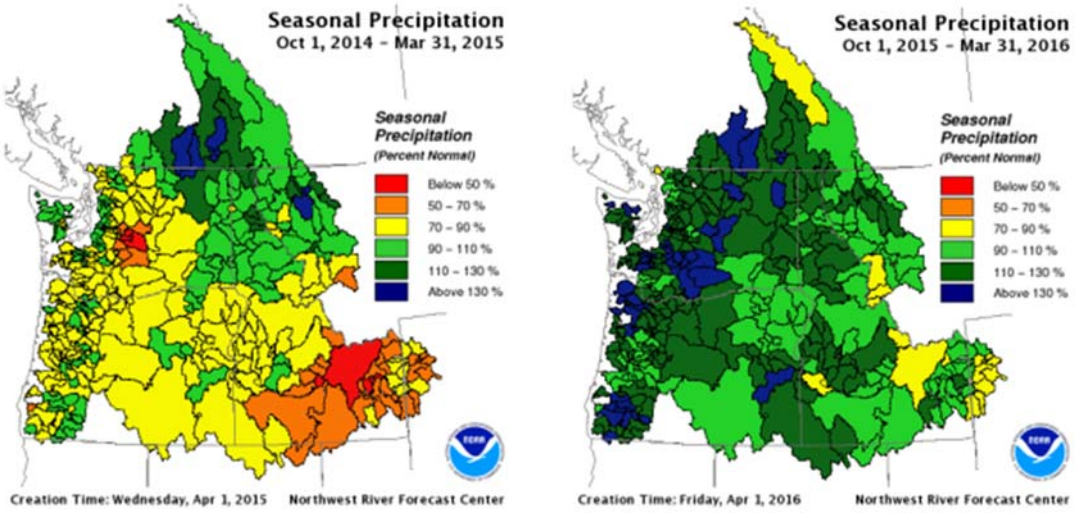


Figure 3: Basin average precipitation for October 2014-March 2015, and October 2015-March 2016. Images from NOAA/NWS Northwest River Forecast Center.

By April, though, a very similar situation that we saw in 2015 repeated itself in 2016 – with similar results. Temperatures warmed quickly and remained warm throughout April (Figure 4) all the way into early May. Predictably, snowpacks quickly ripened and melted. April flows rose sharply, with the spring snowmelt peaking about 35 days earlier than usual at The Dalles on 25 April. Fortunately, snowpacks were much deeper than in 2015, but after one last peak in early June, natural flows once again dropped sharply across June and well below average in July. While the June and July average flows were near the lowest 10th percentile, they remained well above the record low natural flows observed in 2015.

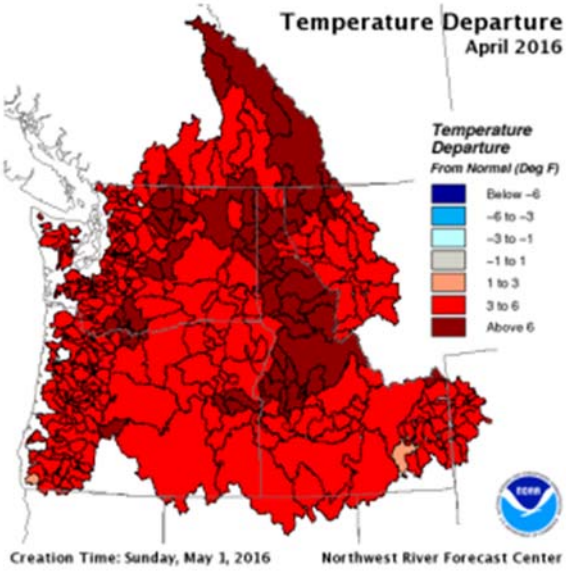


Figure 4: Basin average temperatures (in °F), April 2016. Image from NOAA/NWS Northwest River Forecast Center.

Fears of another hot, dry summer grew, especially after the first, unusually early heat wave in early June. The heat wave was particularly noticeable in British Columbia where several large, early season wildfires erupted. However, by mid-June, the El Niño ended as water temperatures rapidly cooled in the central and eastern Pacific, while they warmed in the West Pacific. This may have played a role in allowing the jet stream to shift unusually far south into British Columbia during July through September. This cooled temperatures across the basin, and helped support occasional rounds of thunderstorms across northern and eastern potions of the basin.

In the end, Water Year 2016 basin average temperatures were 1.8°F (1.0°C) above average – which was cooler than 2015, and close to basin average temperatures in 2013 and 2014. Basin average precipitation in the 2016 water year ranged from about 110% of average along and west of the Cascades, to about 90% of average in the Snake Basin (Figure 5).

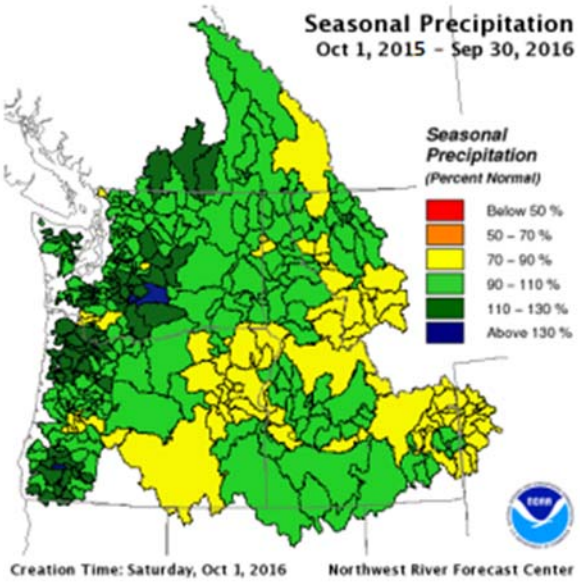


Figure 5: Columbia Basin Precipitation relative to 1981-2010 average. Image from NOAA/NWS Northwest River Forecast Center.

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 2015	+1.1/ +2.0	78%	56%	64%
September 2015	+0.0/ +0.0	108%	116%	101%
October 2015	+ 3.0 / + 5.4	81%	103%	93%
November 2015	-1.2 / - 2.2	103%	77%	88%
December 2015	+ 0.6 / + 1.1	126%	161%	151%
January 2016	+ 1.2 / +2.2	90%	91%	94%
February 2016	+ 2.8 / +5.2	116%	64%	89%
March 2016	+ 1.3 / + 2.3	132%	125%	131%
April 2016	+ 3.1 / + 5.6	56%	80%	63%
May 2016	+ 0.9 / + 1.6	111%	84%	93%
June 2016	+ 1.3 / + 2.3	67%	30%	53%
July 2016	- 0.4 / - 0.7	92%	60%	81%
August 2016	+ 0.3 / + 0.5	48%	12%	31%
September 2016	-0.7 / -1.3	103%	132%	103%
Water Year 2016	**+ 1.0 / + 1.8**	**97%**	**90%**	**95%**

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

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July through 30 September 2016 are shown on Charts 5 through 7. Libby hydrographs are shown in Chart 8. Observed flows and unregulated flows (computed using the USACE Hydrologic Engineering Center's Reservoir System Simulation (HEC-ResSim or ResSim) model with SSARR[2] routing 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

[2] SSARR stands for Streamflow Synthesis and Reservoir Regulation and is a computer simulation model.

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 13,204.1 cubic meters per second (m^3/s) (466.3 kcfs [thousands of cubic feet per second]) on 10 May 2016, based on the USACE ResSim 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 ResSim model does. Natural lake effects cause attenuation and dampening of flows; thus, the ResSim model simulations provide lower flows than the NWRFC tabulations. As per the table below, the average unregulated August 2015-July 2016 streamflow at The Dalles was slightly below average with a runoff volume of 152.4 km^3 (123.5 Maf) (95 percent of 1981-2010 average) for the same period. This is approximately 7 percent higher than last year's annual runoff.

Columbia River Unregulated Streamflow

Time Period	Columbia River at Grand Coulee			Columbia River at The Dalles		
	Unregulated Flow		Percent of Normal	Unregulated Flow		Percent of Normal
	kcfs	m^3/s		kcfs	m^3/s	
Aug-15	67.1	1,900	72	84.6	2,396	68
Sep-15	67.6	1,914	120	88.1	2,495	101
Oct-15	43.6	1,235	96	70.6	1,999	85
Nov-15	43.2	1,223	89	85.1	2,410	90
Dec-15	49.4	1,399	124	99.1	2,806	109
Jan-16	38.9	1,102	97	87.1	2,466	89
Feb-16	58.2	1,648	138	136.1	3,854	123
Mar-16	87.6	2,481	146	192.1	5,440	130
Apr-16	210.0	5,947	175	363.6	10,296	157
May-16	253.0	7,164	100	403.2	11,417	98
Jun-16	199.2	5,641	68	278.0	7,872	63
Jul-16	122.4	3,466	69	156.7	4,437	66
Aug-16	71.7	2,030	77	93.0	2,633	74
Sep-16	47.3	1,339	84	67.8	1,9210	78
Aug-Jul Average	**103.4**	**2,927**	**98**	**170.4**	**4,825**	**95**

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

Seasonal Runoff Forecasts and Volumes

Seasonal runoff volumes for the April-August 2016 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	Percentage of 1981-2010 Average
Libby Reservoir Inflow	6.7	5.4	92%
Duncan Reservoir Inflow	2.4	2.0	97%
Mica Reservoir Inflow	13.2	10.7	98%
Arrow Reservoir Inflow	26.5	21.4	98%
Columbia River at Birchbank	46.8	37.9	97%
Grand Coulee Reservoir Inflow	64.0	51.9	91%
Snake River at Lower Granite	21.5	17.4	83%
Columbia River at The Dalles	96.7	78.4	90%

Source: NWRFC runoff processor

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2016 for a large number of locations in the Columbia River Basin and updated at the beginning of each month from December to June as the season advanced. Table 1 and Table 1M list the April through August inflow volume forecasts for Mica, Keenleyside, 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, Keenleyside, 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 was prepared by the U.S. Army Corps of Engineers. The April 2016 forecast of January through July runoff for the Columbia River above The Dalles was 129.1 km^3 (104.6 Maf) and the actual observed runoff was 120.4 km^3 (97.6 Maf).

The following tabulations summarize the monthly forecasts since 1985 of the January-July runoff for the Columbia River above The Dalles compared with the actual runoff. The average January-July runoff volume for the period of 1981-2010 is 125.1 km^3 (101.4 Maf).

Historic Seasonal Runoff Forecasts and Volumes (km^3)

The Dalles, OR Volume Runoff Forecasts in km^3 (Jan-Jul)							
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Actual**
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
2015	126.6	128.0	113.1	118.3	106.7	106.1	103.2
2016	116.1	117.4	126.9	129.1	137.9	123.4	120.4
Minimum	97.7	81.9	72.3	69.2	69.7	68.5	71.8
Median	121.4	120.2	118.2	120.3	120.6	121.0	120.5
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
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
2015	102.6	103.8	91.7	95.9	86.5	86.0	83.7
2016	94.1	95.2	102.9	104.6	111.8	100.0	97.6
Minimum	79.2	66.4	58.6	56.1	56.5	55.5	58.2
Median	98.4	97.4	95.8	97.5	97.8	98.1	97.7
Maximum	138.0	145.0	142.0	149.0	153.0	159.0	159.0

V - RESERVOIR OPERATION

General

The 2015-16 Operating Year began with Canadian storage at 76.8 percent full. The Lake Koocanusa level was about 4.82 m (15.8 ft) below full, elevation 744.69 m (2443.2 ft), at the start of the operating year (1 August 2015) and the project was releasing water to meet NOAA Fisheries' 2010 and 2014 Supplemental Biological Opinion (BiOp) objectives for flow augmentation for listed salmon species in the U.S.

The water supply during the 2015-16 Operating Year was slightly below average, referencing the 1981-2010 period of record. The actual runoff for the overall Columbia Basin (U.S. and Canada combined) measured at The Dalles, OR, for January through July 2016 was 96 percent of average. However, the actual runoff for the period April – August was only 90 percent of average, indicating stronger precipitation and runoff early in the season and a drying trend late spring into summer.

For the period 1 August 2015 through 30 September 2016, the CRTOC executed three operating agreements. The first agreement was the Arrow Summer Storage agreement effective for the period 1 July 2015 through 30 September 2015, impacting Keenleyside operations. The second was the Nonpower Uses Agreement (NPU), for the 2015-16 Operating Year (see Section III Operating Arrangements) that impacted Mica and Keenleyside operations. The third agreement was the Arrow Summer Storage agreement effective for the period 23 July 2016 through 15 August 2016, impacting Keenleyside operations.

Canadian Storage Operation

At the beginning of the 2015-16 Operating Year (1 August 2015), actual Canadian storage provided under Article II of the CRT (Canadian storage) was at 9.6 km^3 (11.9 Maf) or 76.8 percent full. Canadian Treaty storage drafted to a minimum of 2.1 km^3 (2.6 Maf), or 16.6 percent full in 4 March 2016. Canadian composite storage refilled to 10.2 km^3 (12.6 Maf), or 81.2 percent full, at the end of the operating year, 31 July 2016.

The Canadian Treaty composite storage operation was consistent with the DOP TSR for the 2015-16 operating year, as modified by Entity or Supplemental Operating Agreements such as the STLA, Nonpower Uses Agreement and Arrow Summer Shaping Agreement. During August 2015 through January 2016 and again during June 2016 through the end of this reporting period, 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 project target storage operation are accumulated in respective Flex accounts.

An overrun in a Flex 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, Keenleyside, 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 operations below.

Mica

At the start of the operating year on 1 August 2015, Kinbasket level was 750.27 m (2461.5 ft). This was 4.18 m (13.7 ft) below the normal full pool elevation. Similar to last year, 2015/2016 fall and winter was warmer than normal. Despite relatively low loads, generation from Mica from September 2015 to January 2016 was 110% of normal for power generation and to support Arrow reservoir levels during periods of deep proportional draft resulting from the 2015 drought conditions. The reservoir reached a minimum level of 729.39 m (2393.0 ft) on 1 April 2016, about 7.62 m (25.0 ft) lower than the 2015 minimum level.

During the spring and summer, Mica was operated as required for power generation and to support Arrow levels. At the end of the operating year (31 July 2016), the Kinbasket level was 751.58 m (2465.8 ft). The reservoir continued to fill through August and September to

reach a maximum level of 752.03 m (2467.3 ft) on 4 September 2016, 2.35m (7.7 ft) below normal full pool.

Inflow into Kinbasket was 107 percent of average over the period August to December 2015. Over this same period, the Mica outflow varied from a monthly average high of about 1214.8 m^3/s (42.9 kcfs) in August 2015 to a monthly average low of about 407.8 m^3/s (14.4 kcfs) in October 2015. Inflows into Kinbasket were about 100 percent of normal over the period January to July 2016. The Mica discharge over this same period varied from a monthly average high of 1,127.0 m^3/s (39.8 kcfs) in January to a monthly average low of 68.0 m^3/s (2.4 kcfs) in May.

Mica had a Treaty overrun of 0.3 km^3 (118.3 ksfd) on 31 July 2015. The maximum underrun for the operating period was 1.7 km^3 (690.5 ksfd) on 29 July 2016, and the maximum overrun was 1.2 km^3 (470.1 ksfd) on 18 September 2015.

For the reporting period, NTSA water was released and stored by both parties into their respective accounts. In 2015, BPA and B.C. Hydro developed two NT agreements in October to enable additional storage to reduce draft from Arrow reservoir for the benefit of reservoir users for Canada and to improve certainty of 1 Maf of Flow Augmentation (FA) storage for U.S. fisheries. Under these agreements, B.C. Hydro and BPA agreed to open the Recallable accounts and allow B.C. Hydro to overfill its Active account. As such, B.C. Hydro and BPA refilled their Recallable accounts from 3 through 23 October 2015. Storage under this account was returned from 26 December 2015 through 15 January 2016.

Further, B.C. Hydro overfilled its Active account from 24 October through 13 November 2015. The overfilled portion of BCH NT Active account 0.3 km^3 (126 ksfd) was fully released from 5 December 2015 through 1 January 2016. These releases were concurrently stored into U.S. FA account resulting in no physical changes in Arrow releases. By the end of March 2016, both B.C. Hydro and BPA's NT accounts were refilled to 90% and 85% full.

Revelstoke

During the 2015-16 Operating Year, the Revelstoke project was operated primarily as a run-of-river plant, with the reservoir level maintained generally within 1.52 m (5.0 ft) of its normal full pool elevation of 573.02 m (1880.0 ft). During the winter, on occasion, the reservoir operated below its normal low level to provide additional short-term generation,

reaching its lowest elevation of 571.06 m (1873.5ft), or 1.95 m (6.4 ft) below full pool, on 29 April 2016.

Keenleyside

Arrow reached a maximum level of 435.47 m (1428.7 ft), or 4.66 m (15.3 ft) below full pool, on 13 June 2015. The reservoir drafted from August through January 2016, reaching its lowest level for the 2015-16 operating year, 424.13 m (1391.5 ft), on 31 January 2016 – this was 0.30 m (1 foot) higher than the previous year's minimum level on 30 March 2015.

After reaching its minimum level in January 2016, the reservoir refilled from well below normal to above normal from March through June due to a combination of relatively low winter Treaty outflows, high inflows from snowmelt runoff and increased generation from the Upper Columbia projects.

The 2016 freshet, however, was very brief as the runoff peaked in April for many parts of the Columbia basin and steadily declined through the rest of the season. As such, the Columbia reservoir system in the TSR study was in proportional draft beginning in June, continuing through the reporting period of September 2016. This operation resulted in high discharges from Keenleyside across the spring/summer and produced correspondingly low summer Arrow reservoir levels. The reservoir filled to a maximum level of 437.24 m (1434.5 ft), or 2.90 m (9.5 ft) below full pool, on 10 June 2016.

With persistent low flow conditions in the Columbia basin and increasing proportional draft requirements going into the summer, Arrow drafted quickly from June into September, reaching 430.96 m and 427.88 m (1413.9 ft and 1403.8 ft) by 31 August and 30 September 2016, respectively.

Local inflow into Arrow was 99 percent of average over the period August-December 2015. The Keenleyside discharge varied from a monthly average high of 2160.6 m^3/s (76.3 kcfs) in August to a monthly average low of 790.0 m^3/s (27.9 kcfs) in December. Local inflow into Arrow was 103 percent of normal over the period January-July 2016. Outflow over this same period varied from a monthly average low of 286.0 m^3/s (10.1 kcfs) in March to a monthly average high of 2016.2 m^3/s (71.2 kcfs) in July.

The CRTOC negotiated a Nonpower Uses Agreement for 2015-16 in order to manage Canadian and U.S. fisheries needs. In December 2015 and January 2016, Arrow Treaty flows were reduced to enable 1.2 km^3 (504 ksfd, 1 Maf) of Flow Augmentation storage as specified under the NPU. Under the provisions of the Water Use Plan (WUP) monitoring requirements, there were no provisions for whitefish protection flows in 2016. Additional provisions under the NPU maintained Keenleyside discharges during April-June 2016 at or above 424.8 m^3/s (15 kcfs) to protect rainbow trout spawning downstream of Keenleyside Dam. All of the water stored for Flow Augmentation under the NPU was released, for U.S. salmon migration, in July 2016.

Due to an increasing proportional draft point in each TSR, the CRTOC negotiated an Arrow Summer Storage Agreement to keep actual flows below 2,123.8 m^3/s (75 kcfs) in July to help mitigate local concerns and operational issues. The agreement shaped water from July into August under the authority of DOP16 and DOP17. The composite treaty storage operated to the 15 August 2016 TSR target storage.

Under terms of the Short Term Libby Agreement (STLA), B.C. Hydro exercised 0.1 km^3 (49 ksfd) of provisional storage into Keenleyside in October 2015. In December through the first half of February 2016, B.C. Hydro exercised 0.5 km^3 (196 ksfd) of STLA provisional draft followed by a storage of 0.5 km^3 (196 ksfd) in the second half of February and March 2016. By 18 March 2016, the account balance was brought to zero. There has been no activity since until 13 through 26 August 2016 when B.C. Hydro continuously released for a total of 0.2 km^3 (84 ksfd) under STLA.

Duncan

Operation of Duncan during the 2015-16 Operating Year (refer to Chart 7) followed all Treaty requirements and implemented the operational constraints agreed upon in the Duncan WUP and ordered in the Water License Order (issued on 21 December 2007) except when variance were requested and granted.

Duncan Reservoir peaked at 575.01 m (1886.6 ft), 1.65 m (5.4) ft below full, on 3 August 2015. Duncan Dam discharges were increased to 184.1 m^3/s (6.5 kcfs) through August and 155.7 m^3/s (5.5 kcfs) into September to meet proportional draft requirements under the Columbia River Treaty. To enable this operation, B.C. Hydro requested and was granted a

variance from the Water Comptroller for Duncan Reservoir to deviate from the summer recreation target of 575.46 m (1888.0 ft) between August 10 and Labour Day per the Duncan Water Use Plan Order.

Starting 2 September 2015, Duncan discharges were increased to maintain flows in the Duncan River below the Lardeau River confluence (DRL) gauging station at 249.2 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. Discharges were reduced on 25 September 2015 to target kokanee spawning flows of 73.6 m^3/s (2.6 kcfs) at DRL and held this discharge until 22 October 2015. After the kokanee spawning flow period, Duncan Dam increased discharge to target 240.7 m^3/s (8.5 kcfs) at DRL to support Arrow Lake levels during proportional draft operations as part of the Columbia River Treaty. To enable this operation, B.C. Hydro requested and was granted a variance from the Water Comptroller to deviate from the maximum DRL flow of 110.4 m^3/s (3.9 kcfs) from 22 October to 21 December 2015 per the Duncan Water Use Plan Order.

On 22 December and 29 December, Duncan discharges were reduced from 203.9 m^3/s to 141.6 m^3/s (7.2 kcfs to 5 kcfs) and from 141.6 m^3/s to 79.3 m^3/s (5 kcfs to 2.8 kcfs), respectively. Duncan discharges were further reduced in January and February 2016 in order to draft the reservoir to meet the end-of-month Treaty flood risk management targets of 560.77 m (1839.8 ft) by 31 January 2016 and 552.85 m (1813.8 ft) by 29 February 2016.

Duncan was drafted to a minimum level of 547.21 m (1795.3 ft) on 8 April 2016. The reservoir reached a similar minimum level of 546.90 m (1794.3 ft) on 21 April 2015. The project was operated to provide minimum flow of 73.6 m^3/s (2.6 kcfs) at DRL as required for fish until late May, and the Duncan discharge was adjusted to ensure DRL flow reductions did not exceed 48.1 m^3/s (1.7 kcfs) as per Water License requirements.

The reservoir discharge was reduced to a minimum of 2.8 m^3/s (0.1 kcfs) on 20 May 2016 to begin reservoir refill and manage the level of Kootenay Lake. Releases from Duncan were held at minimum until late-July to refill the reservoir. In 2016, Duncan refilled to a maximum of 576.47 m (1891.3 ft), 0.21 m (0.7 ft) below full, on 8 August 2016. Duncan discharges were gradually increased across August to target the summer recreation level of 575.46 m (1888 ft) between 10 August 2016 and Labour Day. Beginning on 25 September,

discharges were ramped down to prepare for the fish spawning flow of 73.6 m^3/s (2.6 kcfs) during the period 1 - 21 October 2016.

Libby

The operation of Libby and Koocanusa is shown in Chart 8 of this document. Lake Koocanusa ended July 2015 at elevation 744.69 m (2443.2 ft). The project was drafted to elevation 743.93 m (2440.7 ft) at the end of August 2015, with outflows held constant at 198.2 m^3/s (7.0 kcfs), the bull trout minimum, through the end of August 2015. The Kootenai Tribe of Idaho (KTOI) requested low flows in the fall of 2015 to assist with the continuing habitat restoration work in the Kootenai River, as had been the case in previous years. For the month of September, releases were maintained at 169.9 m^3/s (6.0 kcfs), which also is the September bull trout minimum, and the project ended the month of September at elevation 743.77 m (2440.2 ft). The final April – August 2015 inflow volume to the project was 5.3 km^3 (4.3 Maf), or 73 percent of normal (1981 – 2010, 30 year normal).

Releases were reduced to 113.3 m^3/s (4.0 kcfs), the default minimum flow, for the month of October, and the project ended the month at elevation 743.93 m (2440.7 ft). Outflow was increased in November to target end of year Flood Risk Management (FRM) goals. The December 2015 water supply forecast for April-August 2016 runoff was initially set at 7.2 km^3 (5.8 Maf), or 98 percent of average, requiring the end of December FRM elevation to be 736.18 m (2415.3 ft). An error in the input data for the water supply forecast equations was later discovered and the December forecast was revised to 7.3 km^3 (5.9 Maf). The December FRM elevation was reached at the end of the month (actual end of month was 736.09 m, 2415.0 ft) and releases were set to the 113.3 m^3/s (4.0 kcfs) through 19 January and then increased in order to meet end of January FRM elevation. Outflow for November – December averaged 371.0 m^3/s (13.1 kcfs).

Libby's seasonal volume forecasts increased over the drawdown season until the month of May and Libby Dam was drafted to 730.79 m (2397.6 ft) at the end of March, requiring outflows above the minimum flow for the second half of January and for most of March. A deviation request was submitted by the USACE Seattle office to be about three feet above the required 733.65 m (2407.0 ft) end-of-February FRM elevation. The deviation request was approved by the USACE Division office. The benefit of the deviation was for system

operational flexibility. The respective end of January and end of February 2016 reservoir elevations reached were 734.90 m (2411.1 ft) and 734.60 m (2410.1 ft). Average outflow for the months of January, February and March was respectively 152.9 m^3/s (5.4 kcfs), 116.1 m^3/s (4.1 kcfs) and 331.3 m^3/s (11.7 kcfs). At the end of March, there was little to no low elevation snowpack in the basin, and with April projected to have temperatures well above average, Libby Dam was operated to meet the Flood Control Refill Curve in the middle of the month, which initiated refill of the reservoir. On 19 April, Libby Dam reached its minimum elevation for the year of 730.70 m (2397.3 ft) and ended the month of April at 733.50 m (2406.5 ft). On 20 April, it was determined that the Initial Control Flow (ICF) was expected to be crossed on the 22nd of the month and Libby's releases were set at the VarQ flood risk management outflow of 467.2 m^3/s (16.5 kcfs).

The water supply forecast for May 2016 was 7.3 km^3 (5.8 Maf), or 99 percent of average. Libby outflow was set at an adjusted VarQ outflow of 438.9 m^3/s (15.5 kcfs). On 13 May 2016, Libby began to release the sturgeon volume, 1.2 km^3 (0.95 Maf) set by the May water supply forecast, with releases increased to 566.3 m^3/s (20.0 kcfs) for 2 days, followed by powerhouse capacity of 750.4 m^3/s (26.5 kcfs) for 11 days. In 2016, this was a single pulse operation for a longer than previously used peak (11 days instead of 7 days) in dry years and was followed by a gradual ramp-down. Releases were ramped down to 198.2 m^3/s (7.0 kcfs) on 14 June once the sturgeon volume was expended. The elevation at Libby ended the month of June at 743.50 m (2439.3 ft).

The operation for the rest of the summer, July through August, was to try to refill Libby as best as possible and still meet the 746.46 m (2449.0 ft) target by the end of September, as required in the NOAA BiOp and coordinated through the Technical Management Team (TMT), with The Dalles water supply forecast being above the 20th percentile (below the 20th percentile the requirement would be to draft to 743.41 m, or 2439.0 ft). Libby reached its peak elevation for the summer on 18 August, 746.03 m (2447.6 ft), which was 3.47 m (11.4 ft) below full pool. Due to low inflow conditions, the project kept releases to the minimum bull trout flow of 198.2 m^3/s (7.0 kcfs) and then ramped down to 169.9 m^3/s (6.0 kcfs), the minimum bull trout flow for September. Libby elevations were 745.72 m (2446.6 ft) and 745.3 m (2445.2 ft) at the end of August and September, respectively. The 169.9 m^3/s

(6.0 kcfs) outflow in September was also the requested release from Libby to help with the in-stream habitat work for the Kootenai Tribe of Idaho.

Kootenay Lake

Kootenay Lake is operated (refer to Chart 9) to meet numerous interests, including provision of meeting maximum levels under the IJC and minimum flow targets in the Kootenay River at the Brilliant Dam. Operations target a minimum Brilliant flow of 509.7 m^3/s (18.0 kcfs) during the period December through September and 453.1 m^3/s (16 kcfs) during October through November.

On 7 July 2015, Kootenay Lake (at Nelson) was drafted to 531.36 m (1743.32 ft), at which point the IJC compliance gauge switched from Queens Bay to Nelson, and the lake was maintained near 531.27 m (1743.0 ft) through August. Starting in late August 2015, Kootenay Lake began drafting to target 530.96 m (1742 ft) by 15 September 2015 for the Kokanee shoal spawning operation. Once the target level was reached, inflows were passed to maintain the lake level at 530.96 m ± 0.05m (1742.0 ± 0.15 ft) until 15 October. Thereafter, Kootenay Lake continued to pass inflows in order to maintain lake levels. This resulted in Brilliant discharges falling below the minimum target flow of 453.07 m^3/s 16 kcfs in October.

In November and December 2015, discharges recovered to above minimum flows due to above normal precipitation and basin inflows. Kootenay Lake refilled during this period ending December about 0.38 m (1.25 ft) below IJC. From 3 through 19 January 2016, the lake was drafted to provide about 0.46 m (1.5 ft) below the IJC to accommodate a Brilliant Expansion plant outage. Kootenay Lake continued to draft since as the IJC maximum level begins to lower linearly towards 531.57 m (1744 ft) by 1 February and 531.08 m (1742.4) ft by 1 March.

High inflows in March and April caused Kootenay Lake to exceed the IJC maximum level, although discharges were proactively brought to maximum flow rates through Grohman Narrows since early March. Kootenay Lake drafted to its lowest 2016 level of 530.41 m (1740.2 ft) on 7 March 2016. Despite maximum outflows from the lake, the Kootenay Lake level remained above the IJC Order reference level from about mid-March 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 8 April 2016. Following this declaration, the Corra Linn and Kootenay Canal projects continued to pass maximum discharge (free flow), limited only by the natural flow restriction of Grohman Narrows, until early June 2016. The level of Kootenay Lake level continued to increase during the April-May period, peaking at 532.82 m (1748.1 ft) on 27 May 2016. By comparison, in 2015, the peak level was 532.53 m (1747.1 ft) on 9 June 2016. Discharge from Kootenay Lake peaked at 1,713.2 m^3/s (60.5 kcfs) while the Kootenay River discharge at Brilliant peaked at 2,016.2 m^3/s (71.2 kcfs) on 28 May 2016.

On 2 July 2016, Kootenay lake was drafted to 531.36 m (1743.32 ft), at which point the IJC compliance gauge switched from Queens Bay to Nelson, and the lake was maintained near 531.27 m (1743.0 ft) through August.

VI - FLOOD RISK MANAGEMENT AND POWER ACCOMPLISHMENTS

General

During the period covered by this report, the Duncan, Arrow, and Kinbasket 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 2015-2016 DOP was 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/Keenleyside project operating criteria, and non-power 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, Keenleyside, 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.

The Libby December 2015 water supply forecast for April-August 2016 runoff was 7.1 km^3 (5.8 Maf), or 98 percent of average (based on the 1981-2010 inflow). Based on this forecast, the recommended draft for Koocanusa was 2.2 km^3 (1.8 Maf), to elevation 736.18 m (2415.3 ft) on 31 December. Libby was operated to its VarQ flood risk management storage reservation diagram. Both Libby and Duncan dams began refill in mid-April according to the ICF date.

Flood Risk Management

Overall, the 2016 water supply for the Columbia Basin was slightly below average. The Snake River Basin's unregulated runoff was 83 percent of average. However, the unregulated runoff in all of the other Columbia River Basin sub-basins were within 90 to 100 percent of average. All combined, the unregulated April-August volume at The Dalles of 96.7 km^3 (78.4 Maf) was 90 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, Keenleyside, and Duncan were operated according to the flood risk management requirements of the May 2003 FCOP. Libby was operated to its VarQ Storage Reservation Diagram and accompanying rules. The unregulated peak flow (based on the USACE ResSim program output) at The Dalles, Oregon, shown on Chart 13, was estimated at 13,204.1 m^3/s (466.3 kcfs) on 10 May 2016, and a regulated daily peak flow for April through July of 9,389.9 m^3/s (331.6 kcfs) occurred on 25 April 2016 as measured at The Dalles Dam. The regulated peak stage[3] at Vancouver, Washington, (VAPW) was observed at 3.27 m (10.74 ft) on 25 April 2016 while the flood stage is 4.88 m (16.0 ft). The peak unregulated stage at Vancouver was estimated at 5.00 m (16.4 ft) on 11 May 2016.

For the 2015-2016 Operating Year, the Canadian Entity elected to operate Mica and Keenleyside 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 Kinbasket, 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 2016, 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	302.8	8,576
February Forecast	304.9	8,635
March Forecast	319.8	9,054
April Forecast	321.0	9,090

[3] The peak observed regulated stage at the Vancouver gage (VAPW) during the reporting period was 3.74 m (12.26 ft) which occurred on 10 December 2015 (during winter and outside freshet period).

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 2016, the ICF date was declared as 22 April based on a projection that the unregulated flow would consistently remain above the ICF. 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 9,389.9 m^3/s (331.6 kcfs) occurring on 25 April 2016. 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. The Grand Coulee pool was drawn down for drum gate maintenance this year, so the chart is less informative for showing the synthetic reservoir balancing between Keenleyside and Grand Coulee. The chart provides more information to the reader in large water years when Keenleyside is drafted for FRM in response to Grand Coulee's FRM draft requirements as a synthetic reservoir. As shown in the chart, starting 22 April 2016, Arrow filled faster relative to Grand Coulee compared to the guideline. Keenleyside 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 2015 through 30 September 2016, 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 2015 through 31 July 2016, the Canadian Entitlement amount, before deducting transmission losses, was 488.7 aMW of energy, scheduled at rates up to 1332 MW capacity. From 1 August 2016 through 30 September 2016, the amount, before

deducting transmission losses, was 484.0 aMW of energy, scheduled at rates up to 1333 MW capacity. The Canadian Entitlement obligation was determined by the 2015-2016 and 2016-2017 AOP/DDPBs.

During the course of the 2015-2016 Operating Year, there was one CE delivery curtailment event. On 15 December 2015, there was a three MWh cut in one hour which was not due to the intertie system operating limit but due to a flow gate limit. The three MWh was successfully redelivered on 17 December 2015. The following Figure 5 shows the historic Canadian Entitlement amounts from the DDPB studies as compared to the estimated amount under the 1964 Canadian Entitlement Exchange Agreement (CEEA).

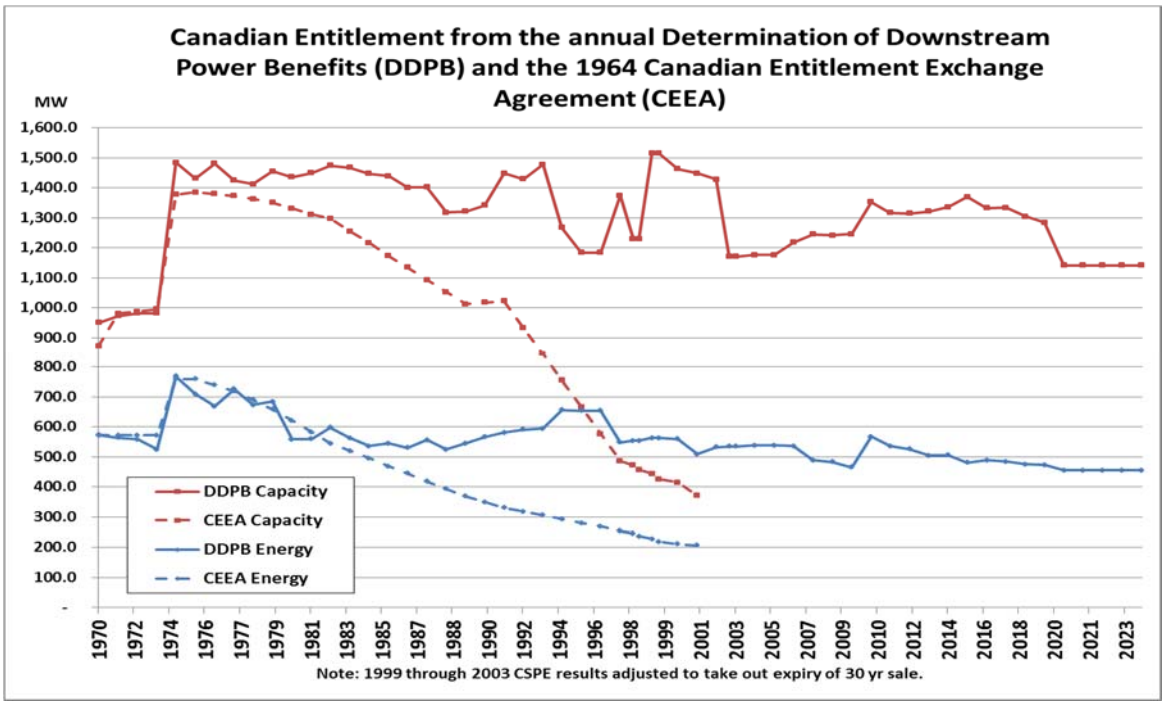


Figure 5: Canadian Entitlements: Agreed CEEA Amounts vs. DDPB Amounts

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 percent), 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).

2024 Review

Led 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 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.

On 13 December 2013 the U.S. Entity transmitted a document called "The U.S. Entity Regional Recommendation for the Future of the Columbia River Treaty after 2024," to the U.S. Department of State. The U.S. Entity's Recommendation and the three-year process leading up to it marked the successful conclusion of the regional engagement chapter of the U.S. Entity's Treaty Review effort, and the beginning of the formal review by the U.S. Government. In the fall of 2015 the U.S. Department of State assigned a lead negotiator to the Columbia River Treaty, a key step in advancing the U.S. process towards formal negotiations. While awaiting the completion of the formal authorization for the U.S. to enter

into negotiations with Canada, the lead negotiator conducted informal discussions with regional states, sovereigns, stakeholders, and federal agencies for further alignment and understanding of issues.

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 of Canadian storage on downstream U.S. power generation during the 2015-16 Operating Year, based on the Pacific Northwest Coordination Agreement (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 110 aMW. In addition to the increase in average annual U.S. power generation, the Treaty regulation also shifted the timing of generation from the May/June period into the fall and winter months. No quantification of this benefit is provided in this report.

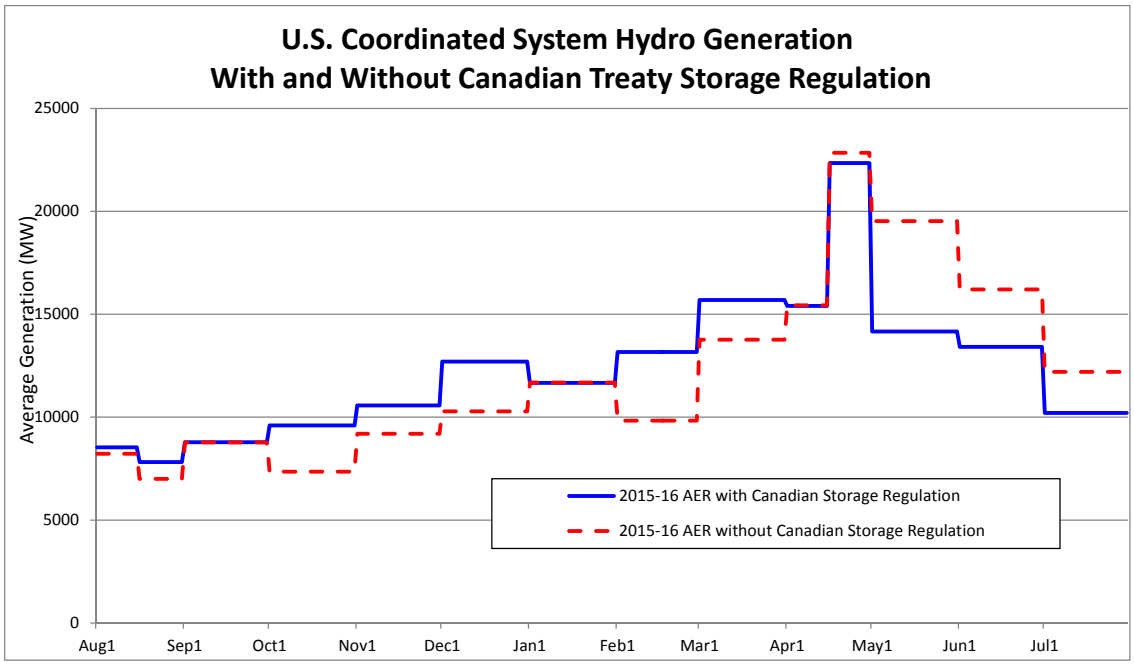


Figure 6: U.S. Coordinated System Hydro Generation

Treaty operating plans are designed to adapt to streamflow and water supply conditions that arise and evolve over the Operating Year. Operating Plans are implemented through the TSR model study which incorporates streamflows, water supply forecasts and operating parameters dependent on runoff conditions during the Operating Year, which resets the specified Canadian storage target twice a month and finalizes the target in the first TSR of the subsequent period. This report discusses conditions as realized for the 2015-16 Operating Year and describes the response of Canadian storage to the actual inflows and water supply conditions which occurred over the year. The risk mitigation benefits associated with the Treaty's flexibility to adapt to the broad array of water conditions that were possible going into the water year are not addressed or quantified in this report.

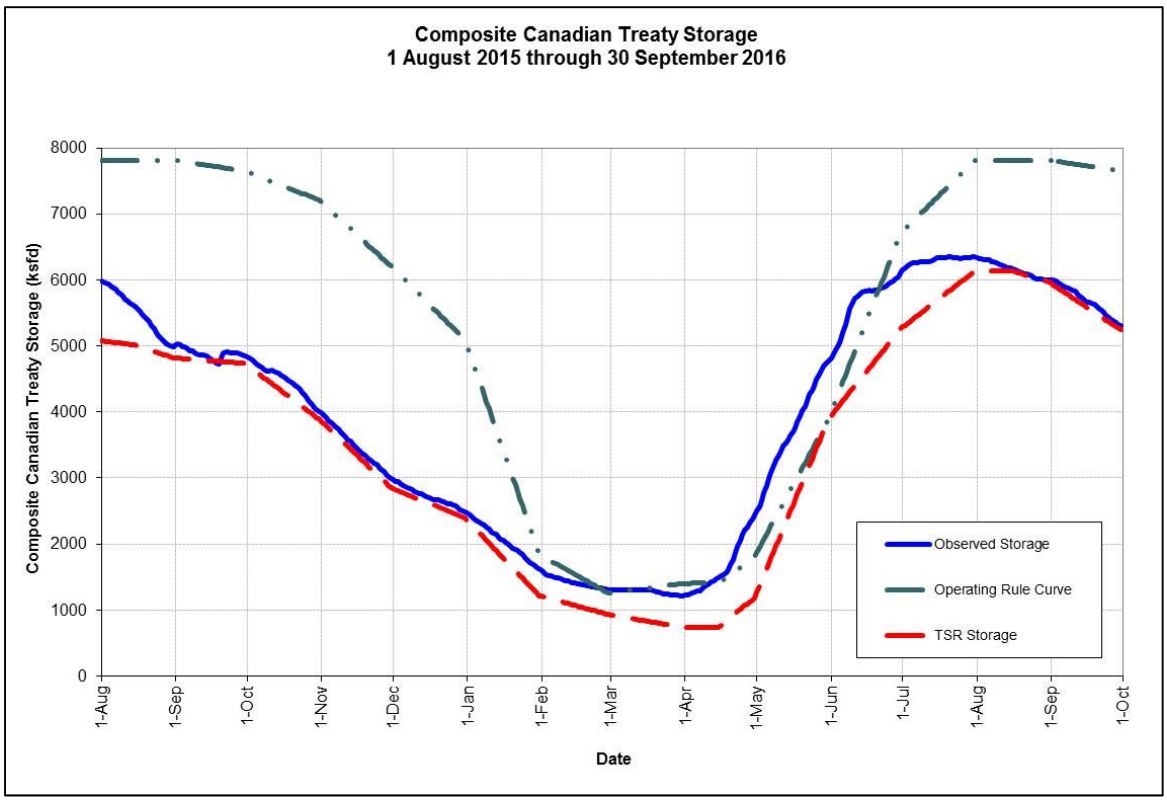


Figure 7: Composite Canadian Treaty Storage

Figure 7 compares the actual operation of the composite Canadian storage to the results of the DOP TSR study. Canadian Treaty reservoirs operated in proportional draft mode during August 2015 through January 2016 and again during June 2016 through the end of this reporting period to meet Treaty firm loads. The STLA Provisional Account was drafted and filled as described in Section V between October 2015 and March 2016. In March, the account filled

to the original initial balance and remained there through the end of the Operating Year. Under the 2015-2016 NPU agreement, the U.S. stored 1.2 km^3 (504 ksfd, 1 Maf) above the TSR for Flow Augmentation in December and January and maintained that balance until it was released by the end of July. Also under the NPU agreement, Treaty discharges from Keenleyside were set low during April through June to support trout spawning which contributed to Treaty Storage being above the TSR during that timeframe. In July, the CRTOC agreed to an Arrow Summer Shaping Agreement to help manage increasing flows from Keenleyside due to the increasing proportional draft point. At the end of July, Treaty Storage was above the TSR due to the Arrow Summer Shaping Agreement.

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

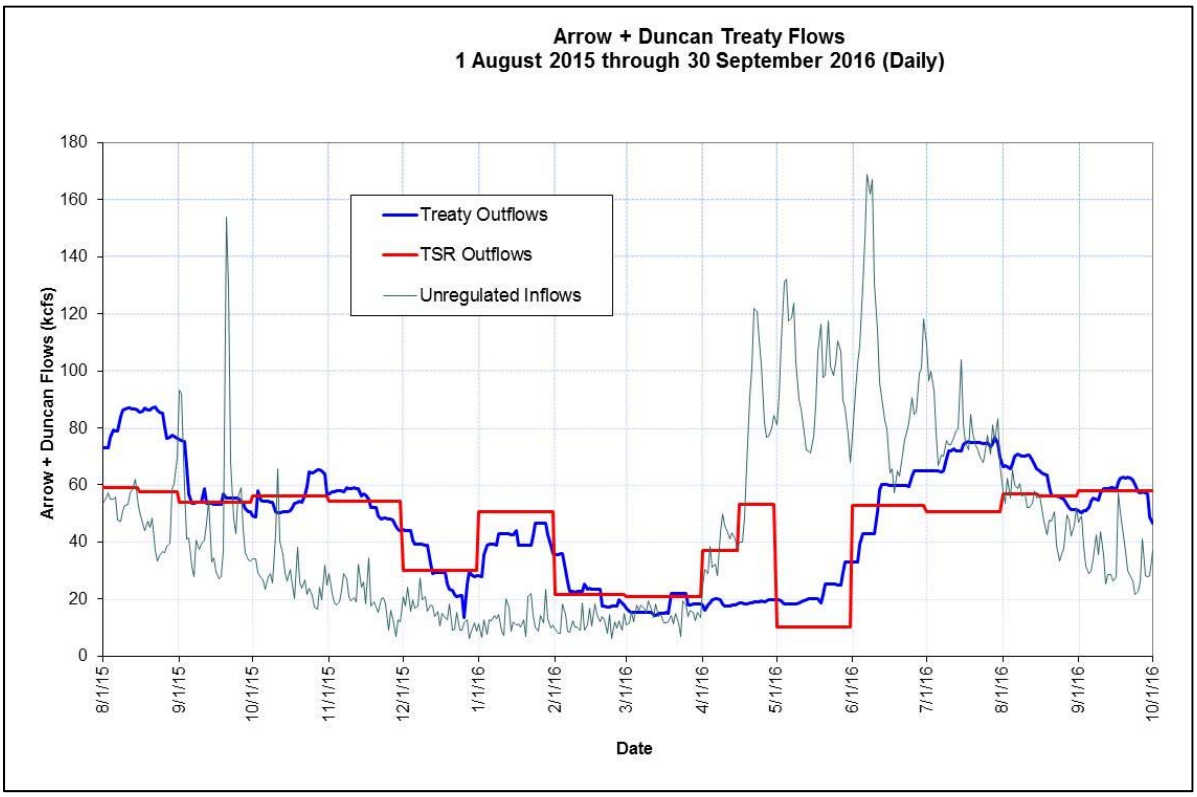


Figure 8: Keenleyside and Duncan Treaty Flows

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 composite Canadian storage, including the supplementary operating 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, resulting in some inadvertent storage, as shown in Section II, Line 9.

Figure 9: Summary of Treaty Storage Operation

Summary of Treaty Storage Operations
July 2015 through September 2016

All units in KSFD	2015							2016										
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)	5079.6	5013.5	4819.8	4736.1	3889.9	2857.1	2391.2	1217.0	931.3	737.8	741.2	1185.9	3897.1	5257.1	6133.6	6140.9	5970.9	5245.9
2) Actual Treaty Content (w/SOA's)	6005.2	5599.1	4993.8	4841.9	4009.9	2992.4	2485.4	1624.8	1310.7	1213.7	1494.1	2442.8	4769.9	6108.2	6344.8	6179.4	5994.6	5307.1
3) % full (TSR Comp.Storage/7814.6)	65.0%	64.1%	61.7%	60.6%	49.8%	36.6%	30.6%	15.6%	11.9%	9.4%	9.5%	15.2%	49.9%	67.3%	78.5%	78.6%	76.4%	67.1%
4) Final deviation from TSR	**925.6**	**585.6**	**174.0**	**105.8**	**120.0**	**135.3**	**94.2**	**407.8**	**379.4**	**475.9**	**752.9**	**1256.9**	**872.8**	**851.1**	**211.2**	**38.5**	**23.7**	**61.2**

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

	2015							2016										
Balance in each period	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
5) Short Term Libby Agreement (STLA)	0.0	0.0	0.0	0.0	49.0	49.0	7.0	-161.0	-126.0	0.0	0.0	0.0	0.0	0.0	0.0	-18.0	-84.0	-84.0
6) Non Power Uses Flow (NPU) FA	0.0	0.0	0.0	0.0	0.0	0.0	123.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	0.0	0.0	0.0	0.0
7) Arrow Summer Shaping Agreement	868.0	455.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	210.3	0.0	0.0	0.0
8) Total	868.0	455.0	0.0	0.0	49.0	49.0	130.0	343.0	378.0	504.0	504.0	504.0	504.0	504.0	210.3	-18.0	-84.0	-84.0
9. Inadvertent (Line 4 - Line 8)	**57.6**	**130.6**	**174.0**	**105.8**	**71.0**	**86.3**	**-35.8**	**64.8**	**1.4**	**-28.1**	**248.9**	**752.9**	**368.8**	**347.1**	**0.9**	**56.5**	**107.7**	**145.2**

NPU avg Feb-Mar | NPU Shaping; inadvertent does not apply

III. Summary of TSR Results (Final TSR in green)

Composite Treaty Storage TSR Content (ksfd)

	2015							2016										2016
TSR Date	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
7-Aug-15	**5079.6**	4956.1	4724.6	4273.4	3670.7	2694.6	1851.9	1081.7	718.6	348.8	354.3	620.8	2625.8	5500.0	7373.3			
20-Aug-15		**5013.5**	4799.7	4301.7	3446.2	2492.7	1631.2	969.1	444.8	92.0	97.5	363.9	2554.3	5500.0	7373.3			
4-Sep-15			**4819.8**	4396.7	3518.5	2572.9	1717.1	1014.3	574.0	219.0	224.5	491.0	2625.8	5500.0	7373.3			
18-Sep-15				4524.2	3771.6	2667.3	1816.0	1066.0	703.7	334.8	340.3	606.7	2670.4	5544.6	7417.9			
7-Oct-15				**4736.1**	4012.4	2837.7	1995.7	1156.5	785.0	415.3	420.8	687.2	2670.4	5544.6	7417.9			
21-Oct-15					3934.9	2721.8	1627.9	967.2	395.4	65.3	70.8	337.3	2527.7	5544.6	7417.9			
6-Nov-15					**3889.9**	2755.1	1758.2	1036.5	656.7	300.4	305.9	572.4	2670.4	5544.6	7417.9			
20-Nov-15						2912.3	2027.4	1124.8	756.6	386.8	392.3	658.8	2670.4	5544.6	7417.9			
10-Dec-15						**2857.1**	2310.9	1214.1	841.4	478.4	483.9	694.1	2670.4	5544.6	7417.9			
18-Dec-15							2403.5	1214.1	887.0	524.0	529.4	694.1	2670.4	5544.6	7417.9			
13-Jan-16							**2391.2**	1214.1	825.2	495.8	506.2	703.1	2823.3	5474.9	7282.6			
25-Jan-16								1234.0	874.5	536.5	549.7	703.5	2819.4	5460.7	7263.2			
10-Feb-16								**1217.0**	927.8	649.5	634.6	737.2	2869.5	5551.2	7402.1			
22-Feb-16									927.1	681.5	649.6	751.2	2878.3	5549.8	7390.2			
10-Mar-16									**931.3**	757.3	686.8	784.8	2834.4	5515.5	7314.5			
23-Mar-16										764.0	688.5	799.2	2847.1	5519.6	7315.1			
12-Apr-16										**737.8**	750.3	920.5	3002.1	5587.0	7341.0			
21-Apr-16											**741.2**	1132.8	3461.2	5700.7	7335.7			
11-May-16												**1185.9**	3884.3	5829.8	6945.8			
24-May-16													3897.1	6009.5	7268.2			
10-Jun-16													**3897.1**	5901.0	6979.7			
20-Jun-16														5329.0	6493.6	6480.5	6392.9	
7-Jul-16														**5257.1**	6264.9	6216.5	6103.7	
21-Jul-16															6172.8	6131.5	6013.1	5346.3
5-Aug-16															**6133.6**	6069.7	5948.4	5266.3
22-Aug-16																**6140.9**	6037.3	5360.4
8-Sep-16																	**5970.9**	5234.1
22-Sep-16																		5323.5
6-Oct-16																		**5245.9**
Proportional Draft Point (PDP)	3.723	4.846	4.917	4.776	4.727	4.563	4.307	2.995	1.000	1.000	1.000	1.000	1.000	2.921	3.425	4.485	4.557	4.605

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	2.5	27.3	13.6	7.8	101.9
February	2.4	27.9	13.9	7.8	102.7
March	2.4	27.1	13.6	8.0	106.7
April	2.4	27.8	13.6	8.2	107.1
May	2.5	27.1	13.1	7.2	107.1
June	2.5	26.3	12.6	7.9	100.8
Actual	2.4	26.5	13.2	6.7	96.7

Table 1: Unregulated Runoff Volume Forecasts Million Acre-feet

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

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.1	22.1	11.0	6.4	82.6
February	2.0	22.6	11.2	6.3	83.2
March	2.0	22.0	11.0	6.5	86.5
April	2.0	22.5	11.0	6.7	86.9
May	2.1	22.0	10.7	5.8	86.8
June	2.1	21.3	10.2	6.4	81.7
Actual	2.0	21.4	10.7	5.4	78.4

Table 2M (metric): 2016 Mica Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			11.3	11.6	11.1	10.8	9.1	5.9
PROBABLE DATE-31JULY INFLOW, hm3	**		11310.6	11599.8	11082.6	10805.4	9131.9	5912.5
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/		9507.9	10323.3	9969.2	9777.5	8149.9	4941.1
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		9507.9					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		3909.8					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3036.4					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		738.6					
JAN31 ORC, m	7/		738.6					
BASE ECC, m	8/	743.6						
LOWER LIMIT, m		733.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		9308.3	10106.5				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		3696.9	3669.9				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3023.2	2197.9				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		738.6	736.3				
FEB28 ORC, m	7/		737.5	736.3				
BASE ECC, m	8/	737.5						
LOWER LIMIT, m		729.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		9080.1	9858.7	9720.0			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0			
MIN APR1-JUL31 OUTFLOW, hm3	4/		3469.4	3442.4	3442.4			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3023.9	2218.2	2356.9			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		738.6	736.3	736.7			
MAR31 ORC, m	7/		737.6	736.3	736.7			
BASE ECC, m	8/	737.6						
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/		8604.7	9342.6	9211.5	9269.1		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		3249.2	3222.2	3222.2	3222.2		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3279.1	2514.1	2645.2	2587.7		
VRC APR30 RESERVOIR CONTENT, METERS	6/		739.3	737.2	737.5	737.4		
APR30 ORC, m	7/		737.5	737.2	737.5	737.4		
BASE ECC, m	8/	737.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		6807.7	7391.5	7287.5	7342.9	6454.7	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0	85.0	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		3021.7	2994.6	2994.6	2994.6	2994.6	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4848.5	4237.7	4341.7	4286.3	5174.5	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		743.5	741.9	742.2	742.0	744.4	
MAY31 ORC, m	7/		741.0	741.0	741.0	741.0	741.0	
BASE ECC, m	8/	741.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		3441.9	3737.0	3688.6	3715.4	3268.1	2500.2
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		453.1	461.7	453.1	453.1	453.1	453.1
MIN JUL1-JUL31 OUTFLOW, hm3	4/		1824.9	1820.3	1820.3	1820.3	1820.3	1820.3
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7017.6	6717.8	6766.2	6739.4	7186.7	7954.6
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.0	748.3	748.4	748.3	749.4	751.3
JUN30 ORC, m	7/		748.1	748.1	748.1	748.1	748.1	748.1
BASE ECC, m	8/	748.1						
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 FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 2: 2016 Mica Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			9169.6	9404.0	8984.7	8760.0	7403.3	4793.3
PROBABLE DATE-31JULY INFLOW, KSFD	**		4623.0	4741.2	4529.8	4416.5	3732.5	2416.6
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/		3886.2	4219.4	4074.7	3996.4	3331.1	2019.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3886.2					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1598.1					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1241.1					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2423.3					
JAN31 ORC, FT	7/		2423.3					
BASE ECC, FT	8/	2439.5						
LOWER LIMIT, FT		2407.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		3804.6	4130.8				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1511.1	1500.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1235.7	898.4				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2423.2	2415.6				
FEB28 ORC, FT	7/		2419.7	2415.6				
BASE ECC, FT	8/	2419.7						
LOWER LIMIT, FT		2394.7						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3711.3	4029.6	3972.8			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1418.1	1407.0	1407.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1235.9	906.6	963.4			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2423.2	2415.8	2417.1			
MAR31 ORC, FT	7/		2419.9	2415.8	2417.1			
BASE ECC, FT	8/	2419.9						
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/		3517.0	3818.6	3765.0	3788.5		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1328.1	1317.0	1317.0	1317.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1340.3	1027.6	1081.2	1057.7		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2425.5	2418.5	2419.7	2419.2		
APR30 ORC, FT	7/		2419.5	2418.5	2419.5	2419.2		
BASE ECC, FT	8/	2419.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2782.5	3021.1	2978.6	3001.3	2638.2	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0	3000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1235.1	1224.0	1224.0	1224.0	1224.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1981.7	1732.1	1774.6	1751.9	2115.0	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2439.3	2434.0	2434.9	2434.4	2442.1	
MAY31 ORC, FT	7/		2431.2	2431.2	2431.2	2431.2	2431.2	
BASE ECC, FT	8/	2431.2						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1406.8	1527.4	1507.6	1518.6	1335.8	1021.9
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		16000.0	16305.3	16000.0	16000.0	16000.0	16000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		745.9	744.0	744.0	744.0	744.0	744.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2868.3	2745.8	2765.6	2754.6	2937.4	3251.3
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2457.3	2454.9	2455.3	2455.0	2458.7	2464.8
JUN30 ORC, FT	7/		2454.4	2454.4	2454.4	2454.4	2454.4	2454.4
BASE ECC, FT	8/	2454.4						
JUL 31 ORC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (3529.2 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 3M (metric): 2016 Keenleyside 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			24.1	24.7	23.4	23.1	19.0	11.7
& IN hm3	**		24101.5	24699.9	23429.4	23071.2	19006.4	11742.0
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/		20474.2					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		7322.7					
UPSTREAM DISCHARGE, hm3	4/		5598.2					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		1204.5					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		423.5					
JAN31 ORC, m	7/		423.5					
BASE ECC, m	8/	425.5						
LOWER LIMIT, m		421.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		19982.8	21492.0				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		6967.9	6967.9				
UPSTREAM DISCHARGE, hm3	4/		5992.5	6436.6				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		1735.4	670.4				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		424.9	422.0				
FEB28 ORC, m	7/		424.6	422.0				
BASE ECC, m	8/	424.6						
LOWER LIMIT, m		420.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		19368.6	20831.3	20461.9			
MIN APR1-JUL31 OUTFLOW, hm3	3/		6588.7	6588.7	6588.7			
UPSTREAM DISCHARGE, hm3	4/		5976.3	6416.4	6277.6			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		1954.3	931.6	1162.2			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		425.4	422.7	423.3			
MAR31 ORC, m	7/		422.5	422.5	422.5			
BASE ECC, m	8/	422.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		17955.9	19311.9	18943.1	19529.4		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		6221.7	6221.7	6221.7	6221.7		
UPSTREAM DISCHARGE, hm3	4/		6016.9	6120.4	6016.9	6046.9		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3040.6	1788.0	2053.4	1497.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		428.1	425.0	425.7	424.2		
APR30 ORC, Fm	7/		424.8	424.8	424.8	424.2		
BASE ECC, m	8/	424.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		13308.2	14313.3	14049.1	14488.9	12790.0	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		5842.5	5842.5	5842.5	5842.5	5842.5	
UPSTREAM DISCHARGE, hm3	4/		4720.2	4720.2	4720.2	4720.2	4720.2	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		6012.3	5007.3	5271.4	4831.7	6530.6	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		434.7	432.5	433.1	432.2	435.7	
MAY31 ORC, m	7/		432.5	432.5	432.5	432.2	432.5	
BASE ECC, m	8/	432.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		6203.7	6672.2	6560.5	6769.9	5981.3	4707.2
MIN JUL1-JUL31 OUTFLOW, hm3	3/		3640.5	3640.5	3640.5	3640.5	3640.5	3640.5
UPSTREAM DISCHARGE, hm3	4/		1976.1	1976.1	1976.1	1976.1	1976.1	1976.1
VRC JUN30 RESERVOIR CONTENT, hm3	5/		8170.8	7702.3	7814.0	7604.6	8393.2	9667.3
VRC JUN30 RESERVOIR CONTENT, METERS	6/		439.0	438.1	438.3	437.9	439.4	440.1
JUN30 ORC, m	7/		439.0	438.1	438.3	437.9	439.4	439.5
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 FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 3: 2016 Keenleyside 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			19539.2	20024.3	18994.3	18703.9	15408.6	9519.3
& IN KSFD	**		9851.0	10095.6	9576.3	9429.9	7768.5	4799.3
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/		8368.4					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		2993.0					
UPSTREAM DISCHARGE, KSFD	4/		2288.1					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		492.3					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1389.3					
JAN31 ORC, FT	7/		1389.3					
BASE ECC, FT	8/	1395.9						
LOWER LIMIT, FT		1381.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		8167.6	8784.4				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		2848.0	2848.0				
UPSTREAM DISCHARGE, KSFD	4/		2449.3	2630.8				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		709.3	274.0				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1393.9	1384.5				
FEB28 ORC, FT	7/		1393.0	1384.4				
BASE ECC, FT	8/	1392.9						
LOWER LIMIT, FT		1379.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		7916.5	8514.4	8363.4			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		2693.0	2693.0	2693.0			
UPSTREAM DISCHARGE, KSFD	4/		2442.7	2622.6	2565.8			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		798.8	380.8	475.0			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1395.7	1386.9	1388.9			
MAR31 ORC, FT	7/		1386.3	1386.3	1386.3			
BASE ECC, FT	8/	1386.3						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7339.1	7893.4	7742.6	7982.3		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		2543.0	2543.0	2543.0	2543.0		
UPSTREAM DISCHARGE, KSFD	4/		2459.3	2501.6	2459.3	2471.5		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1242.8	730.8	839.3	611.9		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1404.4	1394.3	1396.5	1391.8		
APR30 ORC, FT	7/		1393.8	1393.8	1393.8	1391.8		
BASE ECC, FT	8/	1393.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5439.5	5850.3	5742.3	5922.1	5227.7	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		2388.0	2388.0	2388.0	2388.0	2388.0	
UPSTREAM DISCHARGE, KSFD	4/		1929.3	1929.3	1929.3	1929.3	1929.3	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2457.4	2046.6	2154.6	1974.8	2669.2	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1426.1	1419.1	1421.0	1417.9	1429.6	
MAY31 ORC, FT	7/		1419.0	1419.0	1419.0	1417.9	1419.0	
BASE ECC, FT	8/	1419.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2535.6	2727.1	2681.5	2767.1	2444.7	1924.0
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1488.0	1488.0	1488.0	1488.0	1488.0	1488.0
UPSTREAM DISCHARGE, KSFD	4/		807.7	807.7	807.7	807.7	807.7	807.7
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3339.7	3148.2	3193.8	3108.2	3430.6	3951.3
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1440.3	1437.3	1438.0	1436.7	1441.7	1444.0
JUN30 ORC, FT	7/		1440.3	1437.3	1438.0	1436.7	1441.7	1442.0
BASE ECC, FT	8/	1444.0						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT.
5/ MAXIMUM(FULL CONTENT (3579.6 KSFD) MINUS 2/ PLUS 3/ MINUS /4 OR LOWER LIMIT)
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF THE ARC OR CRC1 IN DOP

Table 4M (metric): 2016 Duncan Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			2.2	2.1	2.1	2.0	1.8	1.2
& IN hm3	**		2206.8	2118.3	2065.9	2019.4	1781.6	1180.0
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/		1897.9	1863.0	1809.0	1789.8	1568.9	989.2
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		1897.9					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		308.7					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		137.6					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		550.5					
JAN31 ORC, m	7/		553.5					
BASE ECC, m	8/	560.0						
LOWER LIMIT, m		553.5						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		1860.0	1825.8				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		301.6	300.2				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		168.4	201.2				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		551.2	551.9				
FEB28 ORC, m	7/		551.2	551.9				
BASE ECC, m	8/	553.4						
LOWER LIMIT, m		549.6						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		1814.4	1781.1	1765.6			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8			
MIN APR1-JUL31 OUTFLOW, hm3	4/		294.0	292.6	292.6			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		206.4	238.4	253.8			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		552.0	552.7	553.0			
MAR31 ORC, m	7/		551.0	551.6	552.0			
BASE ECC, m	8/	553.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.7	89.7	91.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		1700.5	1669.3	1655.3	1677.0		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		286.7	285.3	285.3	285.3		
VRC APR30 RESERVOIR CONTENT, hm3	5/		312.9	342.8	356.8	335.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		554.2	554.8	555.0	554.6		
APR30 ORC, m	7/		551.0	551.6	552.0	551.8		
BASE ECC, m	8/	554.6						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		1277.3	1253.8	1242.8	1258.2	1178.3	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8	2.8	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		279.1	277.7	277.7	277.7	277.7	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		728.6	750.7	761.7	746.3	826.2	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		561.6	562.0	562.2	561.9	563.2	
MAY31 ORC, m	7/		559.9	559.9	559.9	559.9	559.9	
BASE ECC, m	8/	559.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		614.9	603.6	598.8	605.0	568.0	475.8
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		34.0	34.0	34.0	34.0	34.0	34.0
MIN JUL1-JUL31 OUTFLOW, hm3	4/		191.0	189.6	189.6	189.6	189.6	189.6
VRC JUN30 RESERVOIR CONTENT, hm3	5/		1302.9	1312.8	1317.6	1311.5	1348.5	1440.6
VRC JUN30 RESERVOIR CONTENT, METERS	6/		570.6	570.7	570.8	570.7	571.3	572.6
JUN30 ORC, m	7/		570.5	570.5	570.5	570.5	570.5	570.5
BASE ECC, m	8/	570.5						
JUL 31 ECC, m			576.7	576.7	576.7	576.7	576.7	576.7

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (1726.81 hm3) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER THAN THE ARC OR CRC1 IN DOP

Table 4: 2016 Duncan Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1789.1	1717.3	1674.8	1637.2	1444.4	956.6
& IN KSFD	**		902.0	865.8	844.4	825.4	728.2	482.3
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/		775.7	761.5	739.4	731.5	641.3	404.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		775.7					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		126.2					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		56.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1806.1					
JAN31 ORC, FT	7/		1815.8					
BASE ECC, FT	8/	1837.2						
LOWER LIMIT, FT		1815.8						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		760.2	746.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		123.3	122.7				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		68.8	82.2				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1808.3	1810.7				
FEB28 ORC, FT	7/		1808.4	1810.7				
BASE ECC, FT	8/	1815.6						
LOWER LIMIT, FT		1803.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		741.6	728.0	721.7			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		120.2	119.6	119.6			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		84.4	97.4	103.7			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1811.1	1813.2	1814.3			
MAR31 ORC, FT	7/		1807.8	1809.7	1811.2			
BASE ECC, FT	8/	1817.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.7	89.7	91.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		695.1	682.3	676.6	685.5		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		117.2	116.6	116.6	116.6		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		127.9	140.1	145.8	136.9		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1818.2	1820.1	1821.0	1819.6		
APR30 ORC, FT	7/		1807.8	1809.7	1811.2	1810.3		
BASE ECC, FT	8/	1819.7						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		522.1	512.5	508.0	514.3	481.6	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		114.1	113.5	113.5	113.5	113.5	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		297.8	306.8	311.3	305.0	337.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1842.6	1843.8	1844.4	1843.5	1847.8	
MAY31 ORC, FT	7/		1836.8	1836.8	1836.8	1836.8	1836.8	
BASE ECC, FT	8/	1836.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		251.3	246.7	244.7	247.3	232.1	194.5
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		1200.0	1200.0	1200.0	1200.0	1200.0	1200.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		78.1	77.5	77.5	77.5	77.5	77.5
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		532.5	536.6	538.6	536.0	551.2	588.8
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1872.0	1872.5	1872.7	1872.4	1874.2	1878.6
JUN30 ORC, FT	7/		1871.7	1871.7	1871.7	1871.7	1871.7	1871.7
BASE ECC, FT	8/	1871.7						
JUL 31 ECC, FT			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (705.8 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 5M (metric): 2016 Libby Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			7.7	7.8	8.1	8.3	7.4	7.4
PROBABLE DATE-31JULY INFLOW, hm3			7738.8	7814.2	8058.4	8344.6	7390.0	8080.4
95% FORECAST ERROR FOR DATE, hm3			2246.2	1813.2	1721.9	1250.7	1217.4	1186.6
OBSERVED JAN1-DATE INFLOW, IN hm3			0.0	233.2	480.3	841.4	2270.4	4434.2
95% CONF.DATE-31JULY INFLOW, hm3	1/		5492.9	5767.9	5856.2	6252.5	3901.8	2459.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		5322.6					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		2681.5					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3501.1					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		733.7					
JAN31 ORC, m	7/		733.7					
BASE ECC, m	9/	736.4						
LOWER LIMIT, m		720.5						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		5168.7	5600.5				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		2397.7	2397.7				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3371.2	2939.3				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		732.7	729.4				
FEB28 ORC, m	7/		732.7	729.4				
BASE ECC, m	9/	735.5						
LOWER LIMIT, m		709.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		4976.4	5392.8	5639.4			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, hm3	4/		2094.3	2094.3	2094.3			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3260.1	2843.7	2597.1			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		731.9	728.7	726.6			
MAR31 ORC, m	7/		731.9	728.7	726.6			
BASE ECC, m	9/	734.7						
LOWER LIMIT, m		700.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		4526.0	4902.7	5124.2	5683.5		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3	113.3		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		1800.7	1800.7	1800.7	1800.7		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3416.9	3040.1	2818.7	2259.4		
VRC APR30 RESERVOIR CONTENT, METERS	6/		733.0	730.2	728.5	723.6		
APR30 ORC, m	7/		733.0	730.2	728.5	723.6		
BASE ECC, m	9/	734.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	61.0	67.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		3037.5	3287.7	3437.5	3814.0	2618.1	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		226.5	226.5	226.5	226.5	226.5	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		1497.3	1497.3	1497.3	1497.3	1497.3	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4602.1	4351.8	4202.0	3825.5	5021.4	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		740.8	739.2	738.3	735.8	743.3	
MAY31 ORC, m	7/		740.8	739.2	738.3	735.8	741.5	
BASE ECC, m	9/	741.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.8	20.3	20.9	21.8	23.9	35.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		1087.5	1170.9	1224.0	1363.0	932.6	875.6
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		339.8	339.8	339.8	339.8	339.8	339.8
MIN JUL1-JUL31 OUTFLOW, hm3	4/		910.1	910.1	910.1	910.1	910.1	910.1
VRC JUN30 RESERVOIR CONTENT, hm3	5/		5964.8	5881.4	5828.3	5689.3	6119.7	6142.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		748.5	748.1	747.8	747.1	749.4	749.5
JUN30 ORC, m	7/		748.5	748.1	747.8	747.1	749.4	749.5
BASE ECC, m	9/	749.5						
JUL 31 ORC, m			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, km3	8/		116.1	117.4	126.9	129.1	129.1	123.5

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: 2016 Libby Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, KAF			6274.0	6335.0	6533.0	6765.0	5991.0	6550.9
PROBABLE JAN-31JULY INFLOW, KSFD			3163.1	3193.9	3293.7	3410.7	3020.5	3302.7
95% FORECAST ERROR FOR DATE, KSFD			918.1	741.1	703.8	511.2	497.6	485.0
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	95.3	196.3	343.9	928.0	1812.4
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2245.1	2357.5	2393.6	2555.6	1594.8	1005.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		2175.5					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1096.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1431.0					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2407.0					
JAN31 ORC, FT	7/		2407.0					
BASE ECC, FT	9/	2415.9						
LOWER LIMIT, FT		2363.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		2112.6	2289.1				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		980.0	980.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1377.9	1201.4				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2403.9	2393.1				
FEB28 ORC, FT	7/		2403.9	2393.1				
BASE ECC, FT	9/	2413.1						
LOWER LIMIT, FT		2327.1						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		2034.0	2204.2	2305.0			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		856.0	856.0	856.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1332.5	1162.3	1061.5			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2401.3	2390.6	2383.8			
MAR31 ORC, FT	7/		2401.3	2390.6	2383.8			
BASE ECC, FT	9/	2410.3						
LOWER LIMIT, FT		2297.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1849.9	2003.9	2094.4	2323.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0	4000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		736.0	736.0	736.0	736.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1396.6	1242.6	1152.1	923.5		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2405.0	2395.7	2390.0	2374.0		
APR30 ORC, FT	7/		2405.0	2395.7	2390.0	2374.0		
BASE ECC, FT	9/	2409.3						
		2287.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	61.0	67.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1241.5	1343.8	1405.0	1558.9	1070.1	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		8000.0	8000.0	8000.0	8000.0	8000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		612.0	612.0	612.0	612.0	612.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1881.0	1778.7	1717.5	1563.6	2052.4	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2430.4	2425.3	2422.3	2414.2	2438.6	
MAY31 ORC, FT	7/		2430.4	2425.3	2422.3	2414.2	2432.7	
BASE ECC, FT	9/	2432.7						
		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/		444.5	478.6	500.3	557.1	381.2	357.9
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		12000.0	12000.0	12000.0	12000.0	12000.0	12000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		372.0	372.0	372.0	372.0	372.0	372.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2438.0	2403.9	2382.2	2325.4	2501.3	2510.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2455.8	2454.4	2453.4	2451.0	2458.6	2459.0
JUN30 ORC, FT	7/		2455.8	2454.4	2453.4	2451.0	2458.6	2459.0
BASE ECC, FT	9/	2459.0						
		2287.0						
JUL 31 ORC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		94.1	95.2	102.9	104.7	104.7	100.1

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW.
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
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6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
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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 on April 2016 forecast

Upstream Storage Corrections	**Metric (km^3)**	**English (Maf)**
Mica	8.281	6.714
Arrow	4.441	3.600
Duncan	1.725	1.399
Libby	2.917	2.365
Hungry Horse	0.426	0.345
Flathead Lake	0.617	0.500
Noxon Rapids	0.000	0.000
Pend Oreille Lake	0.617	0.500
Grand Coulee	4.141	3.357
Brownlee	0.462	0.374
Dworshak	0.849	0.689
John Day	0.195	0.158
Total Upstream Storage Corrections	24.670	20.001

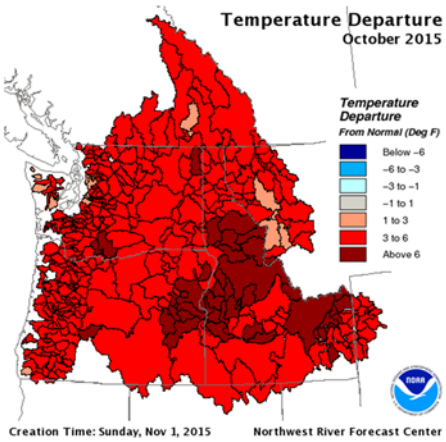
Adjusted TDA May-Aug Runoff Volume	**Metric (km^3)**	**English (Maf)**
TDA May-Aug Runoff Volume (1May Forecast)	90.246	73.164
Less Estimated Depletions	-2.502	-2.028
Less Total Upstream Storage Corrections	-24.670	-20.001
Adjusted TDA May-Aug Runoff Volume	63.074	51.135

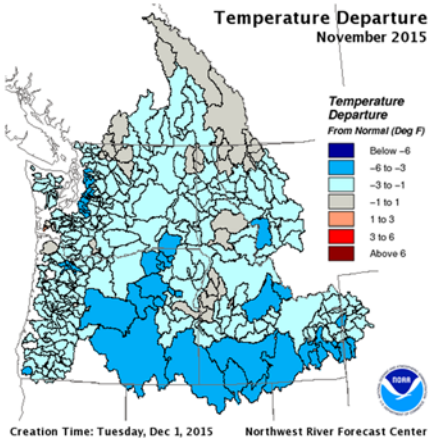
Initial Controlled Flow	**m^3/s**	**kcfs**
Determined using 'Adjusted TDA May-Aug Runoff Volume' and Chart 1 of the Flood Control Operating Plan	**9090.1**	**321.0**

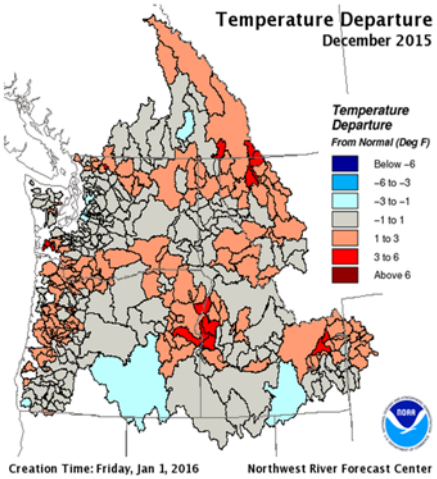
VIII - CHARTS

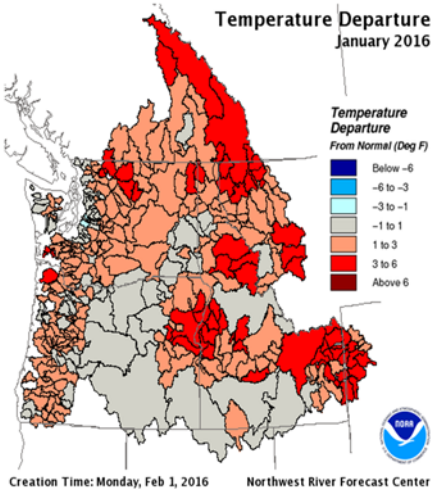
Chart 1: Pacific Northwest Monthly Temperature Departures

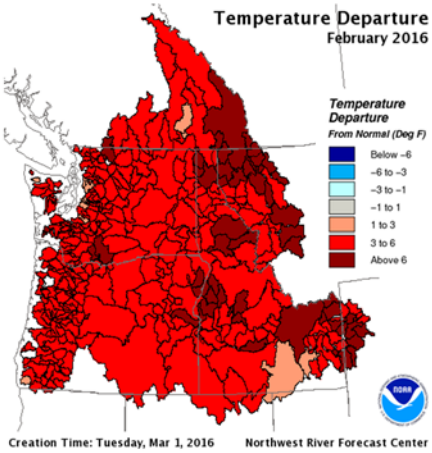
October – March











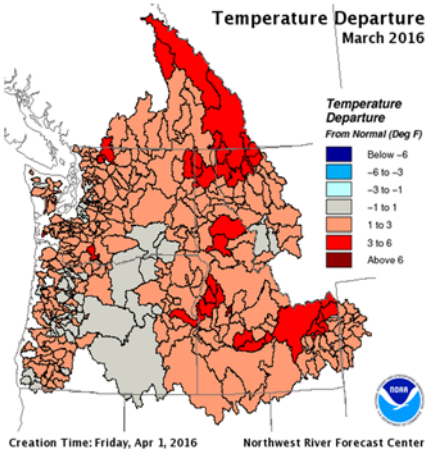
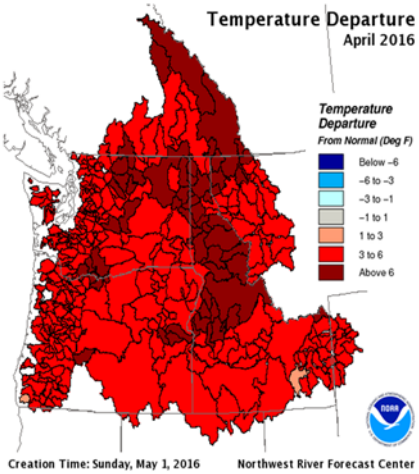
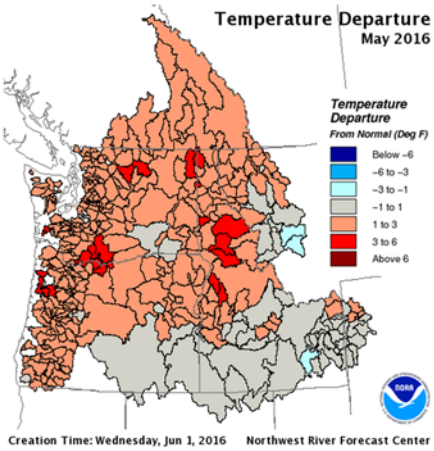
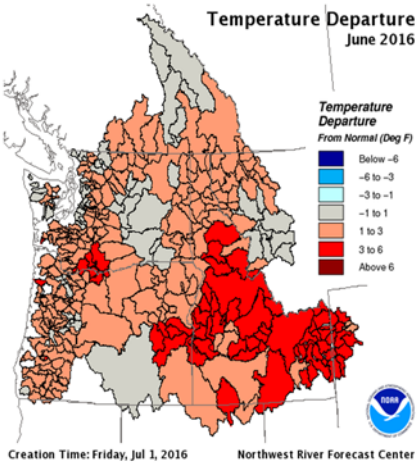
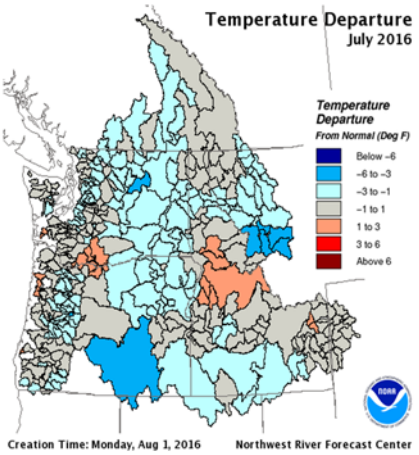


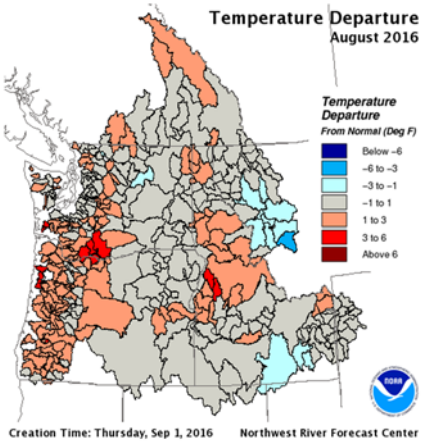
Chart 1: Pacific Northwest Monthly Temperature Departures (Continued)
April – September











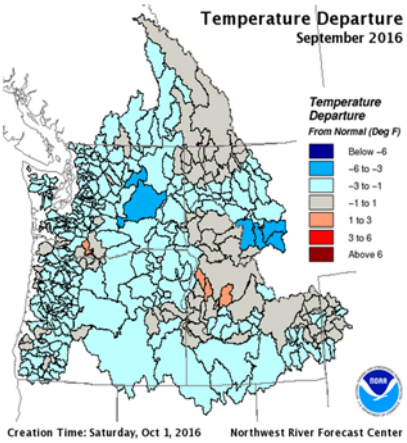
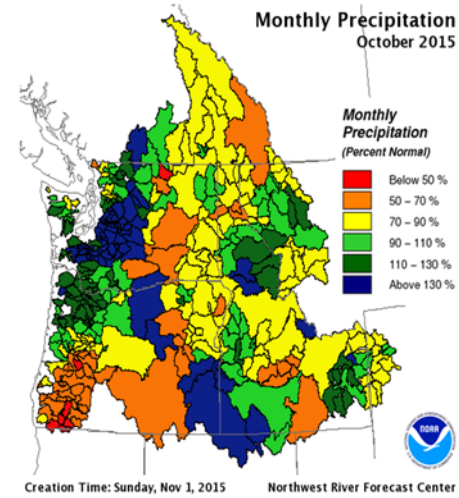
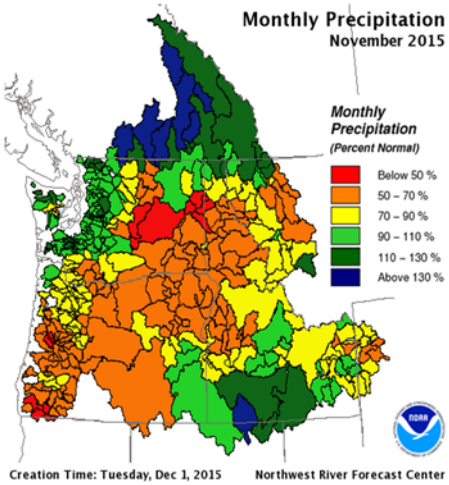
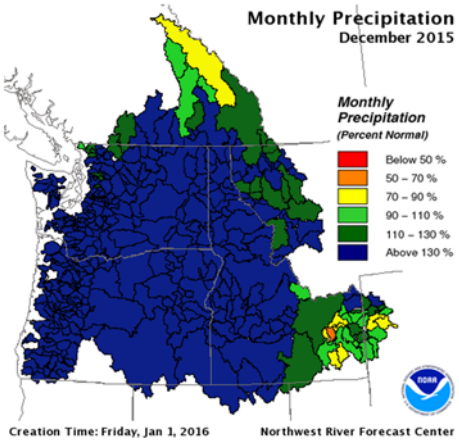
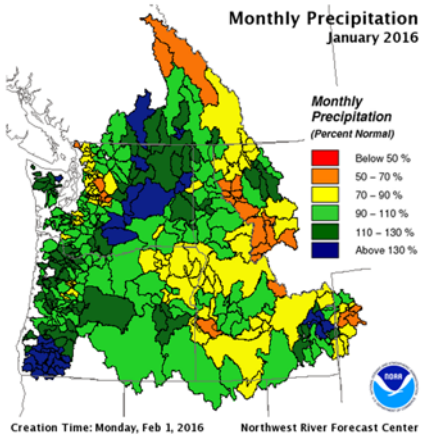


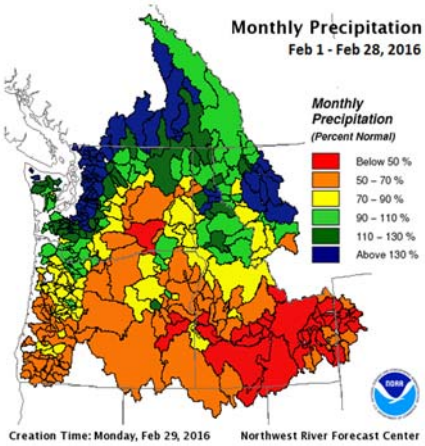
Chart 1 A: Pacific Northwest Monthly Precipitation Departures October – March











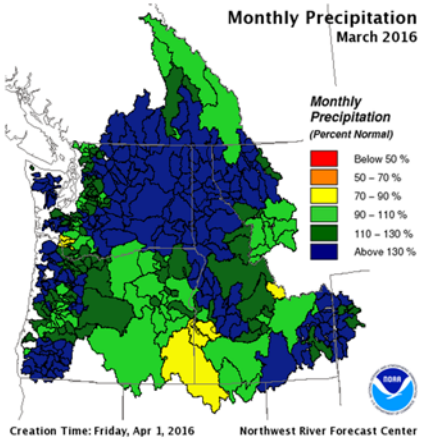
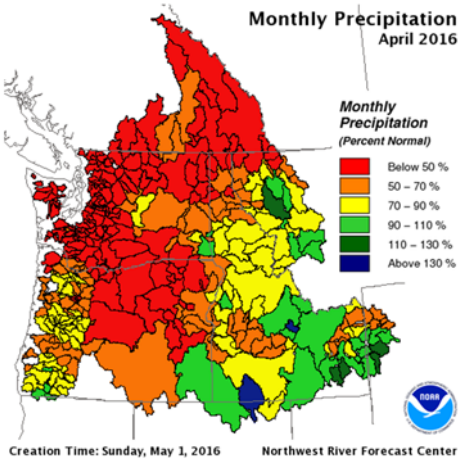
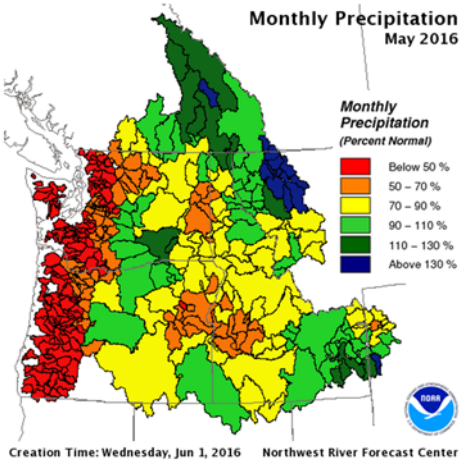
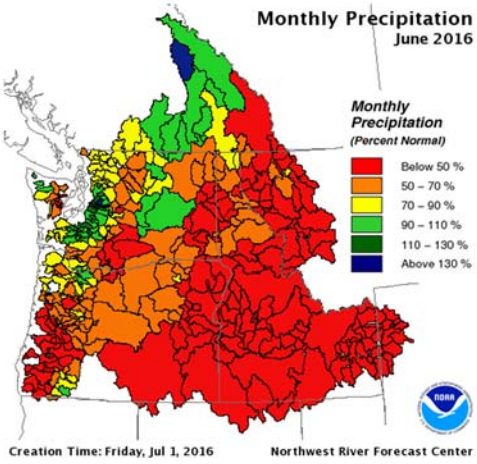
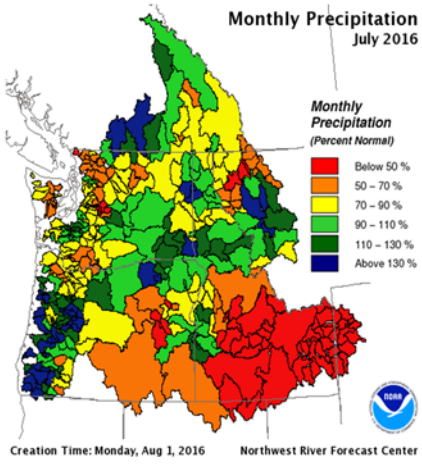


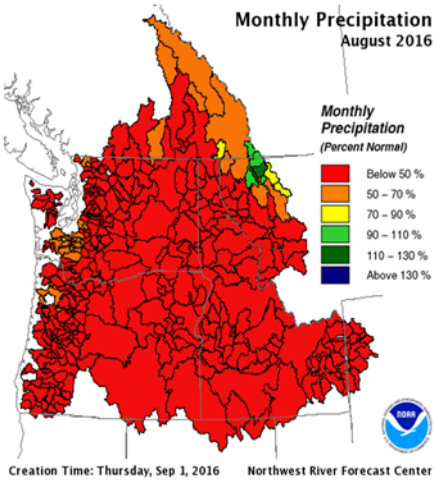
Chart 1 A: Pacific Northwest Monthly Precipitation Departures (Continued)
April – September











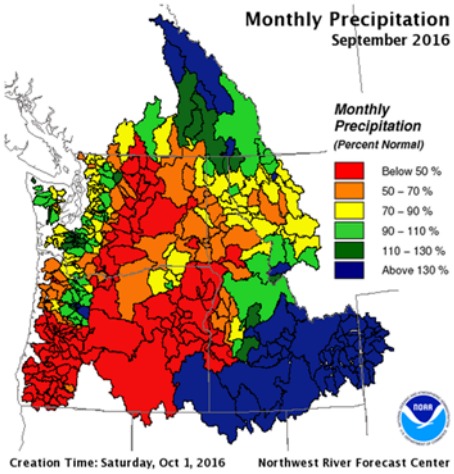


Chart 2: Seasonal Precipitation Columbia River Basin

October 2014 – September 2015

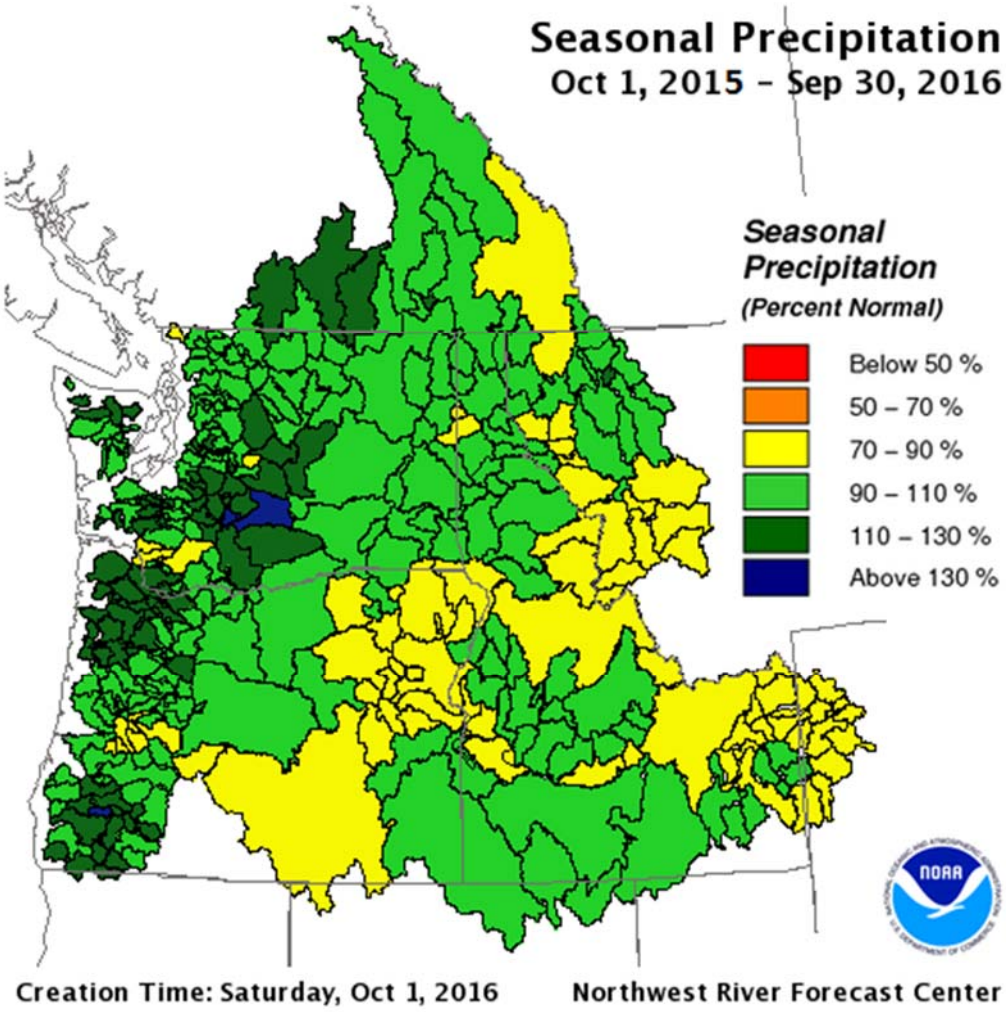
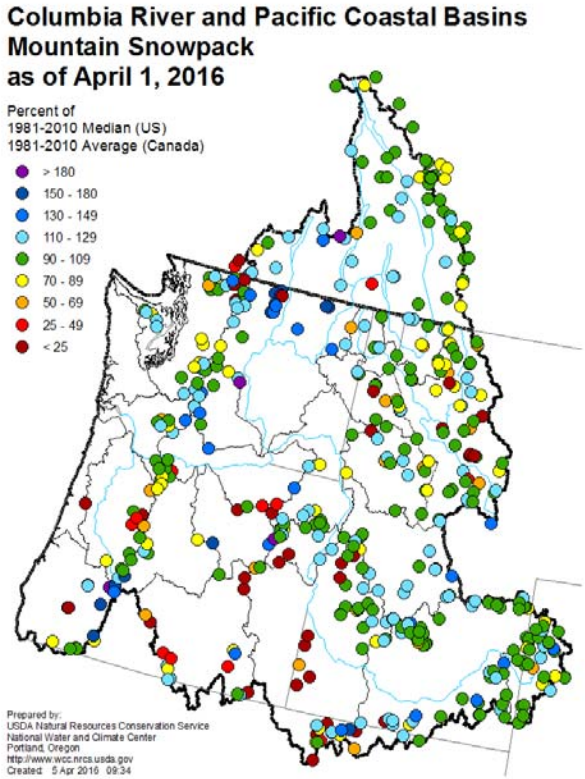


Chart 3: Columbia Basin Snowpack



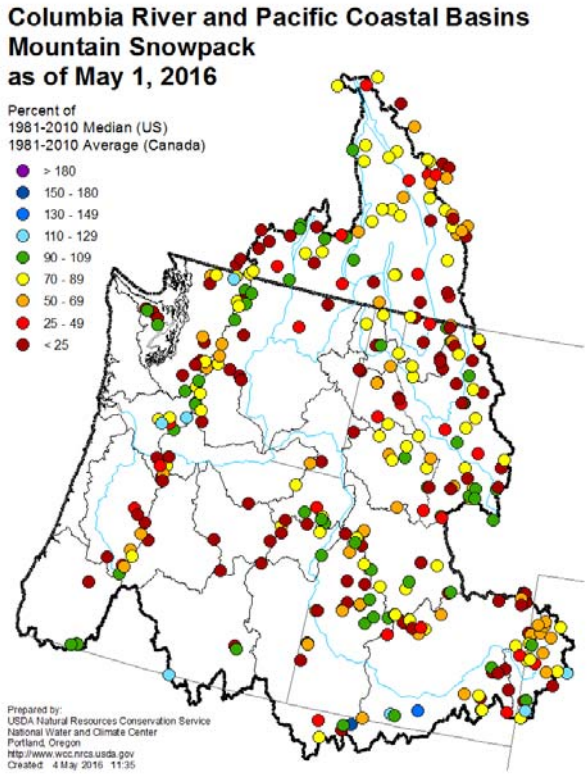


Chart 4: Accumulated Precipitation for WY 2016

At Primary Columbia River Basins

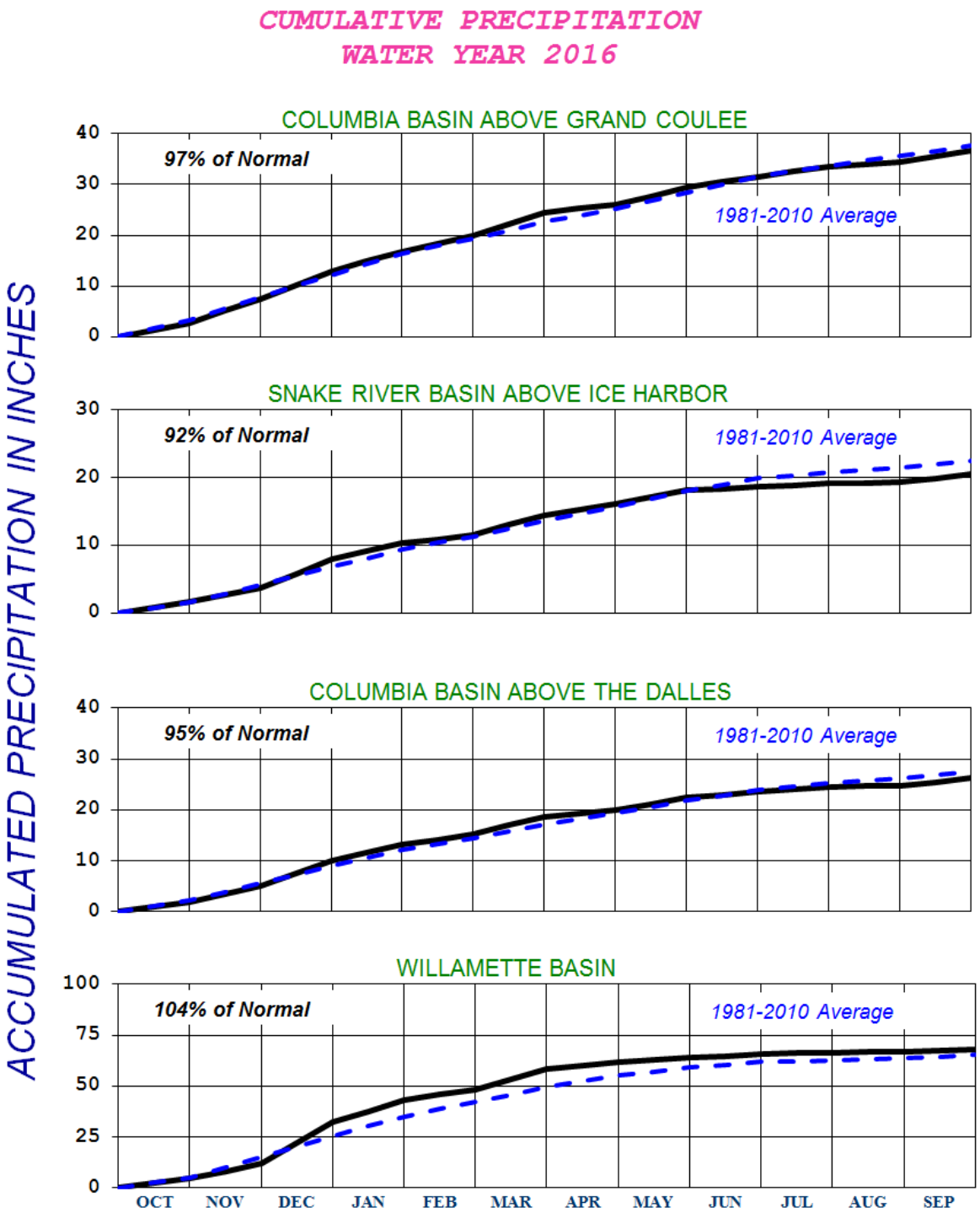
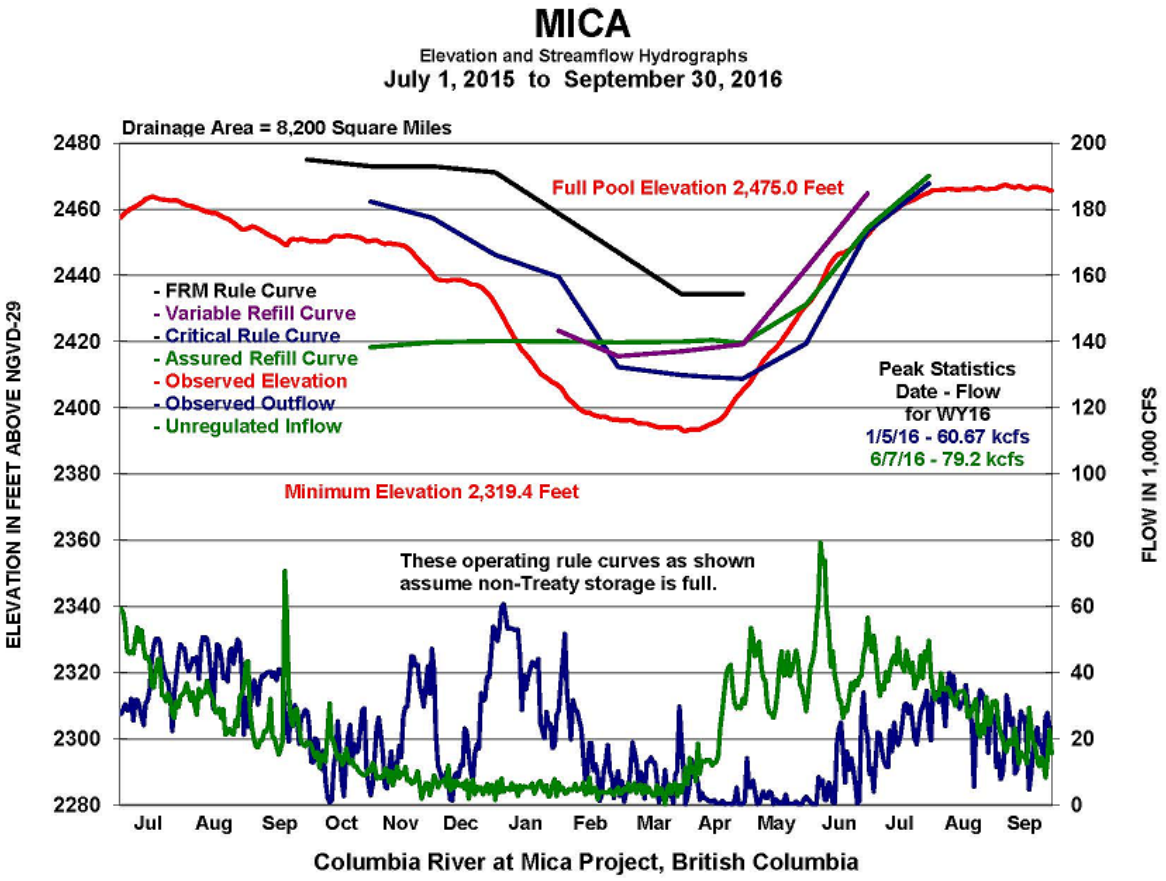


Chart 5: Regulation of Mica

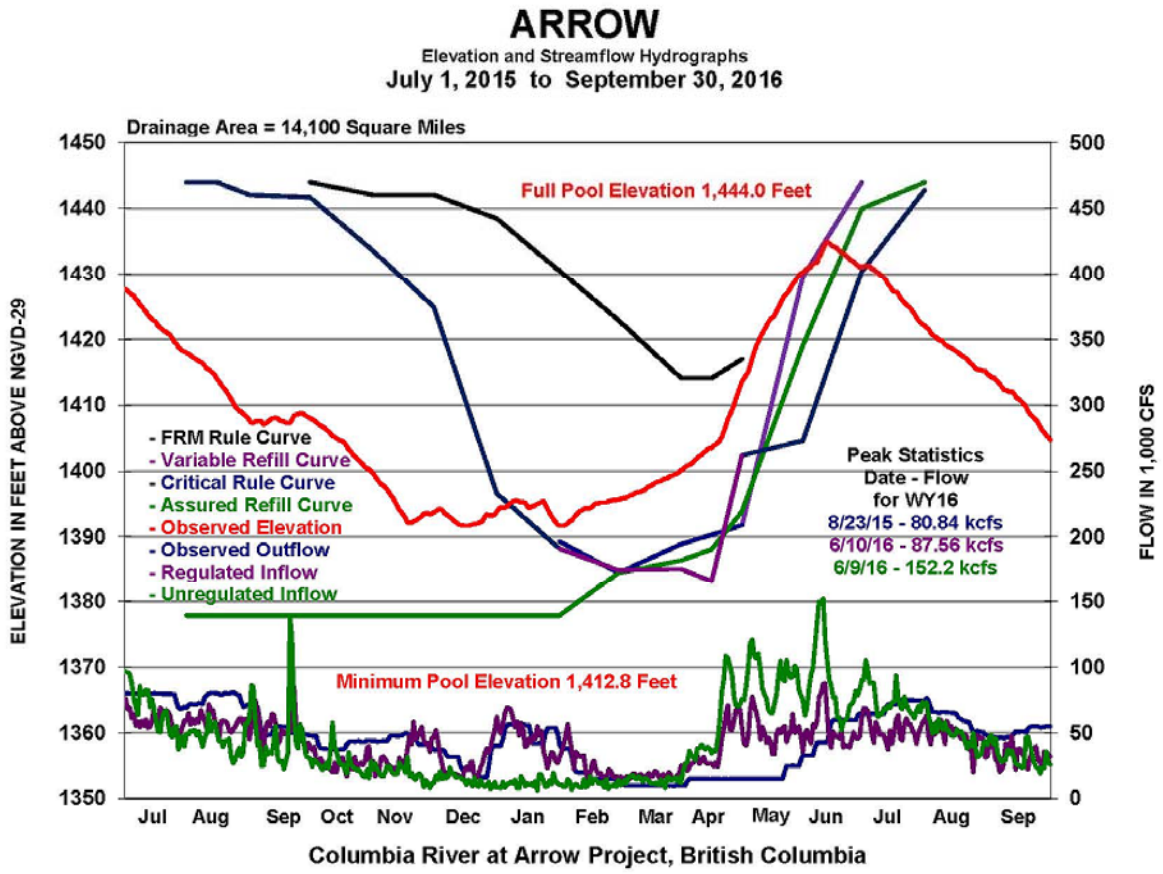
1 July 2015 – 30 September 2016



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 6: Regulation of Keenleyside

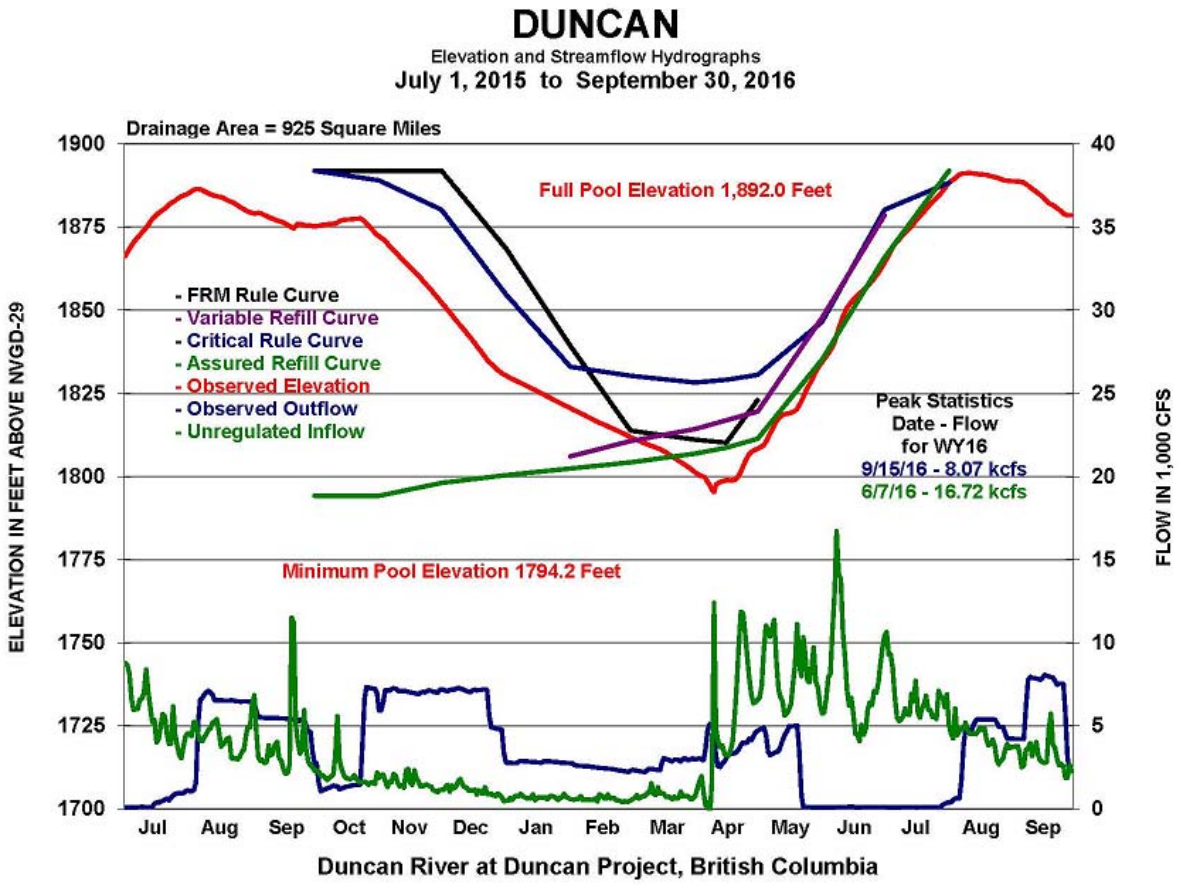
1 July 2015 – 30 September 2016



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 7: Regulation of Duncan

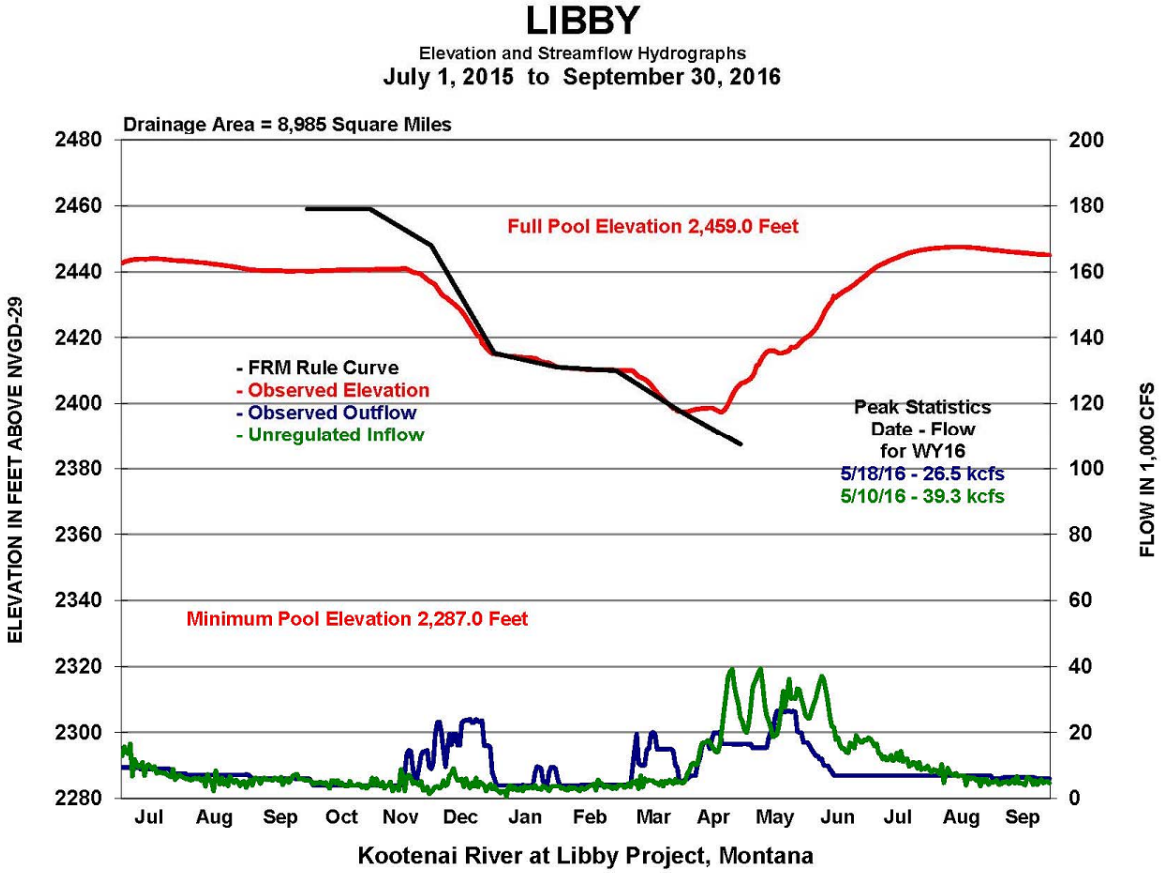
1 July 2015 – 30 September 2016



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 8: Regulation of Libby

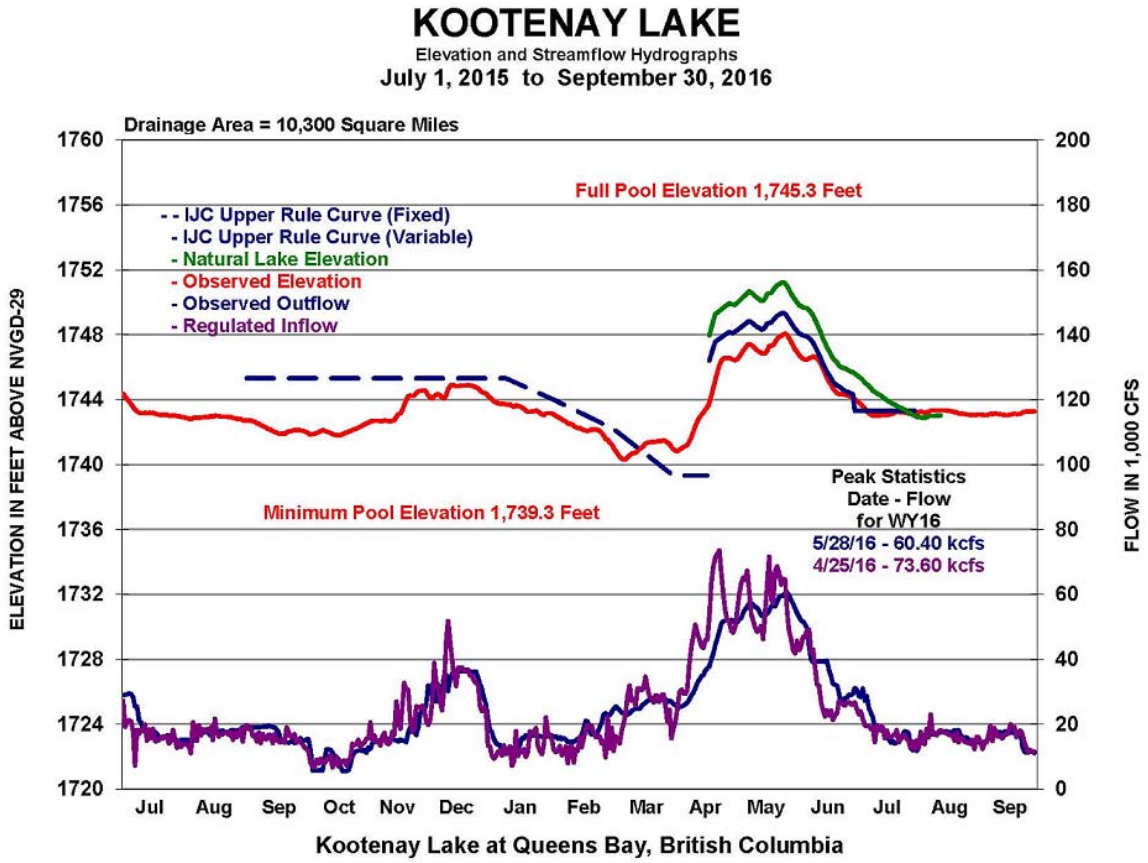
1 July 2015 – 30 September 2016



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 9: Regulation of Kootenay Lake

1 July 2015 – 30 September 2016



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 10: Columbia River at Birchbank

1 August 2015 – 30 September 2016

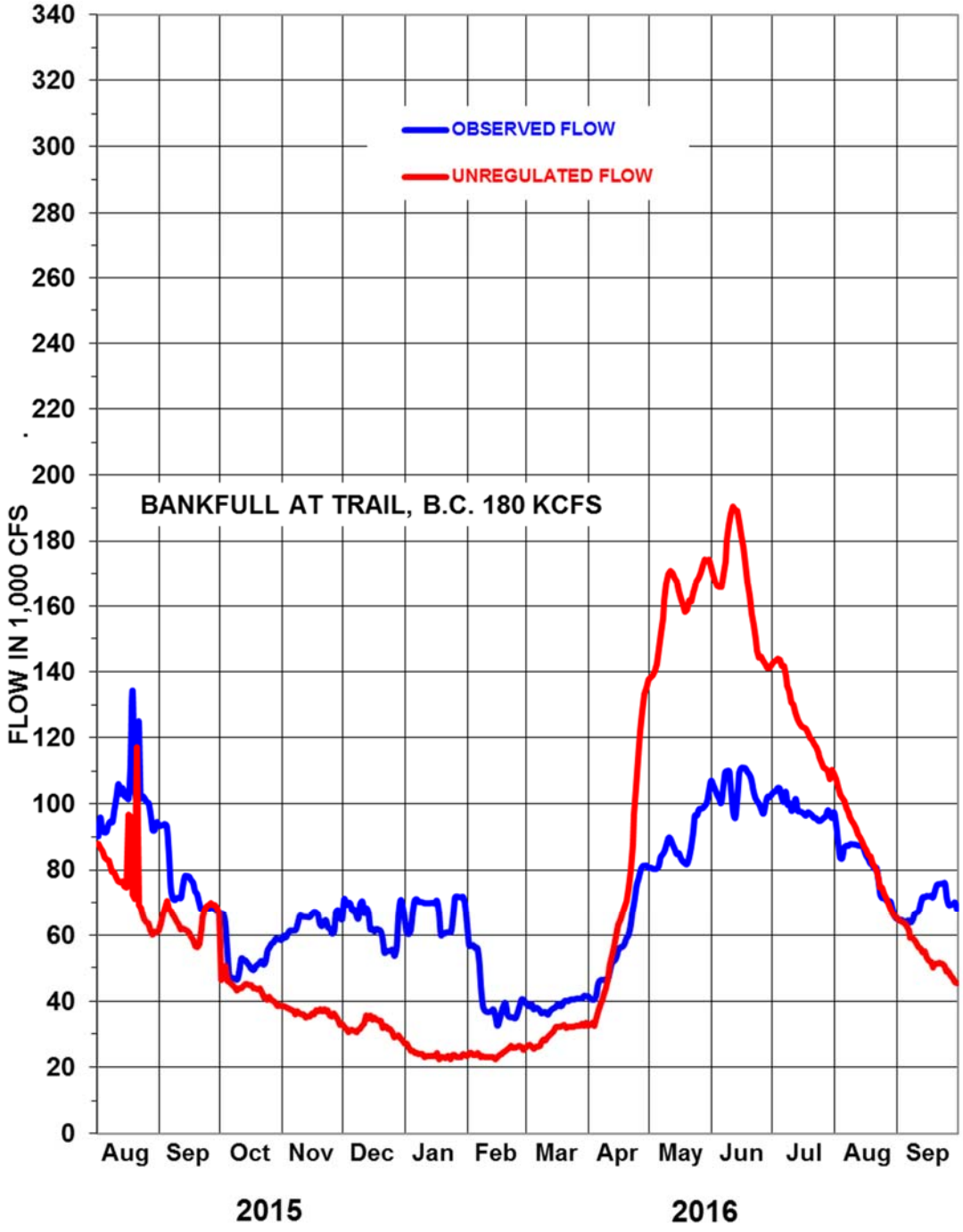
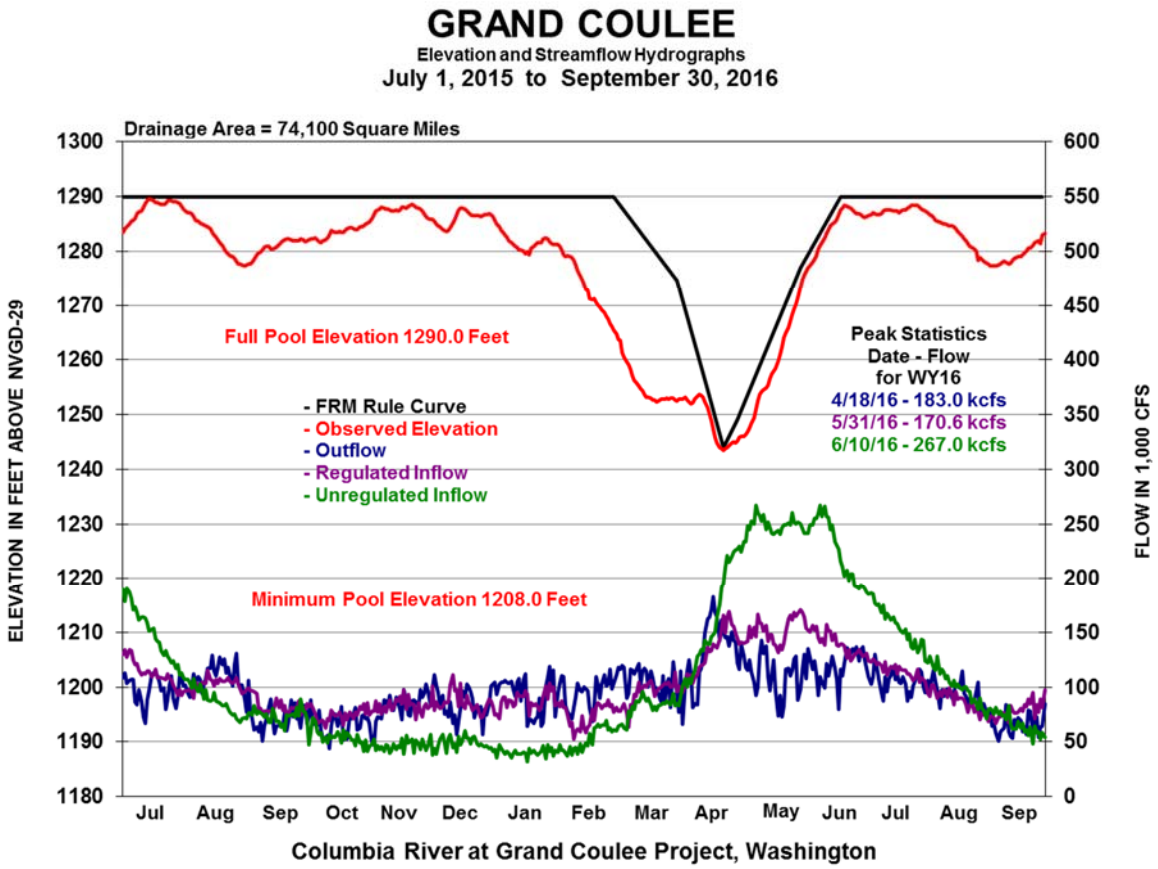


Chart 11: Regulation of Grand Coulee

1 July 2015 – 30 September 2016



NGVD-29 is the National Geodetic Vertical Datum of 1929

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

1 October 2015 – 30 September 2016

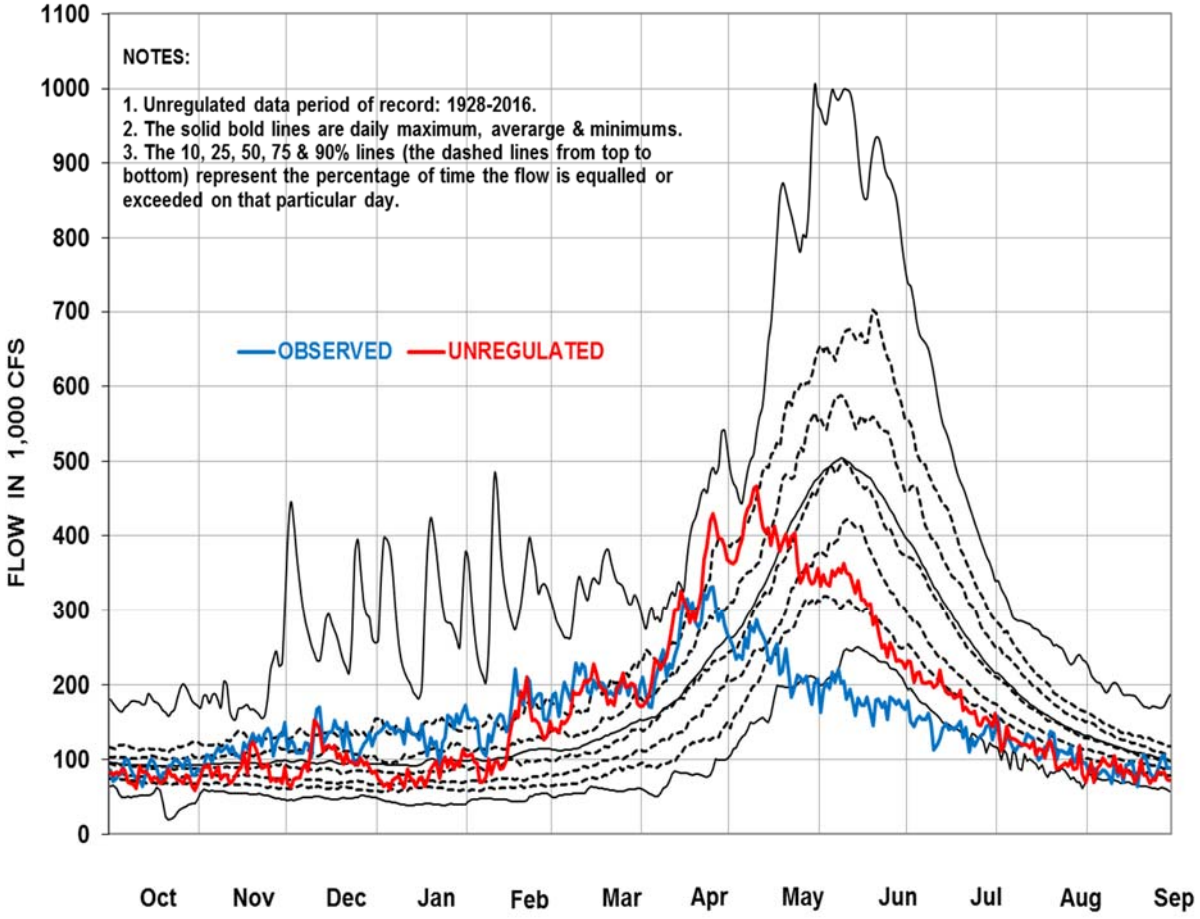


Chart 13: 2016 Columbia River at The Dalles Re-Regulation Plot

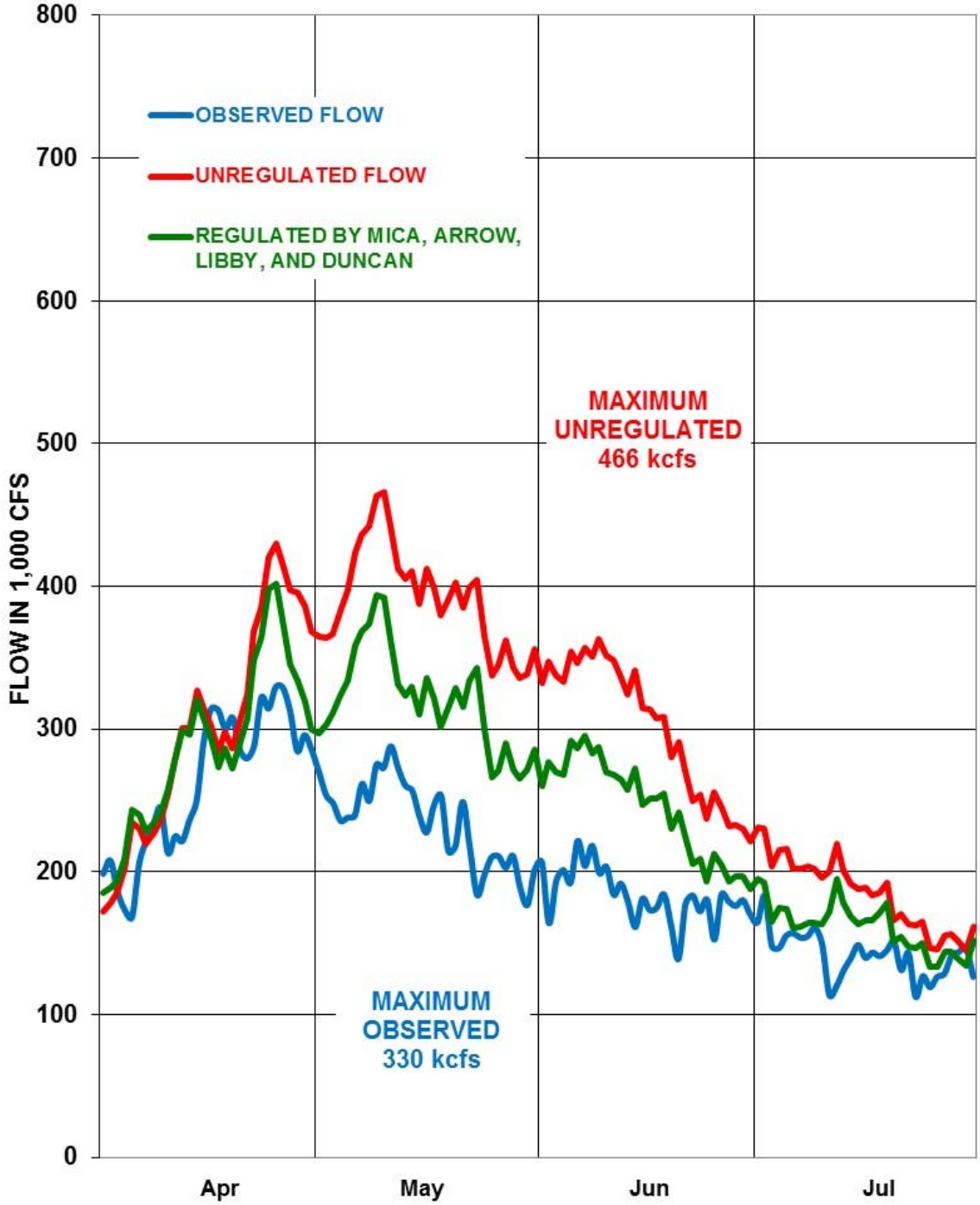
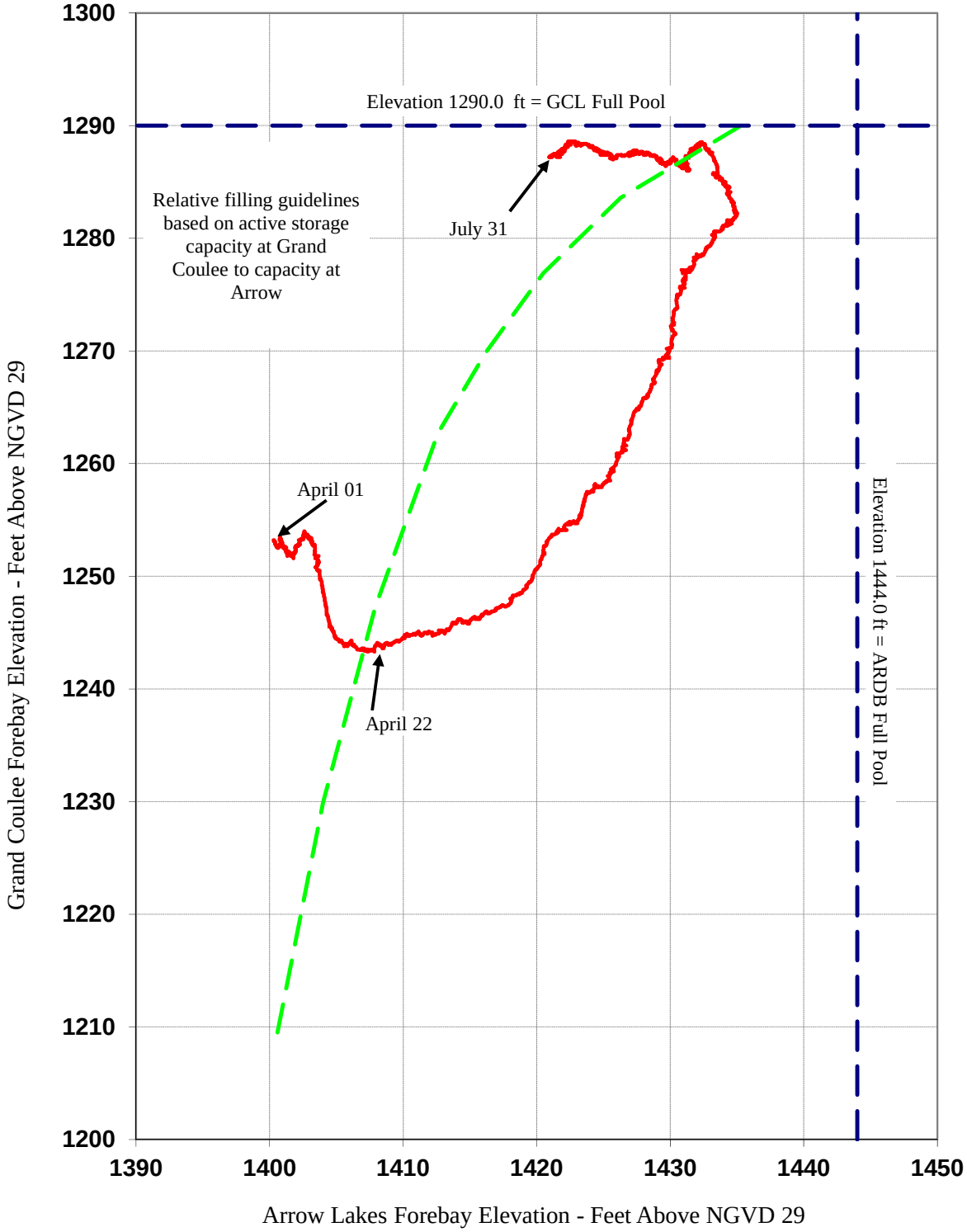


Chart 14: 2016 Relative Filling Keenleyside and Grand Coulee



NGVD-29 is the National Geodetic Vertical Datum of 1929