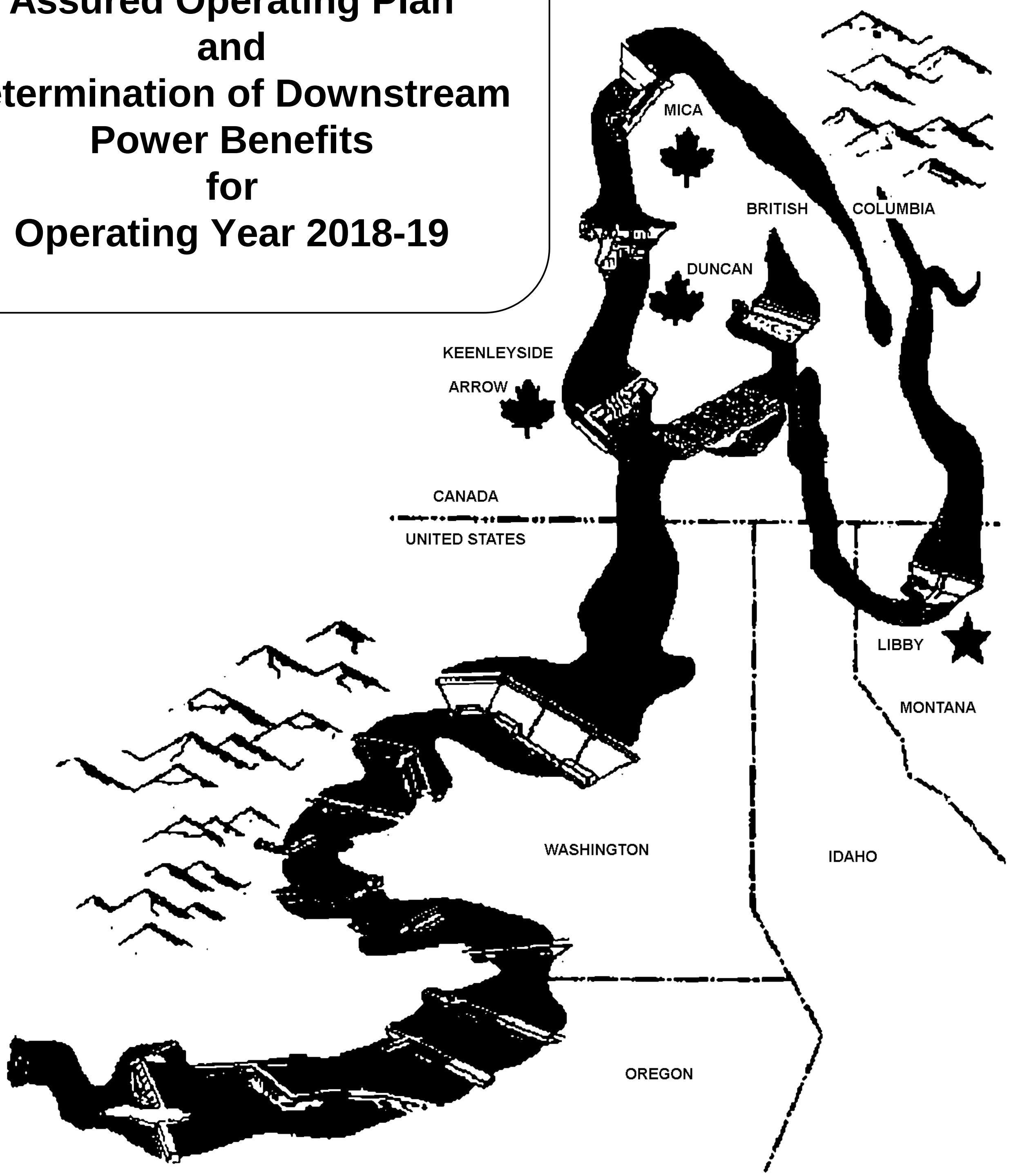
COLUMBIA RIVER TREATY
Assured Operating Plan
and
Determination of Downstream Power Benefits
for
Operating Year 2018-19



Columbia River Treaty Operating Committee

December 2013

COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR OPERATING YEAR 2018-19

The Columbia River Treaty between Canada and the United States of America requires that the Entities agree annually on an assured plan of operation for Canadian Treaty Storage and the resulting downstream power benefits for the sixth succeeding year.

The Entities agree that the attached reports entitled "Columbia River Treaty Hydroelectric Operating Plan: Assured Operating Plan for Operating Year 2018-19" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2018-19," both dated December 2013, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the 2018-19 Operating Year.

In witness thereof, the Entities have caused this Agreement to be executed.

Executed for the Canadian Entity this 10th day of December, 2013.

By: ______________________
Chris K. O'Riley
Chair

Executed for the United States Entity this 4th day of December, 2013.

By: ______________________
Elliot E. Mainzer
Acting Chairman

By: ______________________
Brigadier General John S. Kem
Member

ERRATA for

COLUMBIA RIVER TREATY

DETERMINATION OF DOWNSTREAM POWER BENEFITS

for the ASSURED OPERATING PLAN
for OPERATING YEAR 2015-16

October 2013

The following page shows a correction to the table, Determination of Step I Firm Peak Hydro Loads, published as Table 1B on page 9 of the document, Determination of Downstream Power Benefits (DDPB) for the Assured Operating Plan (AOP) for Operating Year (OY) 2015-16, dated September 2011.

Originally, Table 1B was published with a sizable error on line 2(d). This error, in turn, led to errors on lines 2(k), 5, 7, 9, 10(a) and 10(c).

Because this error was discovered during the development of AOP19, the U.S. and Canadian Entity Operating Committee Chairs determined that posting an errata statement in this AOP 19 document would be appropriate, as well as in the upcoming Detailed Operating Plan for Canadian Storage that will be developed for the period of OY 2015-16.

TABLE 1B
DETERMINATION OF STEP I FIRM PEAK HYDRO LOADS
FOR 2015-16 ASSURED OPERATING PLAN
(MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. Pacific Northwest Area (PNWA) Firm Load														
a) White Book Regional Firm Load	29828	29828	27762	28901	32594	35154	35278	33675	30799	28910	28910	28382	29497	31072
b) Exclude 99% of UPL's Idaho load	-463	-463	-432	-431	-431	-461	-439	-452	-423	-400	-400	-446	-517	-570
c) Adj.for Federal Peak Diversity 1/	-445	-478	-507	-320	-293	-507	-302	-306	-349	-467	-481	-476	-471	-385
d) Updates to Coulee pumping forec.	321	302	293	387	257	337	170	189	325	183	155	257	290	293
e) …Total PNWA Firm Loads	**29240**	**29188**	**27116**	**28537**	**32127**	**34522**	**34707**	**33106**	**30352**	**28226**	**28184**	**27715**	**28799**	**30409**
f) Monthly Load Factors in Percent	75.40	75.39	76.29	72.67	72.04	73.05	72.89	72.40	73.56	75.09	75.38	74.54	74.96	75.16
2. Flows-Out of firm power from PNWA														
a) White Book Exports	2488	2488	2486	2125	1991	1990	1988	1989	1991	2020	2027	1870	2374	2364
b) Remove WB Canadian Entitlement	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350
c) Add estimated Can.Entitle. exported	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367
d) Added export for WB surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Add Seasonal Exch. WB Export	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Add Seasonal Exch. Shape Export	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Thermal Inst. used outside region 2	258	258	279	152	117	10	0	77	55	39	15	140	256	249
h) …Subtotal for Table 2	*2763*	*2763*	*2782*	*2293*	*2125*	*2017*	*2005*	*2082*	*2063*	*2076*	*2059*	*2027*	*2647*	*2630*
i) Remove Plant Sales	-563	-563	-563	-563	-555	-552	-552	-552	-555	-555	-563	-419	-563	-563
j) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75
k) …Total	**2125**	**2125**	**2144**	**1686**	**1525**	**1419**	**1408**	**1485**	**1463**	**1446**	**1422**	**1533**	**2009**	**1992**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations														
a) White Book Imports	-1073	-1073	-1010	-1113	-1438	-1613	-1625	-1593	-1278	-1171	-1171	-1059	-1130	-1206
b) Remove UP&L imports for	542	542	498	498	505	528	498	511	476	451	451	525	630	666
c) Remove Eastern Thermal Instal	309	309	291	423	462	571	581	503	498	486	486	313	279	319
d) Added SeEx for WB Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Added Can.Import for WB deficits	0	-1367	-1367	0	0	-1367	-1367	-1367	-1367	0	0	0	0	-1367
f) Added Calif.Import for WB deficits	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Added Seas.Exch. for Aop hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	45	45	75	75	75	75	75
i) …Total	**-146**	**-1513**	**-1513**	**-147**	**-427**	**-1837**	**-1868**	**-1901**	**-1626**	**-159**	**-159**	**-147**	**-146**	**-1513**
4. PNWA Non-Step I Hydro and Non-thermal Resources														
a) Hydro Independents (1932)	-1569	-1554	-1582	-1342	-1584	-1497	-1568	-1395	-1789	-1775	-1818	-1968	-2005	-1749
b) Non-Step I Coord. Hydro (1932)	-1821	-1980	-2006	-2075	-2142	-2114	-2019	-1867	-1752	-1711	-1811	-2012	-2361	-2440
c) WB Regional Hydro NUGs	-371	-369	-297	-214	-156	-143	-135	-146	-183	-297	-306	-433	-454	-444
d) WB Renewable NUGs	-76	-76	-76	-76	-76	-76	-76	-76	-76	-76	-76	-76	-76	-76
e) WB Renewables	-29	-29	-29	-29	-29	-29	-29	-29	-29	-29	-29	-29	-29	-29
f) …. Total (1932)	**-3866**	**-4008**	**-3990**	**-3737**	**-3987**	**-3860**	**-3828**	**-3513**	**-3829**	**-3888**	**-4040**	**-4519**	**-4925**	**-4738**
5. Step I System Load 3/ (1932)	**27353**	**25791**	**23757**	**26338**	**29238**	**30245**	**30419**	**29177**	**26360**	**25625**	**25407**	**24582**	**25737**	**26149**
6. Coordinated Thermal Installations														
a) Columbia Generating Station (CGS)	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	565	565	1140
b) Generic Thermal Installations	10738	10738	10794	10889	10953	10997	11007	10978	10468	9955	9489	8581	10125	10741
c) ...Total	**11878**	**11878**	**11934**	**12029**	**12093**	**12137**	**12147**	**12118**	**11608**	**11095**	**10629**	**9146**	**10690**	**11881**
7. Step I Hydro Resc. Needed (1932) 4/	**25798**	**23865**	**21569**	**23492**	**26169**	**26376**	**26009**	**25152**	**22918**	**22814**	**22830**	**23405**	**23381**	**24125**
8. Step I Resource Adjustments														
a) Hydro Maintenance 5/	-4595	-4032	-3787	-3208	-2935	-2037	-1561	-2286	-2626	-2751	-2483	-2360	-2202	-3720
b) Transmission System Losses 6/	-1196	-1271	-1273	-1248	-1279	-1344	-1334	-1258	-1195	-1156	-1164	-1172	-1281	-1316
c) Reserves (assume 11%) 7/	-4532	-4648	-4685	-4727	-4811	-4886	-4842	-4550	-4344	-4376	-4405	-4437	-4852	-4819
d) ...Total maint., losses, & reserves	#####	-9952	-9745	-9183	-9024	-8268	-7737	-8094	-8166	-8283	-8052	-7969	-8334	-9856
e) Hydro maint. as %reg. hydro cap.=	15.3%	13.3%	12.4%	10.5%	9.6%	6.7%	5.3%	8.2%	9.8%	10.0%	8.9%	8.1%	7.2%	12.0%
f) Peak Resv. as % resources	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
9. Required Step I Resources	**27353**	**25791**	**23757**	**26338**	**29238**	**30245**	**30419**	**29177**	**26360**	**25625**	**25407**	**24582**	**25737**	**26149**
10. Coordinated Hydro load and Surplus/Deficit (1932)														
a) Coordinated Hydro Load (1932) 8/	27619	25844	23574	25568	28311	28490	28029	27019	24670	24525	24640	25417	25742	26564
b) Actual Coord. Hydro Gen (1932) 9/	30052	30403	30451	30416	30590	30463	29605	28019	26684	27550	27864	29035	30694	30914
c) ...Surplus/Deficit (1932)	2433	4559	6877	4848	2279	1973	1576	1000	2014	3025	3224	3618	4952	4350

Notes:

1/ Federal peak diversity is a reduction in peak load due to peak loads not all being coincidental.

2/ Export or import to balance difference between excluded thermal imports and generic thermal installation.

3/ Total Step I Firm Peak Load is the sum of lines 1(e) + 2(k) + 3(i) + 4(f)

4/ Step I hydro resources needed to meet the load = line 5 - line 6(c) - line 8(d). Actual resource capability is higher. Used 1932 because has lowest surplus.

5/ From WB, based on 5-year PNCA average as a MW reduction from installed capacity. May need to revise next year as a reduction from 1937 capability.

6/ Transmission losses are 3.25% of all resources including imports, net of reserves and maintenance.

7/ Reserves are 11% of resources, i.e. 4(f), 6(c), 10(b) - 8(a)

8/ Lines 4b and 7

9/ System Instantaneous Peak (1932)

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 2018-19

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HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2018-19

December 2013

1. Introduction

The “Treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin” (Treaty), dated 17 January 1961, requires that each year the Entities designated by the two governments will formulate and carry out operating arrangements necessary to implement the Treaty and will agree on an Assured Operating Plan (AOP) for the Treaty storage in Canada (Canadian Treaty Storage) and resulting downstream power benefits for the sixth succeeding operating year. This AOP for operating year 2018-19 (AOP19) provides the Entities with an operating plan for Canadian Treaty Storage and information for planning the power systems that are dependent on or coordinated with the operation of the Canadian Treaty Storage projects.

2. Development of the Assured Operating Plan

a) Procedures

This AOP was prepared in accordance with the Treaty, the “Protocol - Annex to Exchange of Notes, Dated January 22, 1964 Between the Governments of Canada and the United States Regarding the Columbia River Treaty” (Protocol), and the following Entity Agreements:

- The Entity Agreements, signed 28 July and 12 August 1988, on “Principles for the Preparation of the AOP and Determination of Downstream Power Benefit (DDPB) Studies” and “Changes to Procedures for the Preparation of the AOP and DDPB Studies” (1988 Entity Agreements);

- The “Columbia River Treaty Entity Agreement on Resolving the Dispute on Critical Period Determination, the Capacity Entitlement, for the 1998-99, 1999-00, and 2000-01 AOP/DDPBs, and Operating Procedures for the 2001-02 and Future AOPs,” signed 29 August 1996 (29 August 1996 Entity Agreement); and

- Except for the changes noted below, the "Columbia River Treaty Entity Agreement on the Principles and Procedures for Preparing and Implementing Hydroelectric Operating Plans For Operation of Canadian Treaty Storage" (POP), dated October 2003 and signed 16 December 2003, including the September 2011 update to Appendix 1 - Refill Curves; the November 2004 addition of Appendix 6 - Streamline Procedures; the addition of Appendix 7 – Table of Median Flows based on the 2010 Level Modified Streamflows; and the September 2007 addition of Appendix 8 concerning Water Supply Forecasts along with the

February 2012 revision of Appendix 8, Table 1, concerning the Summary of Errors and Hedges.

Special terms used in this document, but not defined herein, have the meanings defined in the Treaty, Protocol, or the above Entity Agreements. The POP is based on criteria contained in Annex A and Annex B of the Treaty, the Protocol, and the Columbia River Treaty Flood Control Operating Plan (FCOP), dated May 2003.

For the AOP19, the Entities have agreed to use all three streamline procedures defined in Appendix 6 of the POP. These streamline procedures include "Forecasting Loads and Resources" for determining the thermal installations, as described in Subsection 7(d) of this document, the "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage" based on the AOP18 Joint Optimum Step I system regulation study, as explained in Subsection 2(b) of this document, and the "Monthly Hydro Energy Reshaping for Step II and III 30-year System Regulation Studies" for determining the energy entitlement, as described in Subsection 7(f) of the accompanying document, Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2018-19 (DDPB19).

In addition, the Entities have agreed to add to or modify certain procedures defined in POP as follows:

- Allocate available uncommitted PNWA resources and available uncommitted imports from Canada and California to balance the White Book (WB) firm load/resource deficit, as was done since the AOP/DDPB13, as described in Subsections 7(b) and 7(d), and include the allocated Canadian import into the load/resource balance

- Exclude seasonal exchanges for balancing WB loads and resources (the same as was done since AOP16);

- Shape generic thermal installations based on the full amount of WB large thermal, co-generation and combustion turbines and 30% of unreported CT energy capability that are estimated to be needed to meet the WB load, as described in Subsection 7(d); and

In accordance with Protocol VII(2), this AOP provides a reservoir-balance relationship for each month for the whole of the Canadian Treaty Storage. This relationship is determined from the following:

- The Critical Rule Curves (CRCs), Upper Rule Curves (URCs), and the related rule curves and data for each project used to compute the individual project Operating Rule Curves (ORCs);

- Operating rules and criteria for operation of the Canadian Treaty Storage in accordance with the principles contained in the above references; and

- The supporting data and model used to simulate the 30-year operation for the Step I Joint Optimum (AOP18-41) system regulation study[1].

This AOP includes both metric (International Standard) and English units[2]. The system regulation studies and supporting data were based on English units. The metric units are approximations derived by rounding conversions from English units. Metric values are displayed with either one or two decimal places to assure consistency with English units and do not imply that level of precision. The inclusion of metric units complies with USA Federal statutory requirements. Tables referred to in the text are in English units. Metric tables use the same numbering system as the English tables with the letter "M" after the table number.

b) System Regulation Studies

This AOP was prepared in accordance with Annex A, paragraph 7, of the Treaty, which requires Canadian Treaty Storage operation for joint optimum power generation in both Canada and the USA. Downstream power benefits were computed with the Canadian Treaty Storage operation based on the same criteria for joint optimum power generation used in the Step I study.

Step I system regulation studies for the AOP19 are based on 2018-19 operating year estimated loads and resources in the USA PNWA including estimated flows of power from and to adjacent areas and hydro resources in the Columbia River Basin in British Columbia. In accordance with the Streamline Procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage", the Entities have agreed to add seasonal exchange imports and exports to adjust the Step I system regulated hydro energy load to be the same as in the AOP18. With the same regulated hydro energy load and no change in hydro system capability, the AOP18 Step I system regulation study can serve as the basis for the AOP19.

In accordance with Protocol VIII, the AOP19 is based on a 30-year stream flow period and the Entities have agreed to use an operating year of 1 August through 31 July. The studies used historical flows for the period August 1928 through July 1958, modified by estimated irrigation depletions for the 2010 level[3] and including updated estimates of Grand Coulee net pumping requirements.

The CRCs were determined from critical period studies of optimum power generation in both Canada and the USA. The study indicated a continuous 42.5 calendar-month critical period for the USA Step I system resulting from flows during the period from 16 August 1928 through 29 February 1932. With the exception of Brownlee and Dworshak, it was assumed that all reservoirs, both in the USA and Canada, were full at the beginning of the critical period except where minimum release requirements made this impossible.

The Corps of Engineers has transitioned to new terminology, from "Flood Control" to "Flood Risk Management" (FRM). Historic documents that use the term "flood control" will not be changed. The Flood Risk Management operation at Canadian projects was based on individual project flood risk criteria instead of a composite curve. The Canadian Entity selected a 5.03/4.44 cubic kilometer (km^3) (4.08/3.6 million acre-feet (Maf)) Mica/Arrow flood risk allocation in accordance with Section 6 of the FCOP. Flood Risk Management and Variable Refill Curves are based on historical inflow volumes. Although only 19.12 km^3 (15.5 Maf) of usable storage is committed for power operation purposes under the Treaty, the FCOP provides for the full draft of the total 25.29 km^3 (20.5 Maf) of usable storage for on-call flood risk management purposes. Flood Risk Management Rule Curves are implemented in the system regulation studies as upper rule curves.

c) Evaluation of the Joint Optimum Study

In accordance with Subsections 3.2.A and 3.3.A(3) of the POP, the changes in Canadian Treaty Storage operation for an optimum power generation at-site in Canada and downstream in Canada and the USA (Joint Optimum), compared to an operation for optimum power only in the USA (USA Optimum), were evaluated as required by Annex A, paragraph 7 of the Treaty using the two criteria described below:

(1) Determination of Optimum Generation in Canada and the USA

To determine whether optimum power generation in both Canada and the USA was achieved in the system regulation studies, the annual firm energy capability, dependable peaking capability, and average annual usable secondary energy were computed for both the Canadian and USA systems.

In order to measure optimum power generation for the AOP19, the Columbia River Treaty Operating Committee agreed that the three quantities would be assigned the following relative values:

Quantity	Relative Value
Annual firm energy capability (average megawatts (aMW))	3
Dependable peaking capability (MW)	1
Average annual usable secondary energy (aMW)	2

For the AOP19, in accordance with the second streamline procedure (as described in Subsection 2(b)), these quantities were based on the AOP18 studies. It should also be noted that the period for the dependable peaking capability (i.e. the period with the least surplus firm peak capability over the thirty water years) changed from 15 August 1931 (in AOP18) to January 1932 (in AOP19) due to changes in the peak load shape.

The sum of the three weighted quantities showed a net gain in the Joint Optimum Study compared to the USA Optimum Study. The Entities agree that this result is in accordance with Subsection 3.2.A of the POP. The results of these calculations are shown in Table 2.

(2) Maximum Permitted Reduction in Downstream Power Benefits

Annex A, paragraph 7 of the Treaty defines the limits to any reduction in the downstream power benefits in the USA resulting from a change in Canadian Treaty Storage operation to achieve a joint optimum operation.

In accordance with the third streamline procedure (as described in the DDPB19, Subsection 7(f)), and using the re-shaped DDPB18 storage operation for the optimum generation in both Canada and the USA, there was a 1.3 aMW increase in the Canadian Entitlement for average annual usable energy, as compared to the re-shaped USA optimum operation. There was no change in the dependable capacity compared to the operation for optimum generation in the USA alone. (See Table 5 of DDPB19, columns A and B.)

Since there is no reduction in entitlement, the Entities have determined in Section 4 of the DDPB19 that the calculation of maximum permitted reduction in downstream power benefits is not necessary.

3. Rule Curves

The operation of Canadian Treaty Storage during the 2018-19 Operating Year shall be guided by the ORCs and CRCs for the whole of Canadian Treaty Storage, Flood Risk Management Curves for the individual projects, and project operating criteria for Mica and Arrow. The ORCs and CRCs are first determined for the individual Canadian projects and then summed to yield the Composite ORC for the whole of Canadian Treaty Storage, in accordance with paragraph VII-(2) of the Protocol. The ORCs are derived from the various curves described below.

a) Critical Rule Curves

The CRC is defined by the end-of-period storage content of Canadian Treaty Storage during the critical period. It is used to determine proportional draft below the ORCs as defined in Subsection 4(b) of this document. Generally, CRCs are adjusted for crossovers by the hydro regulation model as defined in Section 2.3.A of the POP. CRC crossovers occur when the second, third, or fourth year CRCs are higher than any of the lower numbered CRCs. Past practice was for the hydro regulation model to lower the storage amounts in the higher numbered CRCs at all projects as needed to eliminate the crossover. For the Canadian Treaty projects, this adjustment is applied only if the sum of Mica + Arrow + Duncan Treaty storage has a composite CRC crossover. The adjustment is made to Arrow first unless or until Arrow is empty, then the adjustment is made to Duncan. The CRCs for Duncan, Arrow, Mica, and the Composite CRCs for the whole of Canadian Treaty Storage are tabulated in Table 3.

b) Refill Curves

There are two types of refill curves, Assured Refill Curves (ARCs) and Variable Refill Curves (VRCs), which are discussed in the following subsections. Tabulations of the ARCs and VRCs, and supporting data used in determining the ARCs and VRCs for Mica, Arrow, and Duncan are provided in Tables 4, 5, and 6, respectively. Under the second streamline procedure, all distribution factors, forecast errors, Power Discharge Requirements (PDRs), and Operating Rule Curve Lower Limits (ORCLLs) are the same as used in the AOP18.

(1) Assured Refill Curves

The ARCs indicate the minimum August through June end-of-period storage contents required to meet firm load and refill the Coordinated System storage by 31 July, based on the 1930-31 inflows. The upstream storage requirements and the PDR are determined in accordance with Section 2.3.B and Appendix 1 as modified in the POP. The 1930-31 inflows are the second lowest January through July unregulated streamflows at The Dalles, Oregon, during the 30-year (1928-58) stream flow period, which has approximately a 95% probability of exceedance.

(2) Variable Refill Curves

The VRCs indicate the minimum January through June end-of-period storage contents required to refill the Coordinated System storage by 31 July based on the 95% confidence forecasted inflow volume. The upstream storage refill requirements and PDRs are determined in accordance with Section 2.3.B and Appendix 1 as modified in the POP. In the system regulation studies, historical volume inflows, adjusted for the 95% confidence forecast error, were used instead of forecast inflows. The PDRs are a function of the unregulated January through July runoff volume at The Dalles, Oregon. In those years when the January through July runoff volume at The Dalles is between 98.68 km^3 (80 Maf) and 135.69 km^3 (110 Maf), the PDRs are interpolated linearly between the values shown in Tables 4-6. In those years when the January through July runoff volume at The Dalles is less than 98.68 km^3 (80 Maf), or greater than 135.69 km^3 (110 Maf), the PDR values for 98.68 km^3 and 135.69 km^3 (80 Maf and 110 Maf), respectively, are used. For AOP19, as was used since AOP12, the VRC Lower Limit (VRCLL) was applied as a set rule curve lower limit for Grand Coulee's VRC only.

Tables 4-6 illustrate the range of VRCs for Mica, Arrow, and Duncan for the 30-year stream flow period. In actual operation in 2018-19, the PDRs and VRCLLs will be based on the forecast of unregulated runoff at The Dalles.

c) Operating Rule Curve Lower Limits

The ORCLLs indicate the minimum 31 January through 15 April end-of-period storage contents that must be maintained to protect the ability of the system to meet firm load during the period 1 January through 30 April. The ORCLLs protect the system's ability to meet firm load in the event that the VRCs permit storage to be emptied and sufficient natural flow is not available to carry the load prior to the start of the freshet. Such rule curves shall limit the ORC to be no lower than the ORCLLs. The ORCLLs are developed for 1936-37 water conditions which include the lowest January through April unregulated streamflows at The Dalles during the 30-year stream flow period. The ORCLLs for Mica, Arrow, and Duncan are shown in Tables 4, 5, and 6, respectively.

d) Upper Rule Curves (Flood Risk Management)

The URCs indicate the maximum end-of-period storage contents to which each individual Canadian Treaty Storage project shall be evacuated for Flood Risk Management. The URCs used in the studies were based upon Flood Control Storage Reservation Diagrams contained in the FCOP and analysis of system flood risk simulations. URCs for Mica, Arrow, and Duncan for the 30-year stream flow period are shown in Tables 7, 8, and 9, respectively. Tables 7 and 8 reflect an agreed transfer of flood management space in Mica and Arrow to maximum drafts of 5.03 km^3 and 4.44 km^3 (4.08 Maf and 3.6 Maf), respectively. In actual operation for 2018-19, the URCs will be computed as outlined in the FCOP using the latest forecast of runoff available at that time.

e) Operating Rule Curves

The ORCs define the normal limit of storage draft to produce secondary energy and provide a high probability of refilling the reservoirs. In general, the Operating Plan does not permit serving secondary loads at the risk of failing to refill storage and thereby jeopardizing the firm load carrying capability of the USA or Canadian systems during subsequent years.

During the period 1 August through 31 December, the ORC is defined as the CRC for the first year of the critical period (CRC1) or the ARC, whichever is higher. During the period 1 January through 31 July, the ORC is defined as the higher of the CRC1 and the ARC, unless the VRC (limited by the VRCLL) is lower, then the VRC defines the ORC. During the period 1 January through 15 April, the ORC will not be lower than the ORCLL. The ORC shall be less than or equal to the URC at each individual project in all periods. The composite ORCs for the whole of Canadian Treaty Storage for the 30-year streamflow period are included in Table 10 to illustrate the probable future range of these curves based on historical water conditions.

4. Operating Rules

As described in Subsection 2(b) of this document, the AOP19 system regulation study is based on the AOP18-41 system regulation study. The storage operation results for the whole of Canadian Treaty Storage for the 30-year streamflow period are shown in Table 11. The study contains the agreed-upon ORCs and CRCs, and operating procedures and constraints, such as maximum and minimum project elevations, discharges, and draft rates. These constraints are included as part of this operating plan and are listed in Appendix A of this document.

The following rules and other operating criteria included in the AOP18-41 system regulation study will apply to the operation of Canadian Treaty Storage during the 2018-19 Operating Year, subject to the provisions under Section 5 of this document.

a) Operation at or above ORC

The whole of Canadian Treaty Storage will be drafted to its ORC as required to produce optimum generation in Canada and the USA in accordance with Annex A, paragraph 7, of the Treaty, subject to project physical characteristics and operating constraints.

b) Operation below ORC

The whole of Canadian Treaty Storage will be drafted below its ORC as required to produce optimum power generation, to the extent that a system regulation study determines that proportional draft below the ORC is required to produce the hydro firm energy load carrying capability (FELCC) of the USA system. FELCC is determined by the applicable Critical Period regulation study. Proportional draft between rule curves will be determined as described in Section 2.4.C of the POP.

c) Canadian Treaty Project Operating Criteria

Mica and Arrow reservoirs will be operated in accordance with project operating criteria listed in Tables 1 and 1.1, respectively, so as to optimize generation at Mica, Revelstoke, and Arrow, and downstream in the USA. Under these operating criteria, outflows will be increased as required to avoid storage above the URC at each reservoir.

(1) Mica Project Operating Criteria

In general, the Mica operation in each period is either a target flow or target content, as listed in Table 1 and is determined by Arrow's storage content at the end of the previous period. In the event that Mica's operation to the Table 1 operating criteria results in more or less than the project's share of draft from the whole of Canadian Treaty Storage as described in Subsections 4(a) or 4(b) above, compensating changes will be made at Arrow to the extent possible.

Mica storage releases in excess of 8.63 km^3 (7.0 Maf) that are required to maintain the Mica outflows specified under this plan will be retained in the Arrow reservoir, subject to flood risk management and other project operating criteria at Arrow. The total combined storage draft from Mica and Arrow will not exceed 17.39 km^3 (14.1 Maf), unless flood risk management or minimum flow criteria will not permit the excess Mica storage releases to be retained at Arrow. Based on this AOP, the probability of a combined Mica + Arrow storage release in excess of 17.39 km^3 (14.1 Maf) occurring has been judged to be negligible; however, in actual operations, should Treaty specified constraints require combined Mica + Arrow storage draft in excess of 17.39 km^3 (14.1 Maf), it is mutually agreed for the sole purpose of this AOP that such releases may occur. If such a release should occur, the target Mica operation will remain as specified in Table 1, and the excess release will be returned as soon as the operating criteria permit.

The adoption of the above described procedure for addressing total combined storage draft from Mica and Arrow in this AOP19 is not intended to set a precedent for future AOPs and is subject to change in future AOPs.

(2) Arrow Project Operating Criteria (APOC)

In general, Arrow reservoir will be operated to provide the balance of the required Canadian Treaty Storage as described in Subsections 4(a) or 4(b) above, subject to physical and operating constraints. These constraints include, but are not limited to, the URC, rate-of-draft and minimum flows limits, and the Arrow Project Operating Criteria (APOC).

The APOC are shown in Table 1.1(a) and consists of maximum storage limits, maximum outflow limits and minimum outflow limits at Arrow. The maximum storage limits apply from February to June depending on the forecast for The Dalles residual unregulated runoff for the current month through July. The maximum and minimum outflow limits apply under all water conditions, subject to flood risk management requirements and a maximum combined draft of 17.39 km^3 (14.1 Maf) at Mica + Arrow, respectively. In no circumstance shall the minimum outflow be reduced below the Treaty specified minimum of 142 m^3/s (5,000 cfs).

Implementation of the APOC storage limits in the Detailed Operating Plan will use the distribution factors shown in Table 1.1(c). These distribution factors are multiplied by the current month through July forecast volumes at The Dalles, to calculate future month through July volume forecasts. The resulting residual month-July volumes are then used to determine the maximum storage levels from the criteria provided in Table 1.1(a). To assist implementation of this procedure, an example is shown at the bottom of Table 1.1(c).

d) <u>Other Canadian Project Operation</u>

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta are included in the AOP19 as run-of-river projects. Generation at Arrow is modeled in the studies. Corra Linn and Kootenay Canal are included and operated in accordance with criteria utilized in the AOP18.

5. Preparation of the Detailed Operating Plan

The Entities have to this date agreed that each year a Detailed Operating Plan (DOP) will be prepared for the immediately succeeding operating year. Such DOPs are made under authority of Article XIV.2 of the Columbia River Treaty, which states in part:

> ". . . the powers and the duties of the entities include: . . .
>
> “(k) preparation and implementation of detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under the plans referred to in Annexes A and B."

The 2018-19 DOP (DOP19) will reflect the latest available load, resource, and other pertinent data to the extent the Entities agree that this data should be included in the plan. The data and criteria contained herein may be reviewed and updated as agreed by the Entities to form the basis for a DOP19. Failing agreement on updating the data and/or criteria, the DOP19 for Canadian Treaty Storage shall include the rule curves, Mica and Arrow operating criteria, and other data and criteria provided in this AOP. Actual operation of Canadian Treaty Storage during the 2018-19 Operating Year shall be guided by the DOP19.

In AOP studies the values used to define the various rule curves are period-end values only. In actual operation, it is necessary to operate in such a manner during the course of each period that these period-end values can be achieved in accordance with the operating rules. Due to the normal variation of power load and streamflow during any period, straight-line interpolation between the period-end points should not be assumed. During the storage drawdown season, Canadian Treaty Storage should not be drafted below its period-end point at any time during the period unless it can be conservatively demonstrated that sufficient inflow is available, in excess of the minimum outflow required to serve power demand, to refill the reservoir to its end-of-period value as required.

During the storage evacuation and refill season, operation will be consistent with the FCOP. When refill of Canadian Treaty Storage is being guided by Flood Risk Management Refill Curves, such curves will be computed on a day-by-day basis using the residual volume-of-inflow forecasts depleted by the volume required for minimum outflow, unless higher flows are required to meet firm load, for each day through the end of the refill season.

6. Canadian Entitlement

The amount of Canadian Entitlement is defined in the companion document "Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2018-19."

The Treaty specifies return of the Canadian Entitlement at a point near Oliver, British Columbia, unless otherwise agreed by the Entities. Because no cross-border transmission exists near Oliver, the Entities completed an agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024, dated 29 March 1999[4]. This Agreement covers the full 1 August 2018 through 31 July 2019 period covered by this AOP, and includes transmission losses and scheduling guidelines for delivery of the Canadian Entitlement.

7. Summary of Changes Compared to the 2017-18 AOP and Notable Assumptions

Data from the recent AOPs are compared and summarized in Table 12. An explanation of the more important changes and notable assumptions follows.

a) Pacific Northwest Area (PNWA) Firm Load

Loads for the AOP19 are based on Bonneville Power Administration's (BPA) October 2012 White Book (WB12)[5] expected load forecast. The WB12 forecast for the 2018-19 regional firm load is 23,548 annual aMW, which is 275 aMW higher than the AOP18. There were minor changes to the Idaho portion of the Utah Power & Light load and to the Coulee pumping requirements, leading to an increase in the net PNWA firm load by 270 annual aMW from the AOP18 to AOP19.

The average critical period load factor increased from 74.60% in AOP18 to 75.08% in AOP19. This was mainly due to changes in the energy and peak load forecast.

b) Flows of Power at Points of Interconnection

The Step I System Load includes the net effect of flows of power at points of interconnection which are all imports and exports, except those classified as thermal installations, plant sales, and flow-through-transfers.

- For the AOP19, the estimate of the amount of Canadian Entitlement energy and other uncommitted imports that would be assumed to serve load in the PNWA were based on a similar procedure being used since AOP13, except that since AOP16, the use of added seasonal exchanges to balance firm WB loads and resources has been eliminated. This procedure assumes all of the Canadian Entitlement is returned to Canada, but is then available as an uncommitted import for the PNWA. The procedure determines the WB12 firm energy deficit without uncommitted thermal resources and then uses an allocation procedure of uncommitted resources to eliminate the deficit. The first step eliminates monthly deficits by proportionally allocating uncommitted PNWA resources (without unreported CT capability) and Canadian imports based on their availability. For the AOP19, this procedure resulted in 36% (171 annual aMW) of the available Canadian import being used for serving PNWA load. The allocated amount of uncommitted PNWA resources (without unreported CT capability) is used in the determination of the shape of the generic thermal installation, as discussed in Subsection 7(d). Any remaining deficits are then allocated based on the proportion of available unreported CT capability and assumed available California imports. The resulting amount of allocated imports are included in the Step I load/resource balance. Compared to AOP18, this procedure results in a 41 annual aMW increase in Entitlement energy serving load in the U.S.
- The estimated Canadian Entitlement included in export loads was 470 annual aMW of energy and 1295 MW of capacity. The amount computed for the DDPB19 is 472.5 annual aMW of energy and 1284.0 MW of capacity. Iterative studies to update the Canadian Entitlement assumed in the load estimate (see DDPB Table 1) were not performed because the effect on the amount of thermal installations would not noticeably impact the results of the studies.
- For the AOP19, as was the case since AOP15, a seasonal exchange to reshape the residual hydro load to reflect differences between AOP and WB hydro capabilities was not used. In addition, as was the case since AOP16, the AOP19 did not use seasonal exchanges to balance the firm WB loads and resources. However, in accordance with the Streamline Procedure “Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage” and as described in Subsection 2(b), a seasonal exchange was added to the AOP19 to adjust the Step I system regulated hydro load to be the same as the AOP18.
- Compared to the AOP18, power flows-out (exports that are mostly to the southwest but also include the Entitlement) increased by 69 annual aMW, and power flows-in (imports) increased by 196 annual aMW.
- The difference in total exports can be accounted for due to the net effect of a large increase in WB exports and the use of a Seasonal Exchange to match the AOP19 Step I system regulated hydro load with that from the AOP18 (second

streamline procedure), offset by a large decrease in plant sales as well as a reduction in exported thermal.

- The difference in total imports can be accounted for due primarily to the use of Seasonal Exchanges to match the AOP19 Step I system regulated hydro load with that from the AOP18 (second streamline procedure) and, to a lesser extent, with the increased use of Canadian Imports for WB deficits.

c) Non-Step I Hydro and Other Non-Thermal Resources

The Step I System Load is reduced by hydro-independent generation, non-Step I coordinated hydro, and miscellaneous non-thermal resources. For the AOP19, these resources have increased by 165 annual aMW over the AOP18. This is primarily due to an increase of renewables in AOP19.

Firm wind is included in AOP19 resources from the WB12, as in AOP18. In the WB12, firm wind is the monthly wind generation that occurred in the operating year with the lowest total PNWA wind generation.

d) Thermal Installations

Because of increasing difficulty in forecasting Thermal Installations, the Entities again used the Streamline Procedure for “Loads and Resources” for determining Thermal Installations, as used since AOP07. The procedure includes the Columbia Generating Station (CGS) plus one generic Thermal Installation, sized as needed to balance loads and resources in the critical period. In this AOP, an average of the two year (2017-18 and 2018-19) maintenance cycle at CGS was used.

For the AOP19, as was the case since AOP16, it was agreed that the coordinated thermal installations used to determine the shape of the generic thermal installation for the AOP load and resource balance are the full amount of WB12 large thermal, co-generation, and combustion turbines and 30% of unreported CT energy capability that are estimated to be needed to meet the WB12 load.

The total thermal installations decreased by 22 annual aMW from AOP18 to AOP19, as shown in DDPB19, Subsection 7(b), due to a combination of all changes in loads and resources as explained above. However, changes in thermal maintenance resulted in decreased thermal generation September-November and February-April, and increased generation May-July.

e) Hydro Project Modified Streamflows

The unregulated base streamflows used in the system regulation studies were the same as those used in the AOP18 studies, which were based on the 2010 Modified Streamflow update, published by BPA in August 2011. Modified Streamflows are determined from historic observed streamflows, adjusted to remove the historic storage regulation effect at modeled upstream projects, and modified to a common level of irrigation depletions (2010 level) and reservoir evaporation. As in the AOP18, these flows were further adjusted to include net Grand Coulee pumping updates from the PNCA 1 February 2012 data submittal.

f) Hydro Project Rule Curves

In accordance with the Streamline procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage", and as described in Subsection 2(b) of this document, the AOP19 system regulation studies use the same hydro project rule curves as the AOP18. Please refer to the document, Columbia River Treaty Hydroelectric Operating Plan Assured Operating Plan for Operating Year 2017-18 (AOP18) for notable assumptions affecting hydro project rule curves.

g) Other Hydro Project Operating Procedures, Constraints, and Plant Data

In accordance with the Streamline procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage", and as described in Subsection 2(b) of this document, the AOP19 system regulation studies use the same hydro project operating procedures, constraints and plant data as the AOP18. Please refer to the AOP18 document for notable assumptions affecting operating procedures, constraints, and plant data.

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[1] "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 18-41," dated 22 January 2013.

[2] The conversion factors used are:
(a) million acre-feet (Maf) times 1.2335 equals cubic kilometers (km^3);
(b) thousand second-foot-days (ksfd) times 2.4466 equals cubic hectometers (hm^3);
(c) cubic feet per second (cfs) divided by 35.3147 equals cubic meters per second (m^3/s); and
(d) feet (ft) times 0.3048 equals meters (m).

[3] '2010 Level Modified Streamflow, 1928-2008' (document DOE/BP-4352) published by Bonneville Power Administration (BPA), Portland, Oregon (dated August 2011).

[4] "Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998 Through September 15, 2024" between the Canadian Entity and the United States Entity, dated 29 March 1999.

[5] October 2012 Final Study #S104-WB-20121129-173308 of the "2012 Pacific Northwest Loads & Resources Study, Operating Years 2014 through 2023".

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2018-19 ASSURED OPERATING PLAN

		Target Operation		Target Operation Limits		
Period	End of Previous Period Arrow Storage Content (ksfd)	Period Average Outflow (cfs)	End-of-Period Treaty Storage Content 1/ (ksfd)	Minimum Treaty Storage Content 2/ (ksfd)	Maximum Outflow 1/ (cfs)	Minimum Outflow (cfs)
August 1-15	3,300 - FULL	-	3,494.1	-	34,000	15,000
	2,490 - 3,300	28,000	-	0	-	15,000
	0 - 2,490	32,000	-	0	-	15,000
	0 - 0	32,000	-	0	-	15,000
August 16-31	3,400 - FULL	-	3,529.20	-	34,000	15,000
	2,600 - 3,400	24,000	-	0	-	15,000
	2,000 - 2,600	29,000	-	0	-	15,000
	0 - 2,000	32,000	-	0	-	15,000
September	3,000 - FULL	-	3,529.2	-	34,000	10,000
	1,600 - 3,000	27,000	-	0	-	10,000
	0 - 1,600	32,000	-	0	-	10,000
	0 - 0	32,000	-	0	-	10,000
October	3,000 - FULL	-	3,404.1	-	34,000	10,000
	1,600 - 3,000	23,000	-	0	-	10,000
	1,080 - 1,600	24,000	-	0	-	10,000
	0 - 1,080	32,000	-	0	-	10,000
November	3,100 - FULL	19,000	-	0	-	10,000
	2,770 - 3,100	21,000	-	0	-	10,000
	1,000 - 2,770	26,000	-	0	-	10,000
	0 - 1,000	32,000	-	0	-	10,000
December	2,510 - FULL	23,000	-	204.1	-	10,000
	2,460 - 2,510	28,000	-	204.1	-	10,000
	400 - 2,460	29,000	-	204.1	-	10,000
	0 - 400	32,000	-	204.1	-	10,000
January	2,170 - FULL	24,000	-	204.1	-	12,000
	1,950 - 2,170	21,000	-	204.1	-	12,000
	1,870 - 1,950	27,000	-	204.1	-	12,000
	0 - 1,870	29,000	-	204.1	-	12,000
February	1,350 - FULL	23,000	-	0	-	12,000
	920 - 1,350	25,000	-	0	-	12,000
	350 - 920	27,000	-	0	-	12,000
	0 - 350	29,000	-	0	-	12,000
March	500 - FULL	10,000	-	0	-	12,000
	340 - 500	17,000	-	0	-	12,000
	170 - 340	23,000	-	0	-	12,000
	0 - 170	26,000	-	0	-	12,000
April 1-15	650 - FULL	15,000	-	0	-	12,000
	340 - 650	12,000	-	0	-	12,000
	170 - 340	20,000	-	0	-	12,000
	0 - 170	26,000	-	0	-	12,000
April 16-30	720 - FULL	10,000	-	0	-	10,000
	570 - 720	15,000	-	0	-	10,000
	0 - 570	10,000	-	0	-	10,000
	0 - 0	10,000	-	0	-	10,000
May	580 - FULL	8,000	-	0	-	8,000
	550 - 580	10,000	-	0	-	8,000
	250 - 550	8,000	-	0	-	8,000
	0 - 250	10,000	-	0	-	8,000
June	1,350 - FULL	8,000	-	0	-	8,000
	1,130 - 1,350	10,000	-	0	-	8,000
	0 - 1,130	16,000	-	0	-	8,000
	0 - 0	16,000	-	0	-	8,000
July	2,900 - FULL	-	3,436.20	-	34,000	10,000
	2,300 - 2,900	17,000	-	0	-	10,000
	0 - 2,300	32,000	-	0	-	10,000
	0 - 0	32,000	-	0	-	10,000

Notes:

1/ If the Mica target end-of-period storage content is less than 3,529.2 ksfd, then a maximum outflow of 34,000 cfs w ill apply.

2/ Mica outflow s w ill be reduced to minimum to maintain the reservoir above the minimum Treaty storage content.
This w ill override any flow target.

TABLE 1.1a
(English Units)
ARROW PROJECT OPERATING CRITERIA
DEFINITION
2018-19 ASSURED OPERATING PLAN

Period	Volume Runoff Period	The Dalles Volume Runoff (Maf)	Maximum Storage Limit 1/ 2/ (ksfd)	Maximum Outflow Limit 3/ (cfs)	Minimum Outflow Limit 4/ (cfs)
August 15 - December	-		URC	-	10,000
January	-		URC	70,000	10,000
February	1 Feb - 31 Jul	≤ 70	URC	60,000	20,000
		>70 to <80	URC to 1,500		
		≥ 80	1,500		
March	1 Mar - 31 Jul	≤ 65	URC	-	20,000
		>65 to <75	URC to 900		
		≥ 75	900		
April 15	1 Apr - 31 Jul	≤ 60	URC	-	15,000
		>60 to <65	URC to 900		
		≥ 65	900		
April 30	1 Apr - 31 Jul	≤ 60	URC	-	12,000
		>60 to <65	URC to 800		
		≥ 65	800		
May	1 May - 31 Jul	≤ 65	URC	-	5,000
		>65 to <70	URC to 2,200		
		≥ 70	2,200		
June	1 Jun - 31 Jul	≤ 37	URC	-	5,000
		>37 to <40	URC to 3,300		
		≥ 40	3,300		
July	-		URC	-	10,000

Notes:

1/ If the Maximum Storage Limit is computed to be above the URC, then the URC will apply.

2/ Interpolate when there are two values. For example, if the February-July volume runoff is between 70 Maf and 80 Maf, then the Maximum Storage Limit is interpolated between February's URC and 1,500 ksfd.

3/ The Maximum Average Monthly Outflow Limit takes precedence over the Maximum Storage Limit. However, the Maximum Outflow Limit may be exceeded to avoid storage above the URC.

4/ The Minimum Average Monthly Outflow Limit is an operating limit and may be reduced to as low as 5,000 cfs (Treaty minimum) to avoid drafting Mica+Arrow storage beyond 14.1 Maf.

TABLE 1.1b
(English Units)
ARROW PROJECT OPERATING CRITERIA
30 YEAR OPERATING DATA
FOR 2018-19 ASSURED OPERATING PLAN

	AUG15-DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
Maximum Average Monthly Flow Limits (cfs)									
	-	70,000	60,000	-	-	-	-	-	-
Minimum Average Monthly Flow Limits (cfs)									
	10,000	10,000	20,000	20,000	15,000	12,000	5,000	5,000	10,000
End-of-Period Maximum Storage Limits (ksfd)									
1928-29	-	-	URC	URC	URC	URC	URC	URC	-
1929-30	-	-	URC	URC	URC	URC	URC	URC	-
1930-31	-	-	URC	URC	URC	URC	URC	URC	-
1931-32	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1932-33	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1933-34	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1934-35	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1935-36	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	URC	-
1937-38	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1938-39	-	-	1914.5	1185.2	900.0	800.0	URC	URC	-
1939-40	-	-	2032.0	1584.1	1864.3	1821.2	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1942-43	-	-	1500.0	900.0	900.0	800.0	2200.0	3300.0	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	1792.2	1217.1	900.0	800.0	URC	3507.1	-
1945-46	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1946-47	-	-	1500.0	900.0	900.0	800.0	2200.0	3343.7	-
1947-48	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1948-49	-	-	1500.0	900.0	900.0	800.0	2666.6	URC	-
1949-50	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1950-51	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1951-52	-	-	1500.0	900.0	900.0	800.0	2200.0	3335.8	-
1952-53	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1953-54	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1954-55	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1955-56	-	-	1500.0	900.0	900.0	800.0	2200.0	3300.0	-
1956-57	-	-	1500.0	900.0	900.0	800.0	2200.0	3336.7	-
1957-58	-	-	1500.0	900.0	900.0	800.0	2200.0	3568.7	-

TABLE 1.1c
APOC IMPLEMENTATION
DISTRIBUTION FACTORS FOR THE DALLES
2018-19 ASSURED OPERATING PLAN

Forecast Date	Forecast Period	The Dalles Distribution Factors 1/ Jan-Jul	Feb-Jul	Mar-Jul	Apr-Jul	May-Jul	Jun-Jul
1-Jan	1 Jan - 31 Jul	1.0000	0.9440	0.8860	0.8080	0.6800	0.4270
1-Feb	1 Feb - 31 Jul		1.0000	0.9390	0.8560	0.7200	0.4520
1-Mar	1 Mar - 31 Jul			1.0000	0.9120	0.7670	0.4810
1-Apr	1 Apr - 31 Jul				1.0000	0.8410	0.5280
1-May	1 May - 31 Jul					1.0000	0.6280
1-Jun	1 Jun - 31 Jul						1.0000

Notes:
1/ Unless otherwise agreed, the DOP19 will apply these distribution factors to the monthly volume forecast at The Dalles for computing the Month - July runoff volumes required by the APOC. These distribution factors are calculated from the 2010 Modified Flows mean 80 year Jan - Jul, Feb - Jul, etc., volumes.

For Example, in the month of May:

	From Table 1.1c			**Look up Table 1.1a**			
1 May Forecast Forecast Volume = 64 Maf (May-Jul)	The Dalles Distribution Factor	Month-Jul Volume Runoff (Maf)	(km^3)	The Dalles Volume Runoff (Maf)	(km^3)	Maximum Storage Limit (ksfd)	(hm^3)
May	1.0000	64.0	78.9	≤ 65	≤ 80.2	URC	URC
June	0.6280	40.2	49.6	≥ 40	≥ 49.3	3300	8073.7

TABLE 2
COMPARISON OF 2018-19 ASSURED OPERATING PLAN
STUDY RESULTS (BASED ON THE 2017-18 ASSURED OPERATING PLAN)

Study 19-41 provides Optimum Generation in Canada and in the United States.
Study 19-11 provides Optimum Generation in the United States only.

	Study No. 19-41	Study No. 19-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	11821.4	11821.9	-0.5		
Canada 2/, 3/	3028.6	3010.1	18.6		
Total	14850.0	14832.0	18.0	3	54.0
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	29546.6	29511.3	35.3		
Canada 2/, 5/	6432.9	6395.7	37.2		
Total	35979.5	35907.0	72.5	1	72.5
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3315.0	3292.3	22.7		
Canada 2/, 7/	289.0	313.1	-24.1		
Total	3604.0	3605.4	-1.4	2	-2.8
			Net Change in Value =		123.7

1/ U.S. system firm energy capability was determined over the U.S. system critical period beginning 16 August 1928 and ending 29 February 1932.

2/ Canadian system includes Mica, Arrow, Revelstoke, Kootenay Canal, Corra Linn, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile and Waneta.

3/ Canadian system firm energy capability was determined over the Canadian system critical period beginning 1 October 1940 and ending 30 April 1946.

4/ U.S. system dependable peaking capability was updated to be from January 1932.

5/ Canadian system dependable peaking capability was determined from December 1944.

6/ U.S. system 30-year average secondary energy limited to secondary market.

7/ Canadian system 30-year average generation minus firm energy capability.

TABLE 3
(English Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3529.2	3361.5	3067.0	2614.2	1489.2	958.8	783.8	788.1	775.8	384.1	685.5	2332.8	3429.1
1929-30	3529.2	3520.6	3275.7	2984.9	2358.8	1775.8	607.2	40.8	0.0	0.0	219.4	870.4	2371.2	3324.1
1930-31	3529.2	3529.2	3369.1	3057.5	2496.6	1665.1	770.2	187.1	0.0	0.0	0.0	673.2	2034.2	2553.7
1931-32	2582.1	2536.1	2089.1	1648.9	1121.9	253.7	0.0	0.0						
							ARROW							
1928-29	3579.6	3579.6	3513.0	3571.7	3484.4	3497.7	2190.0	831.7	410.7	315.2	746.8	1824.6	3363.4	3522.7
1929-30	3579.1	3499.9	2950.2	2296.8	1756.8	1283.9	513.5	88.8	0.0	104.9	453.6	1551.2	2653.4	3258.1
1930-31	3378.9	3466.4	3179.6	2686.6	1981.7	1450.4	679.6	114.2	0.0	0.0	0.1	768.8	1837.0	2133.4
1931-32	1821.1	1627.8	1414.4	1114.9	318.4	0.0	0.0	0.0						
							DUNCAN							
1928-29	705.8	705.8	625.0	600.0	550.0	450.0	250.0	93.0	102.0	107.5	118.8	236.3	511.1	698.0
1929-30	700.0	675.0	550.0	500.0	450.0	300.0	100.0	75.0	0.0	13.4	46.5	161.5	381.1	550.0
1930-31	600.0	600.0	525.0	450.0	400.0	200.0	75.0	25.0	0.0	4.8	0.0	157.2	395.1	500.0
1931-32	550.0	550.0	450.0	350.0	150.0	0.0	0.0	0.0						
							COMPOSITE							
1928-29	7814.6	7814.6	7499.5	7238.7	6648.6	5436.9	3398.8	1708.5	1300.8	1198.5	1249.7	2746.4	6207.3	7649.8
1929-30	7808.3	7695.5	6775.9	5781.7	4565.6	3359.7	1220.7	204.6	0.0	118.3	719.5	2583.1	5405.7	7132.2
1930-31	7508.1	7595.6	7073.7	6194.1	4878.3	3315.5	1524.8	326.3	0.0	4.8	0.1	1599.2	4266.3	5187.1
1931-32	4953.2	4713.9	3953.5	3113.8	1590.3	253.7	0.0	0.0						

Note: Individual project rule curves are input to the AOP19 Step 1 study and adjusted to eliminate any Canadian composite crossovers according to Subsection 3(a) of this AOP19 document.

TABLE 4
(English Units)
MICA
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2018 - 19 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	0.0	589.3	767.7	832.7	848.9	843.6	832.0	838.6	863.7	927.0	1500.4	2706.0	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2057.0	1875.8	1818.8	1811.0	1854.8	2366.8	2986.3	3529.2
1929-30							1033.6	812.1	746.6	757.0	917.1	1763.0	2696.2	"
1930-31							1291.8	1079.5	1009.1	997.8	1091.6	1781.9	2772.5	"
1931-32							474.2	268.6	205.4	194.9	316.0	1118.6	2520.1	"
1932-33							380.6	210.5	164.6	152.0	233.5	1017.9	2353.9	"
1933-34							0.0	0.0	0.0	0.0	0.0	764.9	2611.0	"
1934-35							724.1	535.4	501.5	508.9	582.7	1296.7	2459.8	"
1935-36							546.5	358.1	313.1	300.1	399.0	1283.4	2739.4	"
1936-37							2043.8	1841.9	1770.1	1751.4	1843.3	2379.0	3018.6	"
1937-38							753.4	564.9	501.4	495.4	592.0	1341.9	2613.9	"
1938-39							1048.3	904.2	847.9	862.5	977.2	1756.8	2993.0	"
1939-40							829.8	648.8	610.1	618.7	751.9	1554.4	2748.2	"
1940-41							1477.1	1285.6	1234.5	1242.5	1422.8	2158.8	3000.3	"
1941-42							1223.8	1036.2	976.9	961.7	1041.1	1712.0	2795.5	"
1942-43							1391.0	1180.9	1118.4	1103.0	1258.4	1967.1	2857.4	"
1943-44							2149.6	1932.1	1873.8	1864.2	1935.5	2488.2	3161.3	"
1944-45							1992.7	1812.2	1767.8	1768.9	1821.3	2330.7	3049.1	"
1945-46							174.2	0.0	0.0	0.0	0.0	818.0	2515.9	"
1946-47							288.1	122.5	86.6	85.4	206.1	1077.7	2585.6	"
1947-48							236.9	50.7	0.0	0.0	56.6	874.0	2469.8	"
1948-49							1935.2	1725.2	1645.5	1629.6	1709.7	2244.7	3258.6	"
1949-50							592.8	367.4	292.3	269.8	358.3	1094.3	2277.0	"
1950-51							584.1	406.4	363.4	358.6	476.1	1213.0	2646.5	"
1951-52							991.2	771.3	702.4	674.1	759.2	1507.2	2797.1	"
1952-53							1272.7	1071.0	1011.3	995.7	1058.6	1661.8	2763.3	"
1953-54							147.4	0.0	0.0	0.0	1.5	790.5	2248.5	"
1954-55							908.0	734.1	691.2	688.4	778.3	1433.8	2447.2	"
1955-56							455.9	263.9	200.8	180.8	273.4	1111.3	2559.2	"
1956-57							624.7	425.5	376.9	369.1	462.1	1197.1	2897.1	"
1957-58							458.2	271.9	229.9	227.5	336.6	1094.3	2654.3	"
DISTRIBUTION FACTORS							0.9760	0.9790	0.9750	0.9820	0.9650	0.7920	0.5060	N/A
FORECAST ERRORS (KSFD)							727.9	521.8	455.2	420.2	420.2	401.4	397.0	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	9600	20000	30000
VARIABLE REFILL CURVES					80	MAF	3000	3000	3000	3000	3000	3000	20000	27200
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	3000	3000	3000	3000	3000	3000	12000	23000
					110	MAF	3000	3000	3000	3000	3000	3000	12000	23000
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					110	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (KSFD)							421.6	22.5	0.0	0.0				

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2018 - 19 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	0.0	0.0	0.0	0.0	0.0	514.0	661.8	743.3	824.0	992.8	2267.6	3507.2	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							2683.4	2461.2	2346.6	2276.2	2406.9	3197.5	3570.7	3579.6
1929-30							999.9	826.2	868.8	873.7	1145.6	2586.4	3368.3	"
1930-31							1504.2	1281.7	1188.2	1151.8	1369.6	2441.5	3379.0	"
1931-32							0.0	0.0	0.0	0.0	227.2	1660.1	3065.5	"
1932-33							375.4	326.5	338.6	335.0	551.4	1804.4	3000.0	"
1933-34							0.0	0.0	0.0	0.0	158.0	2270.7	3494.5	"
1934-35							637.6	577.6	686.1	710.2	898.5	2019.1	3113.4	"
1935-36							697.0	540.5	493.6	461.5	633.5	2007.9	3412.6	"
1936-37							2992.4	2725.7	2600.5	2501.4	2653.4	3371.6	3579.6	"
1937-38							988.8	897.3	913.6	946.0	1173.8	2304.5	3311.0	"
1938-39							1230.9	1058.0	975.8	940.6	1235.0	2531.2	3579.6	"
1939-40							882.0	786.4	834.4	921.9	1202.4	2310.5	3448.8	"
1940-41							2139.1	1965.9	1909.8	1995.1	2436.1	3482.1	3579.6	"
1941-42							2110.4	1941.9	1879.1	1810.0	2016.4	2984.6	"	"
1942-43							2570.9	2333.9	2245.3	2160.9	2460.0	3479.7	"	"
1943-44							3504.1	3291.3	3189.3	3093.1	3264.1	3579.6	"	"
1944-45							2862.1	2694.6	2617.9	2575.7	2701.7	3389.2	"	"
1945-46							99.2	153.9	117.5	96.6	431.7	1784.6	3203.5	"
1946-47							720.4	679.7	682.8	705.2	960.4	2204.4	3302.6	"
1947-48							500.3	551.7	547.5	487.1	688.5	1899.2	3230.8	"
1948-49							2245.8	2041.5	1974.9	1916.6	2153.0	3214.3	3579.6	"
1949-50							573.6	457.6	473.4	474.0	678.5	1820.6	2876.1	"
1950-51							877.0	794.4	835.4	800.5	1048.1	2173.6	3373.5	"
1951-52							942.4	786.9	806.2	779.4	968.1	2226.6	3433.7	"
1952-53							1602.1	1409.8	1356.2	1298.6	1452.0	2490.6	3380.7	"
1953-54							0.0	0.0	5.1	10.6	302.9	1526.9	2885.2	"
1954-55							652.3	591.8	630.6	606.0	821.9	1894.3	2855.5	"
1955-56							355.9	253.0	271.4	266.3	502.6	1894.2	3233.3	"
1956-57							424.6	302.9	313.3	296.7	526.0	1751.1	3552.3	"
1957-58							223.5	116.5	172.7	239.8	535.7	1780.7	3269.7	"
DISTRIBUTION FACTORS							0.9730	0.9760	0.9700	0.9740	0.9510	0.7420	0.4670	N/A
FORECAST ERRORS (KSFD)							1485.1	1095.3	954.2	809.7	809.7	723.2	679.4	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	9500	33000	60000
VARIABLE REFILL CURVES					80	MAF	5000	5000	5000	5000	5000	5000	31000	50000
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	5000	5000	5000	5000	5000	5000	31000	50000
					110	MAF	5000	5000	5000	5000	5000	5000	31000	50000
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					110	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (KSFD)							411.3	37.5	0.0	0.0				

TABLE 6
(English Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2018 - 19 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	0.0	1.3	32.0	49.5	60.7	70.9	80.1	94.2	105.0	120.6	277.8	503.7	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							349.0	332.0	340.3	338.2	354.8	460.7	595.8	705.8
1929-30							347.4	330.0	338.1	335.6	359.8	480.9	607.6	"
1930-31							291.8	275.7	287.4	290.0	312.7	430.9	595.8	"
1931-32							16.8	2.3	21.1	29.2	64.5	249.0	505.6	"
1932-33							0.0	0.0	0.0	0.0	0.0	75.0	367.5	"
1933-34							33.4	36.2	60.2	74.4	120.7	328.3	578.1	"
1934-35							82.2	72.9	95.8	97.6	121.8	286.5	500.7	"
1935-36							58.5	43.4	55.0	55.5	83.0	283.2	557.3	"
1936-37							284.7	266.8	277.1	275.0	296.0	416.0	577.1	"
1937-38							76.9	68.7	84.8	93.3	123.5	297.9	534.3	"
1938-39							129.4	118.9	131.7	135.2	166.9	338.1	581.0	"
1939-40							116.3	110.7	131.2	144.2	178.6	341.0	567.1	"
1940-41							200.5	192.1	208.5	223.2	268.7	420.3	590.3	"
1941-42							194.6	188.6	204.8	208.4	237.7	383.8	570.9	"
1942-43							206.8	193.5	208.4	210.4	249.2	405.5	563.5	"
1943-44							355.1	342.7	355.7	355.5	379.1	487.6	626.9	"
1944-45							277.7	265.6	279.7	280.1	298.3	416.7	585.2	"
1945-46							0.0	0.0	0.0	0.0	0.0	190.6	503.3	"
1946-47							"	"	"	"	30.6	234.6	513.0	"
1947-48							39.8	28.6	46.4	47.0	71.9	251.9	527.9	"
1948-49							266.1	249.8	261.4	260.2	285.5	422.6	630.1	"
1949-50							66.2	50.4	64.6	64.0	90.5	255.7	463.2	"
1950-51							0.0	0.0	0.0	0.0	31.9	220.3	495.4	"
1951-52							97.0	83.3	100.8	101.2	127.1	312.8	546.3	"
1952-53							94.2	83.2	98.7	100.6	123.6	287.4	508.7	"
1953-54							0.0	0.0	0.0	0.0	0.0	150.2	438.2	"
1954-55							30.1	18.6	34.1	37.0	65.1	232.4	438.0	"
1955-56							0.0	0.0	0.0	0.0	0.0	200.9	496.2	"
1956-57							50.0	32.3	45.9	48.2	77.4	250.5	564.6	"
1957-58							0.0	0.0	0.0	0.0	2.6	190.5	516.4	"
DISTRIBUTION FACTORS							0.9740	0.9800	0.9760	0.9790	0.9570	0.7510	0.4810	N/A
FORECAST ERRORS (KSFD)							127.6	104.3	105.0	93.8	93.8	86.9	78.0	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	100	100	100	100	100	100	100	100	100	100	100	100	500	800
VARIABLE REFILL CURVES					80	MAF	100	100	100	100	100	100	1800	2500
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	100	100	100	100	100	100	1800	2500
					110	MAF	100	100	100	100	100	100	1800	2500
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					110	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (KSFD)							11.8	6.3	0.0	0.0				

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3529.2	3529.2	3529.2	3428.4	3428.4	3331.6	3207.0	3094.5	2969.9	2969.9	2969.9	3311.0	3529.2	3529.2
1929-30	"	"	"	"	"	"	3155.2	2996.1	2819.7	2819.7	2819.7	2903.4	3283.0	"
1930-31	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3331.6	3529.2	"
1931-32	"	"	"	"	"	"	2698.3	2105.4	1472.2	1472.2	1472.2	2313.5	3451.1	"
1932-33	"	"	"	"	"	"	2691.3	2112.5	"	"	"	1661.5	3282.4	"
1933-34	"	"	"	"	"	"	"	"	"	1519.5	1984.4	3370.8	3529.2	"
1934-35	"	"	"	"	"	"	"	"	"	1472.2	1472.2	1918.6	3333.8	"
1935-36	"	"	"	"	"	"	2698.3	2105.4	"	"	1665.5	2827.7	3529.2	"
1936-37	"	"	"	"	"	"	3141.9	2970.8	2781.2	2781.2	2781.2	3001.8	"	"
1937-38	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	1984.4	"	"
1938-39	"	"	"	"	"	"	2854.7	2423.4	1946.5	1946.5	2014.6	3214.2	3420.0	"
1939-40	"	"	"	"	"	"	3013.4	2715.7	2397.6	2397.6	2397.6	3306.3	3429.6	"
1940-41	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3516.5	3529.2	"
1941-42	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	1955.6	3280.3	"
1942-43	"	"	"	"	"	"	"	"	"	1505.1	1712.9	2206.6	3284.4	"
1943-44	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3521.5	3529.2	"
1944-45	"	"	"	"	"	"	2839.7	2395.0	1903.2	1903.2	1903.2	2217.0	"	"
1945-46	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2712.5	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	1503.0	2578.8	"	"
1947-48	"	"	"	"	"	"	2698.3	2105.4	"	"	1472.2	2327.9	"	"
1948-49	"	"	"	"	"	"	2691.3	2112.5	"	"	1498.9	2430.8	3527.1	"
1949-50	"	"	"	"	"	"	"	"	"	"	1472.2	1546.2	3126.0	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2457.5	3529.2	"
1951-52	"	"	"	"	"	"	2698.3	2105.4	"	"	1577.1	2531.5	"	"
1952-53	"	"	"	"	"	"	2691.3	2112.5	"	"	1472.2	1932.9	3391.4	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	2144.8	2772.2	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1472.2	3052.0	"
1955-56	"	"	"	"	"	"	2698.3	2105.4	"	"	"	2284.7	3529.2	"
1956-57	"	"	"	"	"	"	2691.3	2112.5	"	"	"	2984.1	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2613.8	"	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3579.6	3579.6	3579.6	3453.6	3453.6	3223.7	3191.1	3161.6	3129.1	3129.1	3129.1	3208.8	3579.6	3579.6
1929-30	"	"	"	"	"	"	3143.1	3070.3	2989.7	2989.7	2989.7	2990.3	"	"
1930-31	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3579.6	"	"
1931-32	"	"	"	"	"	"	2726.5	2261.7	1764.6	1764.6	1764.6	2042.3	"	"
1932-33	"	"	"	"	"	"	2721.0	2267.2	"	"	"	1764.6	3211.2	"
1933-34	"	"	"	"	"	"	"	"	"	1779.1	2271.0	2436.1	3579.6	"
1934-35	"	"	"	"	"	"	"	"	"	1764.6	1764.6	2053.2	"	"
1935-36	"	"	"	"	"	"	2726.5	2261.7	"	"	1878.9	3113.1	"	"
1936-37	"	"	"	"	"	"	3130.6	3046.7	2953.7	2953.7	2953.7	2953.7	"	"
1937-38	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	1986.0	"	"
1938-39	"	"	"	"	"	"	2862.2	2535.6	2174.1	2174.1	2185.4	2396.2	"	"
1939-40	"	"	"	"	"	"	3009.3	2809.1	2594.8	2594.8	2594.8	3140.4	"	"
1940-41	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3416.6	"	"
1941-42	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	1969.7	2918.9	"
1942-43	"	"	"	"	"	"	"	"	"	"	2033.2	2494.2	3579.6	"
1943-44	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3223.7	"	"
1944-45	"	"	"	"	"	"	2849.3	2511.1	2136.7	2136.7	2136.7	2169.9	"	"
1945-46	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	1878.9	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	2211.1	"	"
1947-48	"	"	"	"	"	"	2726.5	2261.7	"	"	"	1880.7	"	"
1948-49	"	"	"	"	"	"	2721.0	2267.2	"	"	1771.8	2915.3	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	1764.6	1764.6	2997.0	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2138.5	3579.6	"
1951-52	"	"	"	"	"	"	2726.5	2261.7	"	"	1866.2	2830.0	"	"
1952-53	"	"	"	"	"	"	2721.0	2267.2	"	"	1764.6	2007.8	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	2111.3	2900.8	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1764.6	3314.6	"
1955-56	"	"	"	"	"	"	2726.5	2261.7	"	"	"	2383.5	3579.6	"
1956-57	"	"	"	"	"	"	2721.0	2267.2	"	"	"	2646.7	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2652.1	"	"

TABLE 9
(English Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	705.8	705.8	705.8	705.8	705.8	504.1	418.0	340.3	340.3	340.3	340.3	429.1	704.3	705.8
1929-30	"	"	"	"	"	"	408.7	322.6	322.6	322.6	322.6	357.1	577.0	"
1930-31	"	"	"	"	"	"	390.7	288.3	288.3	288.3	288.3	426.5	664.5	"
1931-32	"	"	"	"	"	"	277.3	93.2	65.7	65.7	66.9	277.0	626.8	"
1932-33	"	"	"	"	"	"	273.7	"	"	"	65.7	130.6	558.8	"
1933-34	"	"	"	"	"	"	"	"	"	90.2	168.0	422.2	657.4	"
1934-35	"	"	"	"	"	"	"	"	"	65.7	65.7	180.2	504.9	"
1935-36	"	"	"	"	"	"	277.3	"	"	69.3	127.5	390.9	697.8	"
1936-37	"	"	"	"	"	"	374.8	258.1	258.1	258.1	258.1	334.6	583.1	"
1937-38	"	"	"	"	"	"	290.1	115.9	97.0	97.0	97.0	250.4	584.8	"
1938-39	"	"	"	"	"	"	285.1	109.0	87.5	87.5	119.7	368.0	576.9	"
1939-40	"	"	"	"	"	"	301.1	126.5	111.4	111.4	111.4	321.7	596.3	"
1940-41	"	"	"	"	"	"	344.4	200.1	200.1	200.1	200.1	327.1	579.4	"
1941-42	"	"	"	"	"	"	326.1	165.6	165.1	165.1	165.1	278.5	501.6	"
1942-43	"	"	"	"	"	"	329.3	171.4	171.4	190.1	239.8	361.7	564.7	"
1943-44	"	"	"	"	"	"	412.5	327.2	327.2	327.2	327.2	386.6	617.6	"
1944-45	"	"	"	"	"	"	381.5	270.7	270.7	270.7	270.7	364.2	622.7	"
1945-46	"	"	"	"	"	"	273.7	93.2	65.7	65.7	79.2	360.9	698.4	"
1946-47	"	"	"	"	"	"	"	"	"	"	90.8	335.2	654.3	"
1947-48	"	"	"	"	"	"	277.3	"	"	"	65.7	281.3	673.3	"
1948-49	"	"	"	"	"	"	368.0	245.0	245.0	245.0	266.2	503.0	705.8	"
1949-50	"	"	"	"	"	"	273.7	93.2	65.7	65.7	65.7	105.5	476.7	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	291.7	560.6	"
1951-52	"	"	"	"	"	"	277.3	"	"	"	114.1	323.5	623.7	"
1952-53	"	"	"	"	"	"	273.7	"	"	"	65.7	188.8	493.2	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	252.5	539.2	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	65.5	462.6	"
1955-56	"	"	"	"	"	"	277.3	"	"	"	"	295.4	659.3	"
1956-57	"	"	"	"	"	"	273.7	"	"	"	71.2	399.5	705.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	66.3	371.9	"	"

TABLE 10
(English Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3398.8	1756.7	1683.9	1795.2	2040.4	4045.8	6724.3	7814.6
1929-30	"	"	"	"	"	"	2208.7	1731.3	1591.9	1688.5	2030.5	"	6575.6	"
1930-31	"	"	"	"	"	"	2713.0	1756.7	1683.9	1795.2	2040.4	"	6596.1	"
1931-32	"	"	"	"	"	"	902.3	312.4	226.5	224.1	607.7	3027.7	6091.2	"
1932-33	"	"	"	"	"	"	844.7	543.3	503.2	487.0	784.9	2857.5	5721.4	"
1933-34	"	"	"	"	"	"	866.3	96.2	60.2	74.4	278.6	3310.3	6616.6	"
1934-35	"	"	"	"	"	"	1443.9	1185.9	1253.3	1284.8	1546.9	3496.0	6073.9	"
1935-36	"	"	"	"	"	"	1302.0	942.0	861.7	817.1	1115.5	3569.1	6629.7	"
1936-37	"	"	"	"	"	"	3398.8	1756.7	1683.9	1795.2	2040.4	4045.8	6724.3	"
1937-38	"	"	"	"	"	"	1819.1	1465.3	1329.5	1412.7	1681.8	3578.3	6436.0	"
1938-39	"	"	"	"	"	"	2319.1	1756.7	1669.4	1774.0	2039.5	4045.8	6724.3	"
1939-40	"	"	"	"	"	"	1828.1	1528.2	1455.4	1550.2	1856.1	"	6665.9	"
1940-41	"	"	"	"	"	"	3298.4	1756.7	1683.9	1795.2	2040.4	"	6724.3	"
1941-42	"	"	"	"	"	"	3263.8	"	"	"	"	3747.9	6126.5	"
1942-43	"	"	"	"	"	"	3355.6	"	"	"	"	4045.8	6724.3	"
1943-44	"	"	"	"	"	"	3398.8	"	"	"	"	"	"	"
1944-45	"	"	"	"	"	"	"	"	"	"	"	3948.1	"	"
1945-46	"	"	"	"	"	"	844.7	182.7	117.5	96.6	431.7	2793.2	6222.7	"
1946-47	"	"	"	"	"	"	1153.8	808.5	769.4	790.6	1197.1	3516.7	6399.3	"
1947-48	"	"	"	"	"	"	961.7	631.0	593.9	534.1	810.8	3006.6	6211.7	"
1948-49	"	"	"	"	"	"	3398.8	1756.7	1683.9	1795.2	2040.4	4045.8	6724.3	"
1949-50	"	"	"	"	"	"	1232.6	875.4	830.3	807.8	1102.5	2964.4	5616.3	"
1950-51	"	"	"	"	"	"	1472.9	1207.1	1106.7	1159.1	1500.8	3571.8	6515.4	"
1951-52	"	"	"	"	"	"	1998.2	1641.5	1511.4	1519.2	1841.4	4004.8	6650.8	"
1952-53	"	"	"	"	"	"	2655.1	1746.9	1647.6	1753.4	1985.5	3697.0	6579.9	"
1953-54	"	"	"	"	"	"	844.7	66.3	5.1	10.6	304.4	2467.6	5571.9	"
1954-55	"	"	"	"	"	"	1590.4	1344.5	1355.9	1331.4	1665.3	3263.9	5740.7	"
1955-56	"	"	"	"	"	"	879.0	523.2	472.2	447.1	776.0	3206.4	6288.7	"
1956-57	"	"	"	"	"	"	1099.3	760.7	736.1	714.0	1059.3	3198.7	6724.3	"
1957-58	"	"	"	"	"	"	881.3	394.7	402.6	467.3	874.9	3065.5	6435.1	"

TABLE 11
(English Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7499.5	7238.7	6648.7	5436.9	3398.8	1708.5	1300.9	1198.4	1249.7	2746.4	6207.3	7649.8
1929-30	7808.3	7695.5	6726.0	5781.7	4565.6	3359.7	1220.7	204.6	0.0	118.3	719.5	2583.1	5405.7	7132.2
1930-31	7508.1	7595.6	7048.7	6194.1	4878.3	3315.4	1524.8	326.3	0.0	4.8	0.1	1599.2	4266.3	5187.1
1931-32	4953.2	4713.9	3953.5	3113.8	1590.3	253.7	0.0	0.0	1.7	121.6	460.8	2385.4	5823.9	7614.8
1932-33	7746.4	7814.6	6937.1	6351.7	6374.5	5162.9	3053.5	1405.5	503.2	438.5	646.2	2396.1	5721.4	7721.6
1933-34	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3129.7	1546.7	769.8	606.1	1227.7	3310.3	6211.6	7615.2
1934-35	7772.5	7691.8	6775.9	6146.8	6501.5	5162.9	3063.5	1563.3	1226.9	1104.1	1244.8	3095.1	6073.9	7814.6
1935-36	7814.6	7793.4	7398.0	6657.0	5661.7	4163.5	1981.7	900.2	505.5	417.2	874.4	3569.1	6629.7	7721.6
1936-37	7795.2	7690.4	6775.9	5899.7	4678.3	3252.3	1194.8	185.2	0.0	8.7	52.7	1545.4	4547.7	5979.7
1937-38	5972.0	5836.0	5133.1	4501.8	3885.5	3073.1	1819.1	1448.7	780.8	679.9	587.9	2582.3	5756.2	7696.2
1938-39	7673.3	7640.6	7053.2	6609.9	5699.6	4675.0	2525.5	1731.2	1349.8	1382.0	1415.8	4045.8	6034.1	7721.6
1939-40	7808.6	7704.0	6834.1	6331.8	5784.8	5162.9	3038.8	1528.2	1273.0	1361.9	1676.2	4045.8	6052.9	7236.0
1940-41	7325.3	7246.9	6775.9	6702.5	5709.7	4460.2	2853.4	1546.4	1302.4	1519.2	1940.4	3064.3	4799.5	5714.6
1941-42	5559.1	5422.2	5075.4	5540.0	5102.0	5162.9	3283.4	1756.7	1091.6	976.8	879.5	2783.7	5144.0	7589.6
1942-43	7779.5	7771.0	7090.2	6420.0	6177.7	5162.9	3363.0	1756.7	1335.1	1406.8	1444.1	2807.0	5210.1	7721.6
1943-44	7814.6	7814.6	7431.8	7120.6	6503.2	5162.2	3382.6	1720.1	1208.1	1155.3	1174.2	2408.6	4571.9	5340.5
1944-45	5189.6	4985.9	4258.6	3657.8	2363.6	1010.7	204.1	0.0	0.0	0.8	0.0	1829.4	4796.5	6425.4
1945-46	6254.1	6066.9	5331.2	4656.0	3833.2	2974.5	844.7	182.7	0.0	0.0	283.0	2729.8	6200.2	7721.6
1946-47	7814.6	7799.3	7499.5	7120.6	6617.8	5162.9	2970.8	1325.3	769.4	790.6	1197.1	3516.7	6399.3	7814.6
1947-48	7814.6	7791.6	7499.5	7120.6	6617.8	5162.9	2997.3	1262.8	593.9	487.9	689.9	3006.6	6211.7	7814.6
1948-49	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3398.8	1756.7	1363.1	1362.8	1505.7	4045.8	6373.8	7413.0
1949-50	7715.9	7674.4	6836.4	6325.3	6399.5	5162.9	2969.1	1306.7	827.6	766.4	835.7	2252.0	5616.3	7814.6
1950-51	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3051.2	1440.1	997.4	1020.2	1157.8	3570.1	6194.3	7753.3
1951-52	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	2970.2	1641.5	1204.3	1138.4	1458.8	3830.8	6543.2	7721.6
1952-53	7814.6	7779.9	7208.8	6530.9	5541.6	4263.2	2720.2	1746.9	1330.0	1171.0	995.6	2872.8	5824.8	7721.6
1953-54	7805.1	7814.6	7499.5	7120.6	6617.8	5162.9	3029.5	1439.4	554.0	215.2	247.7	2467.6	5571.9	7814.6
1954-55	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3077.4	1464.9	1068.4	1035.0	913.6	2071.9	5740.7	7721.6
1955-56	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3023.0	1298.3	472.2	439.2	776.0	3206.4	6288.7	7721.6
1956-57	7779.5	7814.6	7499.5	7120.6	6617.8	5162.9	2990.4	1338.9	736.1	703.9	889.0	3198.7	6712.0	7721.6
1957-58	7769.6	7685.9	6924.2	6612.8	6063.6	5162.9	3019.8	1420.2	492.9	467.3	656.7	3065.5	6435.1	7721.6
Max	7814.6	7814.6	7499.5	7238.7	6648.7	5436.9	3398.8	1756.7	1363.1	1519.2	1940.4	4045.8	6712.0	7814.6
Median	7800.2	7775.5	7071.7	6611.4	6276.1	5162.9	2993.9	1439.8	775.3	735.2	884.3	2839.9	5929.5	7721.6
Average	7399.7	7351.5	6802.1	6320.0	5671.4	4439.0	2536.7	1231.8	768.6	736.6	906.7	2887.7	5778.8	7345.3
Min	4953.2	4713.9	3953.5	3113.8	1590.3	253.7	0.0	0.0	0.0	0.0	0.0	1545.4	4266.3	5187.1

TABLE 12
(English Units)
COMPARISON OF RECENT ASSURED OPERATING PLAN STUDIES

	2010-11	2011-12 through 2013-14 1/	2014-15	2015-16 through 2016-17 3/	2017-18 through 2018-19 4/
MICA TARGET OPERATION (ksfd or cfs)					
AUG 15	3439.2	3364.2	3379.2	3379.2	3494.1
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	3428.4	3428.4	3428.4	3404.1	3404.1
NOV	21000	21000	22000	21000	19000
DEC	25000	25000	22000	17000	23000
JAN	27000	24000	24000	24000	24000
FEB	21000	21000	21000	26000	23000
MAR	21000	17000	25000	25000	10000
APR 15	22000	20000	17000	21000	15000
APR 30	10000	10000	10000	10000	10000
MAY	8000	8000	8000	8000	8000
JUN	8000	8000	10000	8000	8000
JUL	3467.2	3467.2	3467.2	3436.2	3436.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7794.1	7814.4	7814.6	7814.6	7814.6
1928 DEC	5086	5204	5282.1	5092.5	5436.9
1929 APR15	1048.2	1084.4	1078.2	1024.5	1198.4
1929 JUL	7233.2	7329.8	7500.9	7585.9	7649.8
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd) 2/					
AUG 31	7438.0	7362.8	7406.8	7415.3	7385.9
DEC	4612.9	4630.0	4644.6	4490.1	4524.4
APR15	842.6	908.6	889.3	716.3	811.0
JUL	7268.9	7147.1	7279.9	7303.8	7388.7
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.3	0.1	0.0	0.0	-0.5
U.S. Dependable Peaking Capacity 5/	-19.1	-22.9	-3.9	-2.1	6.9 / 35.3
U.S. Average Annual Usable Secondary Energy	16.0	21.6	21.3	17.6	22.7
BCH Firm Energy	34.4	43.6	44.0	24.0	18.6
BCH Dependable Peaking Capacity	43.8	41.7	47.8	28.2	37.2
BCH Average Annual Usable Secondary Energy	-20.8	-13.9	-33.4	-16.2	-24.1
COORDINATED HYDRO LOAD (MW)					
AUG 15	11138	10969	11187	11367	12028
AUG 31	11167	11104	10971	10944	11399
SEP	11025	11081	9756	9822	10207
OCT	9958	9920	9758	10051	9233
NOV	11333	11458	11821	12152	11434
DEC	13369	13316	13836	13744	13523
JAN	13076	12878	13323	13933	13862
FEB	11902	11721	13179	12876	13006
MAR	10967	10501	12022	11269	11264
APR 15	10241	9786	10476	10894	9583
APR 30	12475	11502	11012	11600	10684
MAY	13493	13287	12198	12166	12344
JUN	14080	13867	12208	11291	11314
JUL	12725	12531	11954	11812	12256
ANNUAL AVERAGE	12039	11856	11819	11794	11689

1/ The AOP 2013-14 and 2012-13 utilize the same system regulation study as the 2011-12.

2/ Prior to AOP15, average content based on 60 years of modified flows. AOP15 through AOP17 averages based on 70 years of modified flows. AOP18 and AOP19 averages based on 80 years of modified flows.

3/ The AOP 2016-17 utilizes the same Step 1 system regulation studies as used in the AOP 2015-16, so these coordinated hydro loads will be used for the DOP17 TSR unless otherwise agreed.

4/ The AOP 2018-19 utilizes the same Step 1 system regulation studies as used in the AOP 2017-18, so these coordinated hydro loads will be used for the DOP19 TSR unless otherwise agreed.

5/ Due to changes between the AOP 2017-18 and the AOP 2018-19 peak load shape, the period in which the U.S. system dependable peaking capability was determined changed from 15 August 1931 to January 1932.

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2018-19 ASSURED OPERATING PLAN

		Target Operation		Target Operation Limits		
Period	End of Previous Period Arrow Storage Content (hm^3)	Period Average Outflow (m^3/s)	End-of-Period Treaty Storage Content 1/ (hm^3)	Minimum Treaty Storage Content 2/ (hm^3)	Maximum Outflow 1/ (m^3/s)	Minimum Outflow (m^3/s)
August 1-15	8,073.8 - FULL	-	8,548.7	-	962.77	424.75
	6,092.0 - 8,073.8	792.87	-	0.0	-	424.75
	0.0 - 6,092.0	906.14	-	0.0	-	424.75
August 16-31	8,318.4 - FULL	-	8,634.5	-	962.77	424.75
	6,361.2 - 8,318.4	679.60	-	0.0	-	424.75
	4,893.2 - 6,361.2	821.19	-	0.0	-	424.75
	0.0 - 4,893.2	906.14	-	0.0	-	424.75
September	7,339.8 - FULL	-	8,634.5	-	962.77	283.17
	3,914.6 - 7,339.8	764.55	-	0.0	-	283.17
	0.0 - 3,914.6	906.14	-	0.0	-	283.17
October	7,339.8 - FULL	-	8,328.5	-	962.77	283.17
	3,914.6 - 7,339.8	651.29	-	0.0	-	283.17
	2,642.3 - 3,914.6	679.60	-	0.0	-	283.17
	0.0 - 2,642.3	906.14	-	0.0	-	283.17
November	7,584.5 - FULL	538.02	-	0.0	-	283.17
	6,777.1 - 7,584.5	594.65	-	0.0	-	283.17
	2,446.6 - 6,777.1	736.24	-	0.0	-	283.17
	0.0 - 2,446.6	906.14	-	0.0	-	283.17
December	6,141.0 - FULL	651.29	-	499.4	-	283.17
	6,018.6 - 6,141.0	792.87	-	499.4	-	283.17
	978.6 - 6,018.6	821.19	-	499.4	-	283.17
	0.0 - 978.6	906.14	-	499.4	-	283.17
January	5,309.1 - FULL	679.60	-	499.4	-	339.80
	4,770.9 - 5,309.1	594.65	-	499.4	-	339.80
	4,575.1 - 4,770.9	764.55	-	499.4	-	339.80
	0.0 - 4,575.1	821.19	-	499.4	-	339.80
February	3,302.9 - FULL	651.29	-	0.0	-	339.80
	2,250.9 - 3,302.9	707.92	-	0.0	-	339.80
	856.3 - 2,250.9	764.55	-	0.0	-	339.80
	0.0 - 856.3	821.19	-	0.0	-	339.80
March	1,223.3 - FULL	283.17	-	0.0	-	339.80
	831.8 - 1,223.3	481.39	-	0.0	-	339.80
	415.9 - 831.8	651.29	-	0.0	-	339.80
	0.0 - 415.9	736.24	-	0.0	-	339.80
April 1-15	1,590.3 - FULL	424.75	-	0.0	-	339.80
	831.8 - 1,590.3	339.80	-	0.0	-	339.80
	415.9 - 831.8	566.34	-	0.0	-	339.80
	0.0 - 415.9	736.24	-	0.0	-	339.80
April 16-30	1,761.6 - FULL	283.17	-	0.0	-	283.17
	1,394.6 - 1,761.6	424.75	-	0.0	-	283.17
	0.0 - 1,394.6	283.17	-	0.0	-	283.17
May	1,419.0 - FULL	226.53	-	0.0	-	226.53
	1,345.6 - 1,419.0	283.17	-	0.0	-	226.53
	611.7 - 1,345.6	226.53	-	0.0	-	226.53
	0.0 - 611.7	283.17	-	0.0	-	226.53
June	3,302.9 - FULL	226.53	-	0.0	-	226.53
	2,764.7 - 3,302.9	283.17	-	0.0	-	226.53
	0.0 - 2,764.7	453.07	-	0.0	-	226.53
July	7,095.1 - FULL	-	8,407.0	-	962.77	283.17
	5,627.2 - 7,095.1	481.39	-	0.0	-	283.17
	0.0 - 5,627.2	906.14	-	0.0	-	283.17

Notes:

1/ If the Mica target end-of-period storage content is less than 8,634.5 hm^3, then a maximum outflow of 962.77 m^3/s will apply.

2/ Mica outflows will be reduced to minimum to maintain the reservoir above the minimum Treaty storage content. This will override any flow target.

TABLE 1.1aM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
DEFINITION
2018-19 ASSURED OPERATING PLAN

Period	Volume Runoff Period	The Dalles Volume Runoff (km^3)	Maximum Storage Limit 1/ 2/ (hm^3)	Maximum Outflow Limit 3/ (m^3/s)	Minimum Outflow Limit 4/ (m^3/s)
August 15 - December	-		URC	-	283.2
January	-		URC	1,982	283.2
February	1 Feb - 31 Jul	≤ 86	URC	1,699	566.3
		>86 to <99	URC to 3,670		
		≥ 99	3,670		
March	1 Mar - 31 Jul	≤ 80	URC	-	566.3
		>80 to <93	URC to 2,202		
		≥ 93	2,202		
April 15	1 Apr - 31 Jul	≤ 74	URC	-	424.8
		>74 to <80	URC to 2,202		
		≥ 80	2,202		
April 30	1 Apr - 31 Jul	≤ 74	URC	-	339.8
		>74 to <80	URC to 1,957		
		≥ 80	1,957		
May	1 May - 31 Jul	≤ 80	URC	-	141.6
		>80 to <86	URC to 5,382		
		≥ 86	5,382		
June	1 Jun - 31 Jul	≤ 46	URC	-	141.6
		>46 to <49	URC to 8,074		
		≥ 49	8,074		
July	-		URC	-	283.2

Notes:

1/ If the Maximum Storage Limit is computed to be above the URC, then the URC will apply.

2/ Interpolate when there are two values. For example, if the February-July volume runoff is between 86 km^3 and 99 km^3, then the Maximum Storage Limit is interpolated between February's URC and 3,670 hm^3.

3/ The Maximum Average Monthly Outflow Limit takes precedence over the Maximum Storage Limit. However, the Maximum Outflow Limit may be exceeded to avoid storage above the URC.

4/ The Minimum Average Monthly Outflow Limit is an operating limit and may be reduced to as low as 141.6 m^3/s (Treaty minimum) to avoid drafting Mica+Arrow storage beyond 17.0 km^3.

TABLE 1.1bM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
30 YEAR OPERATING DATA
FOR 2018-19 ASSURED OPERATING PLAN

	AUG15-DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
Maximum Average Monthly Flow Limits (m^3/s)									
	-	1,982	1,699	-	-	-	-	-	-
Minimum Average Monthly Flow Limits (m^3/s)									
	283.2	283.2	566.3	566.3	424.8	339.8	141.6	141.6	283.2
End-of-Period Maximum Storage Limits (hm^3)									
1928-29	-	-	URC	URC	URC	URC	URC	URC	-
1929-30	-	-	URC	URC	URC	URC	URC	URC	-
1930-31	-	-	URC	URC	URC	URC	URC	URC	-
1931-32	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1932-33	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1933-34	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1934-35	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1935-36	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	URC	-
1937-38	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1938-39	-	-	4684.0	2899.7	2201.9	1957.3	URC	URC	-
1939-40	-	-	4971.4	3875.6	4561.2	4455.7	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1942-43	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8073.7	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	4384.8	2977.7	2201.9	1957.3	URC	8580.4	-
1945-46	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1946-47	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8180.6	-
1947-48	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1948-49	-	-	3669.9	2201.9	2201.9	1957.3	6524.0	URC	-
1949-50	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1950-51	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1951-52	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8161.3	-
1952-53	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1953-54	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1954-55	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1955-56	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8073.7	-
1956-57	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8163.5	-
1957-58	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8731.1	-

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8634.5	8224.2	7503.7	6395.9	3643.5	2345.8	1917.6	1928.2	1898.1	939.7	1677.1	5707.4	8389.6
1929-30	8634.5	8613.5	8014.3	7302.9	5771.0	4344.7	1485.6	99.8	0.0	0.0	536.8	2129.5	5801.4	8132.7
1930-31	8634.5	8634.5	8242.8	7480.5	6108.2	4073.8	1884.4	457.8	0.0	0.0	0.0	1647.1	4976.9	6247.9
1931-32	6317.4	6204.8	5111.2	4034.2	2744.8	620.7	0.0	0.0						
							ARROW							
1928-29	8757.8	8757.8	8594.9	8738.5	8524.9	8557.5	5358.1	2034.8	1004.8	771.2	1827.1	4464.1	8228.9	8618.6
1929-30	8756.6	8562.9	7218.0	5619.4	4298.2	3141.2	1256.3	217.3	0.0	256.6	1109.8	3795.2	6491.8	7971.3
1930-31	8266.8	8480.9	7779.2	6573.0	4848.4	3548.5	1662.7	279.4	0.0	0.0	0.2	1880.9	4494.4	5219.6
1931-32	4455.5	3982.6	3460.5	2727.7	779.0	0.0	0.0	0.0						
							DUNCAN							
1928-29	1726.8	1726.8	1529.1	1468.0	1345.6	1101.0	611.6	227.5	249.6	263.0	290.7	578.1	1250.5	1707.7
1929-30	1712.6	1651.5	1345.6	1223.3	1101.0	734.0	244.7	183.5	0.0	32.8	113.8	395.1	932.4	1345.6
1930-31	1468.0	1468.0	1284.5	1101.0	978.6	489.3	183.5	61.2	0.0	11.7	0.0	384.6	966.7	1223.3
1931-32	1345.6	1345.6	1101.0	856.3	367.0	0.0	0.0	0.0						
							COMPOSITE							
1928-29	19119.2	19119.2	18348.3	17710.2	16266.5	13301.9	8315.5	4180.0	3182.5	2932.2	3057.5	6719.3	15186.8	18716.0
1929-30	19103.8	18827.8	16577.9	14145.5	11170.2	8219.8	2986.6	500.6	0.0	289.4	1760.3	6319.8	13225.6	17449.6
1930-31	18369.3	18583.4	17306.5	15154.5	11935.2	8111.7	3730.6	798.3	0.0	11.7	0.2	3912.6	10437.9	12690.8
1931-32	12118.5	11533.0	9672.6	7618.2	3890.8	620.7	0.0	0.0						

TABLE 4M
(Metric Units)
MICA
ASSURED AND VARIABLE REFILL CURVES,
DISTRIBUTION FACTORS AND FORECAST ERRORS,
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2018 - 19 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	0.0	1441.8	1878.3	2037.3	2076.9	2064.0	2035.6	2051.7	2113.1	2268.0	3670.9	6620.5	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							5032.7	4589.3	4449.9	4430.8	4538.0	5790.6	7306.3	8634.5
1929-30							2528.8	1986.9	1826.6	1852.1	2243.8	4313.4	6596.5	"
1930-31							3160.5	2641.1	2468.9	2441.2	2670.7	4359.6	6783.2	"
1931-32							1160.2	657.2	502.5	476.8	773.1	2736.8	6165.7	"
1932-33							931.2	515.0	402.7	371.9	571.3	2490.4	5759.1	"
1933-34							0.0	0.0	0.0	0.0	0.0	1871.4	6388.1	"
1934-35							1771.6	1309.9	1227.0	1245.1	1425.6	3172.5	6018.1	"
1935-36							1337.1	876.1	766.0	734.2	976.2	3140.0	6702.2	"
1936-37							5000.4	4506.4	4330.7	4285.0	4509.8	5820.5	7385.3	"
1937-38							1843.3	1382.1	1226.7	1212.0	1448.4	3283.1	6395.2	"
1938-39							2564.8	2212.2	2074.5	2110.2	2390.8	4298.2	7322.7	"
1939-40							2030.2	1587.4	1492.7	1513.7	1839.6	3803.0	6723.7	"
1940-41							3613.9	3145.3	3020.3	3039.9	3481.0	5281.7	7340.5	"
1941-42							2994.1	2535.2	2390.1	2352.9	2547.2	4188.6	6839.5	"
1942-43							3403.2	2889.2	2736.3	2698.6	3078.8	4812.7	6990.9	"
1943-44							5259.2	4727.1	4584.4	4561.0	4735.4	6087.6	7734.4	"
1944-45							4875.3	4433.7	4325.1	4327.8	4456.0	5702.3	7459.9	"
1945-46							426.2	0.0	0.0	0.0	0.0	2001.3	6155.4	"
1946-47							704.9	299.7	211.9	208.9	504.2	2636.7	6325.9	"
1947-48							579.6	124.0	0.0	0.0	138.5	2138.3	6042.6	"
1948-49							4734.7	4220.9	4025.9	3987.0	4183.0	5491.9	7972.5	"
1949-50							1450.3	898.9	715.1	660.1	876.6	2677.3	5570.9	"
1950-51							1429.1	994.3	889.1	877.4	1164.8	2967.7	6474.9	"
1951-52							2425.1	1887.1	1718.5	1649.3	1857.5	3687.5	6843.4	"
1952-53							3113.8	2620.3	2474.2	2436.1	2590.0	4065.8	6760.7	"
1953-54							360.6	0.0	0.0	0.0	3.7	1934.0	5501.2	"
1954-55							2221.5	1796.0	1691.1	1684.2	1904.2	3507.9	5987.3	"
1955-56							1115.4	645.7	491.3	442.3	668.9	2718.9	6261.3	"
1956-57							1528.4	1041.0	922.1	903.0	1130.6	2928.8	7088.0	"
1957-58							1121.0	665.2	562.5	556.6	823.5	2677.3	6494.0	"
DISTRIBUTION FACTORS							0.9760	0.9790	0.9750	0.9820	0.9650	0.7920	0.5060	N/A
FORECAST ERRORS (hm^3)							1780.9	1276.6	1113.7	1028.1	1028.1	982.1	971.3	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	271.84	566.34	849.50
VARIABLE REFILL CURVES					98.68	km^3	85.0	85.0	85.0	85.0	85.0	85.0	566.3	770.2
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	85.0	85.0	85.0	85.0	85.0	85.0	339.8	651.3
					135.69	km^3	85.0	85.0	85.0	85.0	85.0	85.0	339.8	651.3
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							1031.5	55.0	0.0	0.0				

TABLE 5M
(Metric Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES,
DISTRIBUTION FACTORS AND FORECAST ERRORS,
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2018 - 19 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	0.0	0.0	0.0	0.0	0.0	1257.6	1619.2	1818.6	2016.0	2429.0	5547.9	8580.7	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							6565.2	6021.6	5741.2	5569.0	5888.7	7823.0	8736.1	8757.8
1929-30							2446.4	2021.4	2125.6	2137.6	2802.8	6327.9	8240.9	"
1930-31							3680.2	3135.8	2907.1	2818.0	3350.9	5973.4	8267.1	"
1931-32							0.0	0.0	0.0	0.0	555.9	4061.6	7500.1	"
1932-33							918.5	798.8	828.4	819.6	1349.1	4414.6	7339.8	"
1933-34							0.0	0.0	0.0	0.0	386.6	5555.5	8549.6	"
1934-35							1560.0	1413.2	1678.6	1737.6	2198.3	4939.9	7617.2	"
1935-36							1705.3	1322.4	1207.6	1129.1	1549.9	4912.5	8349.3	"
1936-37							7321.2	6668.7	6362.4	6119.9	6491.8	8249.0	8757.8	"
1937-38							2419.2	2195.3	2235.2	2314.5	2871.8	5638.2	8100.7	"
1938-39							3011.5	2588.5	2387.4	2301.3	3021.6	6192.8	8757.8	"
1939-40							2157.9	1924.0	2041.4	2255.5	2941.8	5652.9	8437.8	"
1940-41							5233.5	4809.8	4672.5	4881.2	5960.2	8519.3	8757.8	"
1941-42							5163.3	4751.1	4597.4	4428.3	4933.3	7302.1	"	"
1942-43							6290.0	5710.1	5493.4	5286.9	6018.6	8513.4	"	"
1943-44							8573.1	8052.5	7802.9	7567.6	7985.9	8757.8	"	"
1944-45							7002.4	6592.6	6405.0	6301.7	6610.0	8292.0	"	"
1945-46							242.7	376.5	287.5	236.3	1056.2	4366.2	7837.7	"
1946-47							1762.5	1663.0	1670.5	1725.3	2349.7	5393.3	8080.1	"
1947-48							1224.0	1349.8	1339.5	1191.7	1684.5	4646.6	7904.5	"
1948-49							5494.6	4994.7	4831.8	4689.2	5267.5	7864.1	8757.8	"
1949-50							1403.4	1119.6	1158.2	1159.7	1660.0	4454.3	7036.7	"
1950-51							2145.7	1943.6	2043.9	1958.5	2564.3	5317.9	8253.6	"
1951-52							2305.7	1925.2	1972.4	1906.9	2368.6	5447.6	8400.9	"
1952-53							3919.7	3449.2	3318.1	3177.2	3552.5	6093.5	8271.2	"
1953-54							0.0	0.0	12.5	25.9	741.1	3735.7	7058.9	"
1954-55							1595.9	1447.9	1542.8	1482.6	2010.9	4634.6	6986.3	"
1955-56							870.7	619.0	664.0	651.5	1229.7	4634.3	7910.6	"
1956-57							1038.8	741.1	766.5	725.9	1286.9	4284.2	8691.1	"
1957-58							546.8	285.0	422.5	586.7	1310.6	4356.7	7999.6	"
DISTRIBUTION FACTORS							0.9730	0.9760	0.9700	0.9740	0.9510	0.7420	0.4670	N/A
FORECAST ERRORS (hm^3)							3633.4	2679.8	2334.5	1981.0	1981.0	1769.4	1662.2	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	269.01	934.46	1699.01
VARIABLE REFILL CURVES					98.68	km^3	141.58	141.58	141.58	141.58	141.58	141.58	877.82	1415.84
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	141.58	141.58	141.58	141.58	141.58	141.58	877.82	1415.84
					135.69	km^3	141.58	141.58	141.58	141.58	141.58	141.58	877.82	1415.84
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							1006.3	91.7	0.0	0.0				

TABLE 6M
(Metric Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES,
DISTRIBUTION FACTORS AND FORECAST ERRORS,
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2018 - 19 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	0.0	3.2	78.3	121.1	148.5	173.5	196.0	230.5	256.9	295.1	679.7	1232.4	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							853.9	812.3	832.6	827.4	868.1	1127.1	1457.7	1726.8
1929-30							849.9	807.4	827.2	821.1	880.3	1176.6	1486.6	"
1930-31							713.9	674.5	703.2	709.5	765.1	1054.2	1457.7	"
1931-32							41.1	5.6	51.6	71.4	157.8	609.2	1237.0	"
1932-33							0.0	0.0	0.0	0.0	0.0	183.5	899.1	"
1933-34							81.7	88.6	147.3	182.0	295.3	803.2	1414.4	"
1934-35							201.1	178.4	234.4	238.8	298.0	701.0	1225.0	"
1935-36							143.1	106.2	134.6	135.8	203.1	692.9	1363.5	"
1936-37							696.5	652.8	678.0	672.8	724.2	1017.8	1411.9	"
1937-38							188.1	168.1	207.5	228.3	302.2	728.8	1307.2	"
1938-39							316.6	290.9	322.2	330.8	408.3	827.2	1421.5	"
1939-40							284.5	270.8	321.0	352.8	437.0	834.3	1387.5	"
1940-41							490.5	470.0	510.1	546.1	657.4	1028.3	1444.2	"
1941-42							476.1	461.4	501.1	509.9	581.6	939.0	1396.8	"
1942-43							506.0	473.4	509.9	514.8	609.7	992.1	1378.7	"
1943-44							868.8	838.4	870.3	869.8	927.5	1193.0	1533.8	"
1944-45							679.4	649.8	684.3	685.3	729.8	1019.5	1431.8	"
1945-46							0.0	0.0	0.0	0.0	0.0	466.3	1231.4	"
1946-47							"	"	"	"	74.9	574.0	1255.1	"
1947-48							97.4	70.0	113.5	115.0	175.9	616.3	1291.6	"
1948-49							651.0	611.2	639.5	636.6	698.5	1033.9	1541.6	"
1949-50							162.0	123.3	158.1	156.6	221.4	625.6	1133.3	"
1950-51							0.0	0.0	0.0	0.0	78.0	539.0	1212.0	"
1951-52							237.3	203.8	246.6	247.6	311.0	765.3	1336.6	"
1952-53							230.5	203.6	241.5	246.1	302.4	703.2	1244.6	"
1953-54							0.0	0.0	0.0	0.0	0.0	367.5	1072.1	"
1954-55							73.6	45.5	83.4	90.5	159.3	568.6	1071.6	"
1955-56							0.0	0.0	0.0	0.0	0.0	491.5	1214.0	"
1956-57							122.3	79.0	112.3	117.9	189.4	612.9	1381.4	"
1957-58							0.0	0.0	0.0	0.0	6.4	466.1	1263.4	"
DISTRIBUTION FACTORS							0.9740	0.9800	0.9760	0.9790	0.9570	0.7510	0.4810	N/A
FORECAST ERRORS (hm^3)							312.2	255.2	256.9	229.5	229.5	212.6	190.8	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	14.16	22.65
VARIABLE REFILL CURVES					98.68	km^3	2.83	2.83	2.83	2.83	2.83	2.83	50.97	70.79
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	2.83	2.83	2.83	2.83	2.83	2.83	50.97	70.79
					135.69	km^3	2.83	2.83	2.83	2.83	2.83	2.83	50.97	70.79
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							28.9	15.4	0.0	0.0				

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8634.5	8634.5	8634.5	8387.9	8387.9	8151.1	7846.2	7571.0	7266.2	7266.2	7266.2	8100.7	8634.5	8634.5
1929-30	"	"	"	"	"	"	7719.5	7330.3	6898.7	6898.7	6898.7	7103.5	8032.2	"
1930-31	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8151.1	8634.5	"
1931-32	"	"	"	"	"	"	6601.7	5151.1	3601.9	3601.9	3601.9	5660.2	8443.5	"
1932-33	"	"	"	"	"	"	6584.5	5168.4	"	"	"	4065.0	8030.7	"
1933-34	"	"	"	"	"	"	"	"	"	3717.6	4855.0	8247.0	8634.5	"
1934-35	"	"	"	"	"	"	"	"	"	3601.9	3601.9	4694.0	8156.5	"
1935-36	"	"	"	"	"	"	6601.7	5151.1	"	"	4074.8	6918.3	8634.5	"
1936-37	"	"	"	"	"	"	7687.0	7268.4	6804.5	6804.5	6804.5	7344.2	"	"
1937-38	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	4855.0	"	"
1938-39	"	"	"	"	"	"	6984.3	5929.1	4762.3	4762.3	4928.9	7863.9	8367.4	"
1939-40	"	"	"	"	"	"	7372.6	6644.2	5866.0	5866.0	5866.0	8089.2	8390.9	"
1940-41	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8603.5	8634.5	"
1941-42	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	4784.6	8025.6	"
1942-43	"	"	"	"	"	"	"	"	"	3682.4	4190.8	5398.7	8035.6	"
1943-44	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8615.7	8634.5	"
1944-45	"	"	"	"	"	"	6947.6	5859.6	4656.4	4656.4	4656.4	5424.1	"	"
1945-46	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	6636.4	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	3677.2	6309.3	"	"
1947-48	"	"	"	"	"	"	6601.7	5151.1	"	"	3601.9	5695.4	"	"
1948-49	"	"	"	"	"	"	6584.5	5168.4	"	"	3667.2	5947.2	8629.4	"
1949-50	"	"	"	"	"	"	"	"	"	"	3601.9	3782.9	7648.1	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	6012.5	8634.5	"
1951-52	"	"	"	"	"	"	6601.7	5151.1	"	"	3858.5	6193.6	"	"
1952-53	"	"	"	"	"	"	6584.5	5168.4	"	"	3601.9	4729.0	8297.4	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	5247.5	6782.5	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	3601.9	7467.0	"
1955-56	"	"	"	"	"	"	6601.7	5151.1	"	"	"	5589.7	8634.5	"
1956-57	"	"	"	"	"	"	6584.5	5168.4	"	"	"	7300.9	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6394.9	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8757.8	8757.8	8757.8	8449.6	8449.6	7887.1	7807.3	7735.2	7655.7	7655.7	7655.7	7850.6	8757.8	8757.8
1929-30	"	"	"	"	"	"	7689.9	7511.8	7314.6	7314.6	7314.6	7316.1	"	"
1930-31	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8757.8	"	"
1931-32	"	"	"	"	"	"	6670.7	5533.5	4317.3	4317.3	4317.3	4996.7	"	"
1932-33	"	"	"	"	"	"	6657.2	5546.9	"	"	"	4317.3	7856.5	"
1933-34	"	"	"	"	"	"	"	"	"	4352.7	5556.2	5960.2	8757.8	"
1934-35	"	"	"	"	"	"	"	"	"	4317.3	4317.3	5023.4	"	"
1935-36	"	"	"	"	"	"	6670.7	5533.5	"	"	4596.9	7616.5	"	"
1936-37	"	"	"	"	"	"	7659.3	7454.1	7226.5	7226.5	7226.5	7226.5	"	"
1937-38	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	4858.9	"	"
1938-39	"	"	"	"	"	"	7002.7	6203.6	5319.2	5319.2	5346.8	5862.5	"	"
1939-40	"	"	"	"	"	"	7362.6	6872.7	6348.4	6348.4	6348.4	7683.3	"	"
1940-41	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8359.1	"	"
1941-42	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	4819.1	7141.4	"
1942-43	"	"	"	"	"	"	"	"	"	"	4974.4	6102.3	8757.8	"
1943-44	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	7887.1	"	"
1944-45	"	"	"	"	"	"	6971.1	6143.7	5227.6	5227.6	5227.6	5308.9	"	"
1945-46	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	4596.9	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	5409.7	"	"
1947-48	"	"	"	"	"	"	6670.7	5533.5	"	"	"	4601.3	"	"
1948-49	"	"	"	"	"	"	6657.2	5546.9	"	"	4334.9	7132.6	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	4317.3	4317.3	7332.5	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	5232.1	8757.8	"
1951-52	"	"	"	"	"	"	6670.7	5533.5	"	"	4565.8	6923.9	"	"
1952-53	"	"	"	"	"	"	6657.2	5546.9	"	"	4317.3	4912.3	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	5165.5	7097.1	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	4317.3	8109.5	"
1955-56	"	"	"	"	"	"	6670.7	5533.5	"	"	"	5831.5	8757.8	"
1956-57	"	"	"	"	"	"	6657.2	5546.9	"	"	"	6475.4	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6488.6	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	1726.8	1726.8	1726.8	1726.8	1726.8	1233.3	1022.7	832.6	832.6	832.6	832.6	1049.8	1723.1	1726.8
1929-30	"	"	"	"	"	"	999.9	789.3	789.3	789.3	789.3	873.7	1411.7	"
1930-31	"	"	"	"	"	"	955.9	705.4	705.4	705.4	705.4	1043.5	1625.8	"
1931-32	"	"	"	"	"	"	678.4	228.0	160.7	160.7	163.7	677.7	1533.5	"
1932-33	"	"	"	"	"	"	669.6	"	"	"	160.7	319.5	1367.2	"
1933-34	"	"	"	"	"	"	"	"	"	220.7	411.0	1033.0	1608.4	"
1934-35	"	"	"	"	"	"	"	"	"	160.7	160.7	440.9	1235.3	"
1935-36	"	"	"	"	"	"	678.4	"	"	169.5	311.9	956.4	1707.2	"
1936-37	"	"	"	"	"	"	917.0	631.5	631.5	631.5	631.5	818.6	1426.6	"
1937-38	"	"	"	"	"	"	709.8	283.6	237.3	237.3	237.3	612.6	1430.8	"
1938-39	"	"	"	"	"	"	697.5	266.7	214.1	214.1	292.9	900.3	1411.4	"
1939-40	"	"	"	"	"	"	736.7	309.5	272.6	272.6	272.6	787.1	1458.9	"
1940-41	"	"	"	"	"	"	842.6	489.6	489.6	489.6	489.6	800.3	1417.6	"
1941-42	"	"	"	"	"	"	797.8	405.2	403.9	403.9	403.9	681.4	1227.2	"
1942-43	"	"	"	"	"	"	805.7	419.3	419.3	465.1	586.7	884.9	1381.6	"
1943-44	"	"	"	"	"	"	1009.2	800.5	800.5	800.5	800.5	945.9	1511.0	"
1944-45	"	"	"	"	"	"	933.4	662.3	662.3	662.3	662.3	891.1	1523.5	"
1945-46	"	"	"	"	"	"	669.6	228.0	160.7	160.7	193.8	883.0	1708.7	"
1946-47	"	"	"	"	"	"	"	"	"	"	222.2	820.1	1600.8	"
1947-48	"	"	"	"	"	"	678.4	"	"	"	160.7	688.2	1647.3	"
1948-49	"	"	"	"	"	"	900.3	599.4	599.4	599.4	651.3	1230.6	1726.8	"
1949-50	"	"	"	"	"	"	669.6	228.0	160.7	160.7	160.7	258.1	1166.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	713.7	1371.6	"
1951-52	"	"	"	"	"	"	678.4	"	"	"	279.2	791.5	1525.9	"
1952-53	"	"	"	"	"	"	669.6	"	"	"	160.7	461.9	1206.7	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	617.8	1319.2	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	160.3	1131.8	"
1955-56	"	"	"	"	"	"	678.4	"	"	"	"	722.7	1613.0	"
1956-57	"	"	"	"	"	"	669.6	"	"	"	174.2	977.4	1726.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	162.2	909.9	"	"

TABLE 10M
(Metric Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	8315.5	4297.9	4119.8	4392.1	4992.0	9898.5	16451.7	19119.2
1929-30	"	"	"	"	"	"	5403.8	4235.8	3894.7	4131.1	4967.8	"	16087.9	"
1930-31	"	"	"	"	"	"	6637.6	4297.9	4119.8	4392.1	4992.0	"	16138.0	"
1931-32	"	"	"	"	"	"	2207.6	764.3	554.2	548.3	1486.8	7407.6	14902.7	"
1932-33	"	"	"	"	"	"	2066.6	1329.2	1231.1	1191.5	1920.3	6991.2	13998.0	"
1933-34	"	"	"	"	"	"	2119.5	235.4	147.3	182.0	681.6	8099.0	16188.2	"
1934-35	"	"	"	"	"	"	3532.6	2901.4	3066.3	3143.4	3784.6	8553.3	14860.4	"
1935-36	"	"	"	"	"	"	3185.5	2304.7	2108.2	1999.1	2729.2	8732.2	16220.2	"
1936-37	"	"	"	"	"	"	8315.5	4297.9	4119.8	4392.1	4992.0	9898.5	16451.7	"
1937-38	"	"	"	"	"	"	4450.6	3585.0	3252.8	3456.3	4114.7	8754.7	15746.3	"
1938-39	"	"	"	"	"	"	5673.9	4297.9	4084.4	4340.3	4989.8	9898.5	16451.7	"
1939-40	"	"	"	"	"	"	4472.6	3738.9	3560.8	3792.7	4541.1	"	16308.8	"
1940-41	"	"	"	"	"	"	8069.9	4297.9	4119.8	4392.1	4992.0	"	16451.7	"
1941-42	"	"	"	"	"	"	7985.2	"	"	"	"	9169.6	14989.1	"
1942-43	"	"	"	"	"	"	8209.8	"	"	"	"	9898.5	16451.7	"
1943-44	"	"	"	"	"	"	8315.5	"	"	"	"	"	"	"
1944-45	"	"	"	"	"	"	"	"	"	"	"	9659.4	"	"
1945-46	"	"	"	"	"	"	2066.6	447.0	287.5	236.3	1056.2	6833.8	15224.5	"
1946-47	"	"	"	"	"	"	2822.9	1978.1	1882.4	1934.3	2928.8	8604.0	15656.5	"
1947-48	"	"	"	"	"	"	2352.9	1543.8	1453.0	1306.7	1983.7	7355.9	15197.5	"
1948-49	"	"	"	"	"	"	8315.5	4297.9	4119.8	4392.1	4992.0	9898.5	16451.7	"
1949-50	"	"	"	"	"	"	3015.7	2141.8	2031.4	1976.4	2697.4	7252.7	13740.8	"
1950-51	"	"	"	"	"	"	3603.6	2953.3	2707.7	2835.9	3671.9	8738.8	15940.6	"
1951-52	"	"	"	"	"	"	4888.8	4016.1	3697.8	3716.9	4505.2	9798.1	16271.8	"
1952-53	"	"	"	"	"	"	6496.0	4274.0	4031.0	4289.9	4857.7	9045.1	16098.4	"
1953-54	"	"	"	"	"	"	2066.6	162.2	12.5	25.9	744.7	6037.2	13632.2	"
1954-55	"	"	"	"	"	"	3891.1	3289.5	3317.3	3257.4	4074.3	7985.5	14045.2	"
1955-56	"	"	"	"	"	"	2150.6	1280.1	1155.3	1093.9	1898.6	7844.8	15385.9	"
1956-57	"	"	"	"	"	"	2689.5	1861.1	1800.9	1746.9	2591.7	7825.9	16451.7	"
1957-58	"	"	"	"	"	"	2156.2	965.7	985.0	1143.3	2140.5	7500.1	15744.1	"

TABLE 11M
(Metric Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2018 - 19 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19119.2	18348.3	17710.2	16266.7	13301.9	8315.5	4180.0	3182.8	2932.0	3057.5	6719.3	15186.8	18716.0
1929-30	19103.8	18827.8	16455.8	14145.5	11170.2	8219.8	2986.6	500.6	0.0	289.4	1760.3	6319.8	13225.6	17449.6
1930-31	18369.3	18583.4	17245.3	15154.5	11935.2	8111.5	3730.6	798.3	0.0	11.7	0.2	3912.6	10437.9	12690.8
1931-32	12118.5	11533.0	9672.6	7618.2	3890.8	620.7	0.0	0.0	4.2	297.5	1127.4	5836.1	14248.8	18630.4
1932-33	18952.3	19119.2	16972.3	15540.1	15595.9	12631.6	7470.7	3438.7	1231.1	1072.8	1581.0	5862.3	13998.0	18891.7
1933-34	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7657.1	3784.2	1883.4	1482.9	3003.7	8099.0	15197.3	18631.3
1934-35	19016.2	18818.8	16577.9	15038.8	15906.6	12631.6	7495.2	3824.8	3001.7	2701.3	3045.5	7572.5	14860.4	19119.2
1935-36	19119.2	19067.3	18099.9	16287.0	13851.9	10186.4	4848.4	2202.4	1236.8	1020.7	2139.3	8732.2	16220.2	18891.7
1936-37	19071.7	18815.3	16577.9	14434.2	11445.9	7957.1	2923.2	453.1	0.0	21.3	128.9	3781.0	11126.4	14629.9
1937-38	14611.1	14278.4	12558.6	11014.1	9506.3	7518.6	4450.6	3544.4	1910.3	1663.4	1438.4	6317.9	14083.1	18829.5
1938-39	18773.5	18693.5	17256.4	16171.8	13944.6	11437.9	6178.9	4235.6	3302.4	3381.2	3463.9	9898.5	14763.0	18891.7
1939-40	19104.5	18848.6	16720.3	15491.4	14153.1	12631.6	7434.7	3738.9	3114.5	3332.0	4101.0	9898.5	14809.0	17703.6
1940-41	17922.1	17730.3	16577.9	16398.3	13969.4	10912.3	6981.1	3783.4	3186.5	3716.9	4747.4	7497.1	11742.5	13981.3
1941-42	13600.9	13266.0	12417.5	13554.2	12482.6	12631.6	8033.2	4297.9	2670.7	2389.8	2151.8	6810.6	12585.3	18568.7
1942-43	19033.3	19012.5	17346.9	15707.2	15114.4	12631.6	8227.9	4297.9	3266.5	3441.9	3533.1	6867.6	12747.0	18891.7
1943-44	19119.2	19119.2	18182.6	17421.3	15910.7	12629.8	8275.9	4208.4	2955.7	2826.6	2872.8	5892.9	11185.6	13066.1
1944-45	12696.9	12198.5	10419.1	8949.2	5782.8	2472.8	499.4	0.0	0.0	2.0	0.0	4475.8	11735.1	15720.4
1945-46	15301.3	14843.3	13043.3	11391.4	9378.3	7277.4	2066.6	447.0	0.0	0.0	692.4	6678.7	15169.4	18891.7
1946-47	19119.2	19081.8	18348.3	17421.3	16191.1	12631.6	7268.4	3242.5	1882.4	1934.3	2928.8	8604.0	15656.5	19119.2
1947-48	19119.2	19062.9	18348.3	17421.3	16191.1	12631.6	7333.2	3089.6	1453.0	1193.7	1687.9	7355.9	15197.5	19119.2
1948-49	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	8315.5	4297.9	3335.0	3334.2	3683.8	9898.5	15594.1	18136.6
1949-50	18877.7	18776.2	16725.9	15475.5	15657.0	12631.6	7264.2	3197.0	2024.8	1875.1	2044.6	5509.7	13740.8	19119.2
1950-51	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7465.1	3523.3	2440.2	2496.0	2832.7	8734.6	15155.0	18969.2
1951-52	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7266.9	4016.1	2946.4	2785.2	3569.1	9372.4	16008.6	18891.7
1952-53	19119.2	19034.3	17637.1	15978.5	13558.1	10430.3	6655.2	4274.0	3254.0	2865.0	2435.8	7028.6	14251.0	18891.7
1953-54	19096.0	19119.2	18348.3	17421.3	16191.1	12631.6	7412.0	3521.6	1355.4	526.5	606.0	6037.2	13632.2	19119.2
1954-55	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7529.2	3584.0	2613.9	2532.2	2235.2	5069.1	14045.2	18891.7
1955-56	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7396.1	3176.4	1155.3	1074.5	1898.6	7844.8	15385.9	18891.7
1956-57	19033.3	19119.2	18348.3	17421.3	16191.1	12631.6	7316.3	3275.8	1800.9	1722.2	2175.0	7825.9	16421.6	18891.7
1957-58	19009.1	18804.3	16940.7	16178.9	14835.2	12631.6	7388.2	3474.7	1205.9	1143.3	1606.7	7500.1	15744.1	18891.7
Max	19119.2	19119.2	18348.3	17710.2	16266.7	13301.9	8315.5	4297.9	3335.0	3716.9	4747.4	9898.5	16421.6	19119.2
Median	19083.8	19023.4	17301.6	16175.3	15355.1	12631.6	7324.8	3522.5	1896.8	1798.6	2163.4	6948.1	14507.0	18891.7
Average	18104.1	17986.2	16642.0	15462.4	13875.6	10860.4	6206.2	3013.6	1880.5	1802.2	2218.3	7065.1	14138.5	17970.9
Min	12118.5	11533.0	9672.6	7618.2	3890.8	620.7	0.0	0.0	0.0	0.0	0.0	3781.0	10437.9	12690.8

TABLE 12M
(Metric Units)
COMPARISON OF RECENT ASSURED OPERATING PLAN STUDIES

	2010-11	2011-12 through 2013-14 1/	2014-15	2015-16 through 2016-17 3/	2017-18 through 2018-19 4/
MICA TARGET OPERATION (hm^3 or m^3/s)					
AUG 15	8414.3	8230.9	8267.6	8267.6	8548.7
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	8387.9	8387.9	8387.9	8328.5	8328.5
NOV	594.7	594.7	623.0	594.7	538.0
DEC	707.9	707.9	623.0	481.4	651.3
JAN	764.6	679.6	679.6	679.6	679.6
FEB	594.7	594.7	594.7	736.2	651.3
MAR	594.7	481.4	707.9	707.9	283.2
APR 15	623.0	566.3	481.4	594.7	424.8
APR 30	283.2	283.2	283.2	283.2	283.2
MAY	226.5	226.5	226.5	226.5	226.5
JUN	226.5	226.5	283.2	226.5	226.5
JUL	8482.9	8482.9	8482.9	8407.0	8407.0
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm^3)					
1928 AUG 31	19069.0	19118.7	19119.2	19119.2	19119.2
1928 DEC	12443.4	12732.1	12923.2	12459.3	13301.9
1929 APR15	2564.5	2653.1	2637.9	2506.5	2932.0
1929 JUL	17696.7	17933.1	18351.7	18559.7	18716.0
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm^3) 2/					
AUG 31	18197.7	18013.8	18121.4	18142.3	18070.3
DEC	11286.0	11327.8	11363.5	10985.5	11069.5
APR15	2061.6	2222.9	2175.9	1752.5	1984.2
JUL	17784.1	17486.1	17811.0	17869.5	18077.2
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.3	0.1	0.0	0.0	-0.5
U.S. Dependable Peaking Capacity 5/	-19.1	-22.9	-3.9	-2.1	6.9 / 35.3
U.S. Average Annual Usable Secondary Energy	16.0	21.6	21.3	17.6	22.7
BCH Firm Energy	34.4	43.6	44.0	24.0	18.6
BCH Dependable Peaking Capacity	43.8	41.7	47.8	28.2	37.2
BCH Average Annual Usable Secondary Energy	-20.8	-13.9	-33.4	-16.2	-24.1
COORDINATED HYDRO LOAD (MW)					
AUG 15	11138	10969	11187	11367	12028
AUG 31	11167	11104	10971	10944	11399
SEP	11025	11081	9756	9822	10207
OCT	9958	9920	9758	10051	9233
NOV	11333	11458	11821	12152	11434
DEC	13369	13316	13836	13744	13523
JAN	13076	12878	13323	13933	13862
FEB	11902	11721	13179	12876	13006
MAR	10967	10501	12022	11269	11264
APR 15	10241	9786	10476	10894	9583
APR 30	12475	11502	11012	11600	10684
MAY	13493	13287	12198	12166	12344
JUN	14080	13867	12208	11291	11314
JUL	12725	12531	11954	11812	12256
ANNUAL AVERAGE	12039	11856	11819	11794	11689

1/ The AOP 2013-14 and 2012-13 utilize the same system regulation study as the 2011-12.

2/ Prior to AOP15, average content based on 60 years of modified flows. AOP15 through AOP17 averages based on 70 years of modified flows. AOP18 and AOP19 averages based on 80 years of modified flows.

3/ The AOP 2016-17 utilizes the same Step 1 system regulation studies as used in the AOP 2015-16, so these coordinated hydro loads will be used for the DOP17 TSR unless otherwise agreed.

4/ The AOP 2018-19 utilizes the same Step 1 system regulation studies as used in the AOP 2017-18, so these coordinated hydro loads will be used for the DOP19 TSR unless otherwise agreed.

5/ Due to changes between the AOP 2017-18 and the AOP 2018-19 peak load shape, the period in which the U.S. system dependable peaking capability was determined changed from 15 August 1931 to January 1932.

Appendix A
Project Operating Procedures for the 2018-19
Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months: Apr=Apr.1-30, Apr.15=Apr.1-Apr.15, Apr30=Apr.15-Apr.30; Aug=Aug.1-31, Aug.15=Aug.1-15, Aug.31=Aug.16-31.

Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Canadian Projects					
Mica (1890)	Minimum Flow	3000 cfs	85.0 m^3/s		In place in AOP79, AOP80, AOP84.
Arrow (1831)	Minimum Flow	5000 cfs	141.6 m^3/s		In place in AOP79, AOP80, AOP84.
	Draft Rate Limit	1.0 ft/day	0.30 m/day		
Duncan (1681)	Minimum Flow	100 cfs	2.8 m^3/s		In place in AOP79, AOP80, AOP84.
	Maximum Flow	10000 cfs	283.2 m^3/s		
	Draft Rate Limit	1.0 ft/day	0.30 m/day		
	Other			Remove 5-step logic of Operate to meet IJC orders for Corra Linn.	CRTOC agreement on to remove 5-step logic procedures to implement 1938 IJC order. 2012
Base System					
Hungry Horse (1530)	Minimum Flow	400 cfs	11.3 m^3/s	Minimum project discharge.	In place in AOP79, AOP80, AOP84.
	Maximum Flow	9500 cfs	269.0 m^3/s	Step 1 only	
	Minimum Content			None	
	Other			No VECC limit.	VECC limit not in place in AOP79.
Kerr (1510)	Minimum Flow	1500 cfs	42.5 m^3/s	All periods	In place in AOP80, AOP84.
	Maximum Flow			None	
	Minimum Content	614.7 ksfd	1503.9 hm^3	Jun - Sep	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80.
		2893.0 ft	881.79 m		
		426.3 ksfd	1043 hm^3	May	
		2890.0 ft	880.9 m		
		0.0 ksfd	0 hm^3	Empty Apr 15	FERC, AOP80.
		2883.0 ft	878.74 m		
	Maximum Content	58.6 ksfd 2884.0 ft	143.37 hm^3 879.04 m	March (Included to help meet the Apr 15 FERC requirement.)	In place in AOP80, AOP84.
	Other	0.0 ksfd	0 hm^3	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80.
		2883.0 ft	878.74 m		
Thompson Falls (1490)				None Noted	

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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Noxon Rapids (1480)	Minimum Content				
	For Step I:	116.3 ksfd	284.54 hm^3	May - Aug 31,	In place in AOP84, similar operation in AOP80.
		2331.0 ft	710.49 m		
		112.3 ksfd	274.75 hm^3	Sep - Jan,	
		2330.0 ft	710.18 m		
		78.7 ksfd	192.55 hm^3	Feb,	
		2321.0 ft	707.44 m		
		26.5 ksfd	64.834 hm^3	Mar,	
		2305.0 ft	702.56 m		
		0.0 ksfd	0 hm^3	Empty Apr 15, Apr 30, and for end of CP.	
		2295.0 ft	699.52 m		
	Minimum & Maximum Content For Steps II & III:	116.3 ksfd	284.54 hm^3	All periods	In place in AOP79, AOP84.
		2331.0 ft	710.49 m		
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	4000 cfs	113.3 m^3/s	All periods	In place in AOP80, AOP84.
	Minimum Content	(Dec may fill on restriction, note below)			
		582.4 ksfd	1424.9 hm^3	Jun - Aug 31	In place in AOP80, AOP84.
		2062.5 ft	628.65 m		
		465.7 ksfd	1139.4 hm^3	Sep	
		2060.0 ft	627.89 m		
		190.4 ksfd	465.83 hm^3	Oct	
		2054.0 ft	626.06 m		
		57.6 ksfd	140.92 hm^3	Nov-Apr 15 (empty at end of CP)	
		2051.0 ft	625.14 m		
		190.4 ksfd	465.83 hm^3	Apr 30	
		2054.0 ft	626.06 m		
		279.0 ksfd	682.59 hm^3	May	
		2056.0 ft	626.67 m		
	For Steps I & II:	Optimum to run CP & LT to Jun-Oct SMINs.			
	For Step III:	Keep full at beginning of CP. Often (not always) optimum to run higher than SMIN in CP & LT (except when occasionally drafting below SMIN to meet load).			
		57.6 ksfd	140.9 hm^3	Nov - Mar	
		2051.0 ft	625.14 m		
		458.4 ksfd	1121.5 hm^3	May	
		2059.8 ft	627.8 m		
		582.4 ksfd	1424.9 hm^3	Sep	
		2062.5 ft	628.7 m		
		465.7 ksfd	1139.4 hm^3	Oct	
		2060.0 ft	627.89 m		

Appendix A
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Project Name (Number)	Constraint Type	Requirements English	Metric	Explanation	Source
Albeni Falls (1465) (Continued)	Kokanee Spawning	1.0 ft	0.30 m	Draft limit below Nov. 20th Elevation through Dec. 31st.	In place before AOP80 and supported by minimum contents noted above.
		0.5 ft	0.15 m	If project fills, draft no more than this amount.	
				Dec. 31 - Mar 31, operate between SMIN and URC within above noted draft limits.	
	Other Spill	50 cfs	1.4 m^3/s	All periods	
				None Noted	
Grand Coulee (1280)	Minimum Flow	30000 cfs	849.5 m^3/s	All periods	In place in AOP79, AOP80, AOP84.
	Minimum Content	0.0 ksfd 1208.0 ft	0.0 hm^3 368.20 m	Empty at end of CP.	
	Step I only:	843.7 ksfd 1240.0 ft	2064.2 hm^3 377.95 m	May and June	Retain as a power operation (for pumping).
	Steps II & III only:	868.8 ksfd 1240.0 ft	2125.6 hm^3 378.0 m	May and June	
	Maximum Content				
	Step I only:	2.0 ft	0.61 m	Operating room Sep - Nov	In place in AOP89
		3.0 ft	0.91 m	Operating room Dec - Feb	Retain as a power operation.
	Steps II & III only:	2557.1 ksfd 1288.0 ft	6256.1 hm^3 392.58 m	Aug-Nov	
		2518.3 ksfd 1287.0 ft	6161.2 hm^3 392.28 m	Dec-Feb	
	Draft Rate Limit	1.3 ft/day	0.40 m/day	(bank sloughage)	
		1.5 ft/day	0.46 m/day	(Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo.ave.)	
Chief Joseph (1270)	Other Spill	500 cfs	14.2 m^3/s	All periods	
Wells (1220)	Other Spill	1000 cfs	28.3 m^3/s	All periods	2/1/05 C. Wagers, Douglas With fish ladder
	Fish Spill			None	
Rocky Reach (1200)	Fish Spill/Bypass			None	
	Other Spill	200 cfs	5.7 m^3/s	Aug 31 - Apr 15 (leakage)	
Rock Island (1170)	Fish Spill/Bypass			None	
Wanapum (1165)	Fish Spill/Bypass			None	
	Other Spill	2200 cfs	62.3 m^3/s	All periods	With fish ladder

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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Spill/Bypass			None	
	Other Spill	2200 cfs	62.3 m^3/s	All periods	With fish ladder
Brownlee (767)	Minimum Flow	0 cfs	0.0 m^3/s	All years, all periods in CP & LT studies.	4-04 C. Henriksen
	Downstream Minimum Flow	6500 cfs	184.1 m^3/s	All periods for navigation requirement downstream at Hells Canyon (project #762). Draft Brownlee to help meet this requirement in CP and LT studies.	
	Power Operation			Agree to use similar “historic” power operation (rule curves) provided by IPC and used in AOP since AOP97 for CP.	2-1-91 PNCA submittal
				Optimizer was used in the Step I critical period study to get a starting point for Brownlee operations. Results were then modified to follow the general shape of the "historic" shape for power with the exception of going empy at the end of the critical period. To the extent possible, CRC1 is used in every year. Step II/III studies will use the same operation, except as needed to start critical periods full and end empty.	5-12 P. Kingsbury, T. Downen (BPA)
Oxbow (765)	Other Spill	100 cfs	2.8 m^3/s	All periods	
Ice Harbor (502)	Fish Spill/Bypass			None	
	Other Spill	740 cfs	21.0 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow			None	
	Other	204.8 ksfd 440.0 ft	83.7 hm^3 134.11 m	Run at all periods	
McNary (488)	Other Spill	3475 cfs	98.4 m^3/s	All periods	
	Incremental Spill			None	
John Day (440)	Fish Spill/Bypass			None	
	Other Spill	800 cfs	22.7 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs 12500 cfs	1415.8 m^3/s 354.0 m^3/s	Mar - Nov Dec - Feb	

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Project		Requirements			
Name (Number)	Constraint Type	English	Metric	Explanation	Source
John Day (440)	Other				
(Continued)	Step I:	269.7 ksfd	659.8 hm^3	June - Aug 15	In place AOP80
		268.0 ft	81.69 m		
		242.5 ksfd	593.3 hm^3	Aug 31 - Sep	
		267.0 ft	81.38 m		
		153.7 ksfd	376.0 hm^3	Oct - Mar	
		263.6 ft	80.35 m		
		114.9 ksfd	281.1 hm^3	Apr - May	
		262.0 ft	79.86 m		
	Steps II & III:	190.0 ksfd	464.8 hm^3	Use JDA as run-of-river plant.	
		265.0 ft	80.77 m		
The Dalles (365)	Fish Spill/Bypass			None	
	Other Spill	1300 cfs	36.8 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs	1415.8 m^3/s	Mar - Nov	
		12500 cfs	354.0 m^3/s	Dec - Feb	
Bonneville (320)	Fish Spill/Bypass			None	
	Other Spill	8040 cfs	227.7 m^3/s	All periods	
	Incremental Spill			None	
Kootenay Lake (Corra Linn (1665))	Minimum Flow	5000 cfs	141.6 m^3/s	All periods	BCHydro agreements 1969.
	Other			Remove 5-step logic of Operate to meet IJC orders for Corra Linn.	CRTOC agreement on to remove 5-step logic procedures to implement 1938 IJC order.
Chelan (1210)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	308.5 ksfd	126.1 hm^3	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
		1098.0 ft	334.7 m		
Couer d'Alene L (1341)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79.
	Minimum Content	112.5 ksfd	275.2 hm^3	May - Aug	
		2128.0 ft	648.6 m	Flood control may override these minimum contents.	2-1-00 PNCA submittal
Post Falls (1340)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84.
Other Major Step I Projects					
Libby (1760)	Minimum Flow	4000 cfs	113.3 m^3/s	All periods	
	Other Spill	200 cfs	5.7 m^3/s	All periods	

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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Libby (1760) (Continued)	Minimum Content	By			
		776.9 ksfd	1900.7 hm^3	1929 Dec	2-1-93 PNCA submittal, in plac in AOP99.
		2363.0 ft	720.24 m		
		676.5 ksfd	1655.1 hm^3	1929 Jan	
		2355.0 ft	717.80 m		
		603.6 ksfd	1476.8 hm^3	1929 Feb	
		2349.0 ft	715.98 m		
		2147.7 ksfd	5254.5 hm^3	1929 Jul	
		2443.0 ft	744.63 m		
		652.0 ksfd	1595.2 hm^3	1930 Dec	
		2353.0 ft	717.19 m		
		433.2 ksfd	1059.9 hm^3	1930 Jan	
		2334.0 ft	711.40 m		
		389.3 ksfd	952.5 hm^3	1930 Feb	
		2330.0 ft	710.18 m		
		348.5 ksfd	852.6 hm^3	1930 Mar	
		2326.0 ft	708.96 m		
		297.4 ksfd	727.6 hm^3	1930 Apr 15	
		2321.0 ft	707.44 m		
		444.2 ksfd	1086.8 hm^3	1930 Apr 30	
		2335.0 ft	711.71 m		
		499.1 ksfd	1221.1 hm^3	1930 May	
		2340.0 ft	713.23 m		
		1344.6 ksfd	3289.7 hm^3	1930 Jun	
		2402.0 ft	732.13 m		
		1771.9 ksfd	4335.1 hm^3	1930 Jul	
		2425.0 ft	739.14 m		
		317.8 ksfd	777.5 hm^3	1931 Dec	
		2323.0 ft	708.05 m		
		192.2 ksfd	470.2 hm^3	1931 Jan	
		2310.0 ft	704.09 m		
		103.1 ksfd	252.2 hm^3	1931 Feb-Apr 30	
		2300.0 ft	701.04 m		
		192.2 ksfd	470.2 hm^3	1931 May	
		2310.0 ft	704.09 m		
		676.5 ksfd	1655.1 hm^3	1931 Jun	
		2355.0 ft	717.80 m		
		868.0 ksfd	2123.6 hm^3	1931 Jul	
		2370.0 ft	722.38 m		
		174.4 ksfd	426.7 hm^3	1932 Dec	
		2308.0 ft	703.48 m		
		103.1 ksfd	252.2 hm^3	1932 Jan	
		2300.0 ft	701.04 m		
		0.0 ksfd	0.0 hm^3	Empty at end of CP***	
		2287.0 ft	697.08 m		
		776.9 ksfd	1900.7 hm^3	All Dec	
		2363.0 ft	720.24 m		
		373.1 ksfd	152.5 hm^3	July 1930 - No more than this amount lower than July 1929.	2-1-94 PNCA submittal, in place in AOP00 and AOP01.
		857.1 ksfd	350.3 hm^3	July 1931 - No more than this amount lower than July 1930.	
		March - Implement PNCA 6(c)2(c).			

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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Libby (1760) (Continued)	Max Summer Draft	5 ft	1.5 m		
	Other			Remove 5-step logic of Operate to meet IJC orders for Corra Linn.	CRTOC agreement on to remove 5-step logic procedures to implement 1938 IJC order. 2012
Dworshak (535)	Minimum Flow	1600 cfs	45.3 m^3/s	All periods	2-1-12 PNCA submittal (1500 cfs powerhouse/100 cfs hatchery water supply)
	Maximum Flow	14000 cfs	396.4 m^3/s	All periods (model includes maximum 14000 cfs for all periods, but URC may override.)	2-1-02 PNCA submittal
		25000 cfs	707.9 m^3/s	Up to 25 kcfs for flood control all periods.	
	Start CP at:	497 ksfd	1215.9 hm^3	Aug 15	
	End CP at:	218.4 ksfd	534.3 hm^3	Feb	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements Oct-May and meets target operation Jun-Sep to obtain uniform ouflows Jul-Aug			2-1-05 PNCA submittal
	Target Operation:				Target Elev based on 2010 modified flows and new 80 yr Flood Control data
		780.9 ksfd	1910.5 hm^3	Jul	
		1573.4 ft	479.57 m		
		652.6 ksfd	1596.6 hm^3	Aug 15	for Jul-Aug 15 and Sep based
		1556.8 ft	474.51 m		use 80-yr Median May 2012
		497 ksfd	1215.9 hm^3	Aug 31	
		1535 ft	467.87 m		
		389.4 ksfd	952.7 hm^3	Sep	
		1519 ft	462.99 m		
		1016 ksfd	2485.7 hm^3	Jun	
		1600 ft	487.68 m		
	Other Spill	100 cfs	2.8 m^3/s	All periods	
Lower Granite (520)	Bypass Date			None	
	Other Spill	450 cfs	12.7 m^3/s	Jul	2-1-09 PNCA submittal
		510 cfs	14.4 m^3/s	15-Aug	
		470 cfs	13.3 m^3/s	30-Aug	
		480 cfs	13.6 m^3/s	Sep	
		530 cfs	15.0 m^3/s	Oct	
		410 cfs	11.6 m^3/s	Nov	
		340 cfs	9.6 m^3/s	Dec	
		100 cfs	2.8 m^3/s	Jan	
		130 cfs	3.7 m^3/s	Feb	
		230 cfs	6.5 m^3/s	Mar	
		420 cfs	11.9 m^3/s	15-Apr	
		440 cfs	12.5 m^3/s	Apr 30 - May	
		460 cfs	13.0 m^3/s	Jun	

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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Lower Granite (520) (Continued)	Incremental Spill			Removed	
	Fish Spill				
		17333 cfs	490.8 m³/s	Apr 15 [20 kcfs for 13 days]	2-1-12 PNCA submittal
		20000 cfs	566.3 m³/s	Apr 30 - May [20 kcfs]	2-1-12 PNCA submittal
		19333 cfs	547.4 m³/s	June [20 kcfs through June 21 then 18 kcfs]	2-1-12 PNCA submittal
		18000 cfs	509.7 m³/s	Jul - Aug	2-1-12 PNCA submittal
	Maximum Fish Spill	40000 cfs	1132.7 m³/s	Apr 15 - Jun 21	
		40000 cfs	1132.7 m³/s	Jun - Aug 15	
	Minimum Flow	11500 cfs	325.6 m³/s	All periods	
	Other	224.9 ksfd	550.2 hm³	On MOP Apr - Oct 31.	
		733 ft	223.42 m	On MOP Apr - Oct 31.	
		245.7 ksfd	601.1 hm³	On full pool Nov 30 - Mar 31.	
		738 ft	224.94 m	On full pool Nov 30 - Mar 31.	
Little Goose (518)	Bypass Date			None	
	Other Spill	590 cfs	16.7 m³/s	Jul	2-1-09 PNCA submittal
		620 cfs	17.6 m³/s	15-Aug	
		500 cfs	14.2 m³/s	30-Aug	
		750 cfs	21.2 m³/s	Sep	
		640 cfs	18.1 m³/s	Oct	
		500 cfs	14.2 m³/s	Nov	
		460 cfs	13.0 m³/s	Dec	
		120 cfs	3.4 m³/s	Jan	
		240 cfs	6.8 m³/s	Feb	
		380 cfs	10.8 m³/s	Mar	
		530 cfs	15.0 m³/s	15-Apr	
		580 cfs	16.4 m³/s	Apr 30 - May	
		660 cfs	18.7 m³/s	May	
		590 cfs	16.7 m³/s	Jun	
	Incremental Spill			Removed	
	Fish Spill (% of outflow)	26%		Apr 15 [30%*13/15]	2012 data submittal
		30%		Apr 30	2012 data submittal
		30%		May	2012 data submittal
		30%		Jun - Aug 31	2012 data submittal
	Maximum Fish Spill	30000 cfs	849.5 m³/s	Apr 15 - Apr 31	
		28000 cfs	792.9 m³/s	May	
		30000 cfs	849.5 m³/s	Jun	
		28000 cfs	792.9 m³/s	Jul - Aug 31	
	Minimum Flow	11500 cfs	325.6 m³/s	All periods	
	Other	260.5 ksfd	106.5 hm³	On MOP Apr - Aug 31.	
		633 ft	192.94 m		
		285.0 ksfd	697.3 hm³	On full pool Sep 30 - Mar 31.	
		638 ft	194.46 m		

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Project Name (Number)	Constraint Type	Requirements English	Metric	Explanation	Source
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	790 cfs	22.4 m^3/s	Jul	2-1-09 PNCA submittal
		860 cfs	24.4 m^3/s	15-Aug	
		770 cfs	21.8 m^3/s	30-Aug	
		780 cfs	22.1 m^3/s	Sep	
		840 cfs	23.8 m^3/s	Oct	
		750 cfs	21.2 m^3/s	Nov	
		720 cfs	20.4 m^3/s	Dec	
		450 cfs	12.7 m^3/s	Jan	
		410 cfs	11.6 m^3/s	Feb	
		560 cfs	15.9 m^3/s	Mar	
		770 cfs	21.8 m^3/s	15-Apr	
		780 cfs	22.1 m^3/s	Apr 30 - May	
		840 cfs	23.8 m^3/s	May	
		780 cfs	22.1 m^3/s	Jun	
	Fish Spill	22533 cfs	638.1 m^3/s	Apr 15 [26000*(13/15)]	2-1-12 PNCA submittal
		25000 cfs	707.9 m^3/s	Apr 31	
		22000 cfs	623.0 m^3/s	May	2012 data submittial
		18333 cfs	519.1 m^3/s	June	2012 data submittial
		17000 cfs	481.4 m^3/s	Jul - Aug 31	
	Maximum Fish Spill	26000 cfs	736.2 m^3/s	Apr 15	
		25000 cfs	707.9 m^3/s	Apr 30	
		22000 cfs	623.0 m^3/s	May	
		19000 cfs	538.0 m^3/s	Jun	
		24000 cfs	679.6 m^3/s	Jul - Aug 31	
	Minimum Flow	11500 cfs	325.6 m^3/s	All period	
	Other	180.5 ksfd 537 ft	441.6 hm^3 163.68 m	On MOP Apr - Aug 31.	
		190.1 ksfd 540 ft	465.1 hm^3 164.59 m	On full pool Sep 30 - Mar 31.	
Cushman (2206)	Other Spill	240 cfs	6.8 m^3/s	All periods	2-1-09 PNCA submittal
LaGrande (2188)	Other Spill	30 cfs	0.8 m^3/s	All periods	Submittal
Lower Baker (2025)	Max Storage Limits	67.0 ksfd 442.4 ft	163.9 hm^3 134.84 m	Jul - Aug 31	2-1-12 PNCA submittal
		40.1 ksfd 415.9 ft	98.1 hm^3 126.77 m	Sep	
		34.7 ksfd 409.8 ft	84.9 hm^3 124.91 m	Oct - Dec	
		45.2 ksfd 421.4 ft	110.6 hm^3 128.44 m	Jan - Mar	
		46.7 ksfd 423.0 ft	114.3 hm^3 128.93 m	Apr 15	
		67.0 ksfd 442.4 ft	163.9 hm^3 134.84 m	Apr 30 - Jun	
	Min Storage Limit	30.4 ksfd 404.8 ft	74.4 hm^3 123.38 m	Jun - Sep	
		18.0 ksfd 389.0 ft	44.0 hm^3 118.57 m	Oct - May	

Appendix A
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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Upper Baker (2028)	Max Storage Limits	107.4 ksfd	262.8 hm^3	May - Sep	2-1-12 PNCA submittal
		727.8 ft	221.83 m		
		103.5 ksfd	253.2 hm^3	Oct	
		726.1 ft	221.32 m		
		70.9 ksfd	173.5 hm^3	Nov - Feb	
		711.7 ft	216.93 m		
		84.6 ksfd	207.0 hm^3	Mar - Apr 30	
		718.0 ft	218.85 m		
	Min Storage Limits	100.5 ksfd	245.9 hm^3	Jun - Aug 31	
		724.8 ft	220.92 m		
		91.1 ksfd	222.9 hm^3	Sep	
		720.8 ft	219.70 m		
		40.6 ksfd	99.3 hm^3	Oct	
		695.2 ft	211.90 m		
		25.5 ksfd	62.4 hm^3	Nov - Apr 30	
		685.0 ft	208.79 m		
Timothy (117)	Minimum Content	24.5 ksfd	59.9 hm^3	Oct - May	3-6-01 PNCA submittal
		3180.0 ft	969.26 m		
		31.1 ksfd	76.1 hm^3	Jun - Aug 31	
		3190.0 ft	972.31 m		
		27.8 ksfd	68.0 hm^3	Sep	
		3185.0 ft	970.79 m		
Long Lake (1305)	Minimum Content	50.1 ksfd	122.6 hm^3	Apr - Nov	2-5-02 PNCA submittal
		1535.0 ft	467.87 m		
		19.7 ksfd	48.2 hm^3	Dec - Mar	
		1522.0 ft	463.9 m		
	Draft Rate Limit	1.0 ft/day	0.30 m/day		2-1-03 PNCA submittal
Priest Lake (1470)	Maximum Content	0.0 ksfd	0.0 hm^3	Oct	2-1-03 PNCA submittal
		0.0 ft	0.00 m		
	Max/Min Content	35.5 ksfd	86.9 hm^3	Maintain at or near after runoff through Sep.	
		3.0 ft	0.91 m		
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries.	2-1-06 PNCA submittal
		Fixed ARCs and VRCs			Data came from SCL based on the 80-yr modified streamflow. April 2012
Gorge (2065)	Minimum Flow			Settlement; monthly data, varies by water year.	2-1-12 PNCA submittal

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2018-19

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2018-19

December 2013

1. Introduction

The "Treaty between Canada and The United States of America relating to Cooperative Development of The Water Resources of The Columbia River Basin" (Treaty), dated 17 January 1961, requires that downstream power benefits from the operation of the Treaty storage in Canada (Canadian Treaty Storage) to be determined in advance by the two Entities created by the Treaty. The purpose of this document is to describe the results of the Determination of Downstream Power Benefits for operating year 2018-19 (DDPB19).

2. Procedures

The procedures followed in the benefit studies are those provided in Article VII; Annex A, paragraph 7, and Annex B of the Treaty; in paragraphs VIII, IX, and X of the "Protocol - Annex to Exchange of Notes, Dated January 22, 1964 Between the Governments of Canada And the United States Regarding the Columbia River Treaty" (Protocol), and in the following Entity agreements:

- The Entity agreements, signed 28 July and 12 August 1988, on "Principles for the Preparation of the AOP and Determination of Downstream Power Benefit (DDPB) Studies" and "Changes to Procedures for the Preparation of the AOP and DDPB Studies" (1988 Entity Agreements);

- The "Columbia River Treaty Entity Agreement on Resolving the Dispute on Critical Period Determination, the Capacity Entitlement for the 1998-99, 1999-00, and 2000-01 AOP/DDPBs, and Operating Procedures for the 2001-02 and Future AOPs," signed 29 August 1996 (1996 Entity Agreement); and

- Except for the changes noted below, the "Columbia River Treaty Entity Agreement on the Principles and Procedures for Preparing and Implementing Hydroelectric Operating Plans For Operation of Canadian Treaty Storage" (POP), dated October 2003 and signed 16 December 2003, including the September 2011 update to Appendix 1 - Refill Curves; the November 2004 addition of Appendix 6 - Streamline Procedures; the addition of Appendix 7 – Table of Median Flows based on the 2010 Level Modified Streamflows; and the September 2007 addition of Appendix 8 concerning Water Supply Forecasts along with the February 2012 revision of Appendix 8, Table 1, concerning the Summary of Errors and Hedges.

Special terms used in this document, but not defined herein, have the meanings defined in the Treaty, Protocol, or the above Entity agreements. The POP is based on criteria contained in Annex A and Annex B of the Treaty, the Protocol, and the "Columbia River Treaty Flood Control Operating Plan" (FCOP) dated May 2003.

For the DDPB19, the Entities have agreed to use all three streamline procedures defined in Appendix 6 of the POP. These streamline procedures include "Forecasting Loads and Resources" for determining the thermal installations, as described in Subsection 7(d) of the accompanying document, Columbia River Treaty Hydroelectric Operating Plan of the Assured Operating Plan for Operating Year 2018-19 (AOP19), the "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage" based on the AOP18 Joint Optimum Step I system regulation study, as explained in Subsection 2(b) of the AOP19, and the "Monthly Hydro Energy Reshaping for Step II and III 30-year System Regulation Studies" for determining the energy entitlement, as described in Subsection 7(f) of this document.

In addition to the changes discussed in Subsection 2(a) of the AOP19 document, the Entities have agreed to modify the DDPB19 Table 2 calculation of Thermal Displacement Market (TDM), as was done since DDPB13, to use thermal imports (e.g. market purchases of power from California, but not Canadian Entitlement (CE) or Skagit Treaty power) to support exports (not including CE, plant sales, flow-through-transfers (FTT), seasonal exchanges (SE) or excess extra-regional thermal installations), on an annual basis, as either FTTs or SEs.

The Canadian Entitlement Benefits were computed from the following studies:

Step I -- Operation of the total United States of America (USA) Columbia Basin hydro and thermal system, with 19.12 cubic kilometers[1] (km^3) (15.5 million acre-feet (Maf)) of Canadian Treaty Storage operated for flood control and optimum power generation in both countries including coordination with other generation in Canada and the USA;

Step II -- Operation of the Step I thermal system, the base hydro system, and 19.12 km^3 (15.5 Maf) of Canadian Treaty Storage operated for flood control and optimum power generation in both countries; and

Step III -- Operation of the Step I thermal system and the base hydro system operated for flood control and optimum power generation in the United States.

As part of the DDPB, separate determinations may be carried out relating to the limit of year-to-year reduction in benefits attributable to the operation of Canadian Treaty Storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the USA (Joint Optimum). However, as indicated in Section 4 below, the calculations were not needed for the 2018-19 operating year.

3. Results of Canadian Entitlement Computations

The Canadian Entitlement to the downstream power benefits in the USA attributable to operation in accordance with Treaty Annex A, paragraph 7, for optimum power generation in Canada and the USA, which is one-half the total downstream power benefits, was determined to be (see Joint Optimum results in Table 5):

Dependable Capacity	= 1284.0 megawatts (MW)
Average Annual Usable Energy	= 472.5 average annual MW

All downstream power benefit computations are rounded to the nearest tenth of a MW.

4. Computation of Maximum Allowable Reduction in Downstream Power Benefits

Treaty Annex A, paragraph 7, states in part that:

> *". . . Any reduction in the downstream power benefits in the United States of America resulting from that change in operation of the Canadian storage shall not exceed in any one year the reduction in downstream power benefits in the United States of America which would result from reducing by 500,000 acre-feet the Canadian storage operated to achieve optimum power generation in the United States of America and shall not exceed at any time during the period of the Treaty the reduction in downstream power benefits in the United States of America which would result from similarly reducing the Canadian storage by 3,000,000 acre-feet."*

Step II studies based on the assumption of optimum power generation in Canada and the USA resulted in a 1.3 average annual megawatt (aMW) increase in the Energy Entitlement and no change in the Capacity Entitlement compared to the Step II study based on optimum power generation only in the USA (see Table 5, columns A and B). Since there was no reduction in the downstream power benefits for the Joint Optimum Study, the computation of the maximum allowable reduction in downstream power benefits, as defined in Section 3.3.A(3) of the POP, was not necessary.

5. Delivery of the Canadian Entitlement

See Section 6 of the AOP19.

6. Summary of Information Used for Canadian Entitlement Computations

The following tables and chart summarize the study results:

Table 1A Determination of Step I Firm Energy Hydro Loads
and
Table 1B Determination of Step I Firm Peak Hydro Loads

These tables follow the definition of Step I loads and resources defined by Treaty Annex B, paragraph 7, and clarified by the 1988 Entity Agreements and modified according to the Streamline Procedures noted in Section 2 of this DDPB and described in Section 7 of the AOP19. Table 1A shows the Step I energy loads and resources while Table 1B shows the Step I peak loads and resources.

Table 2 Determination of Thermal Displacement Market

This table shows the computation of the TDM for the downstream power benefit determination of average annual usable energy. The TDM is calculated as the thermal installations shown in Table 1A with subsequent reductions for estimated minimum thermal generation and system sales. System sales are all exports except for Canadian Entitlement, plant sales, seasonal exchanges, and flow-through-transfers, as defined in POP and modified in Section 2 of this DDPB.

Table 3 Determination of Loads for Step II and Step III Studies

This table shows the computation of the Step II and III loads. The monthly loads for Steps II and III studies have the same ratios between each month and the annual average as the PNWA load (to maintain the same annual load shape). The PNWA firm loads were based on the Bonneville Power Administration (BPA) 2012 White Book (WB12) load forecast as described in Subsection 7(a) of the AOP19. The Grand Coulee net pumping load is included in this estimate. The method for computing the firm load for the Steps II and III studies is described in the 1988 Entity Agreements and in the POP.

Table 4 Summary of Steps I, II, and III Power Regulations

This table summarizes the results of the Steps I, II, and III power regulation studies for each project and the total system. The determination of the Steps I, II, and III loads and thermal installations is shown in Tables 1 to 3.

Hydro maintenance, transmission losses and peaking reserves (for capacity balance) are summed together in the Step I load-resource balance as a resource adjustment. The Steps II and III capacity balance includes the hydro maintenance and the peaking reserves based on the same percentage as the Step I system.

The firm energy load carrying capability for the Steps I, II, and III systems is based on the same critical periods as recent studies. The firm peak load carrying capability for each system is based on the period with the lowest surplus firm peak capability over the thirty water years. For the AOP/DDPB19, these periods are January 1932 for the Steps I and II systems and January 1930 for the Step III system.

Table 5 Computation of Canadian Entitlement

A. Joint Optimum Generation in Canada and the USA
B. Optimum Generation in the USA Only

The essential elements used in the computation of the Canadian Entitlement arising from the downstream power benefits under the Joint Optimum and USA Optimum are shown under Columns A and B, respectively. These elements are derived from (1) Steps II and III USA Optimum critical period studies based on loads determined in Table 3; (2) the Thermal Displacement Market from Table 2; and (3) the Step II Joint Optimum and Step III USA Optimum 30-year hydro regulation studies based on the DDPB18 with revisions to reshape generation to the 2018-19 Steps II and III loads as described in Subsection 7(f).

As explained in Section 4 of this document, the computation of maximum allowable reduction in downstream power benefits are not shown in this table because the calculation was not necessary.

Table 6 Comparison of Recent DDPB Studies

Chart 1 Duration Curves of 30 Years Monthly Hydro Generation

This chart shows duration curves of the hydro generation in aMW from the Joint Optimum Step II and the USA Optimum Step III system regulation studies[2] which graphically illustrate the change in average annual usable hydro energy.

Usable hydro energy consists of firm energy plus usable nonfirm energy. Firm energy, as shown in Table 5, is equal to the firm hydro loads. Nonfirm energy is the monthly hydro energy capability in excess of the firm hydro loads. The usable nonfirm energy is computed in accordance with Annex B, paragraphs 3(b) and 3(c), as the portion of nonfirm energy that can be used to displace thermal installations designated to meet PNWA firm loads, plus the remaining usable energy. The Entities agree that remaining usable energy is computed on the basis of 40% of the nonfirm energy remaining after thermal displacement.

7. Summary of Changes Compared to the 2017-18 DDPB and Notable Assumptions

Data from recent DDPBs are summarized in Table 6. The following is an explanation of changes and notable assumptions that impact computation of the Entitlement compared to the DDPB18 studies.

a) Steps II and III Firm Loads

The Steps II and III hydro firm load shape shown on Table 3 is somewhat different from the DDPB18. For DDPB19, the 2018-19 loads trend higher in April and August and lower in October, December through February, and again in May and June. This is mainly due to the change in PNWA load shape and thermal maintenance schedules, as explained in Subsection 7(b).

Differences between DDPB19 and DDPB18 Table 3 Hydro Loads

	Aug1	Aug2	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr2	May	June	July	Avg.	CPavg
DDPB19 S2	8741	8734	7407	6670	8595	10244	10529	9631	8737	8306	8848	10025	9097	9468	8977	8906
DDPB18 S2	8659	8641	7393	6738	8586	10414	10605	9686	8745	7494	8268	10534	9300	9431	8999	8903
Difference	82	93	15	-67	8	-170	-76	-56	-8	812	579	-510	-203	38	-22	3
DDPB19 S3	6353	6346	5199	4546	6219	7636	7891	7123	6434	6104	6641	7883	6782	7001	6621	6978
DDPB18 S3	6288	6272	5188	4608	6214	7793	7965	7176	6435	5304	6058	8392	6986	6979	6644	6957
Difference	65	74	11	-62	5	-157	-74	-52	-1	800	583	-508	-205	21	-23	21

The average critical period load factor increased from 74.60% in AOP18 (WB11) to 75.08% in AOP19 (WB12).

b) Thermal Installations

The total thermal installation energy capability shown in Tables 1 to 3 decreased by 22 annual aMW compared to the DDPB18. This is due to the combined effects of increases in PNWA firm load (270 aMW), exports (69 aMW), imports (196 aMW), and renewable resources (165 aMW), most of which is wind.

Beginning with AOP06, Columbia Generating Station changed from an annual maintenance cycle to a 24 month cycle. This created a circumstance where this maintenance was included only in alternate years of the AOP with a resulting effect of swings in Energy Entitlement. Beginning with AOP/DDPB14 and continuing with this AOP/DDPB, the Entities have agreed to use the average of the two year maintenance schedule, thereby eliminating the year to year Energy Entitlement variability and effect on the AOP storage operations.

In addition, the thermal installation shape has changed due to changes in thermal maintenance schedules (mostly coal but also combustion turbines and co-generation).

The TDM increased by 67 annual aMW, due to changes in system sales. Both the thermal installation and TDM changes are shown in the following table.

DDPB19 minus DDPB18 Table 2 Thermal Installations and Thermal Displacement Market

	Aug1	Aug2	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr2	May	June	July	Avg.	CP avg
DDPB19 T.I.	10381	10380	10271	10335	10428	10637	10590	10442	9700	9326	8815	7116	9437	10287	9888	9973
DDPB18 T.I.	10381	10379	10305	10357	10461	10633	10593	10471	9797	10087	9476	6667	9276	10251	9909	9994
Difference	1	1	-34	-22	-33	4	-3	-29	-97	-762	-661	449	161	36	-22	-21
TDM 19	10041	10040	9933	9996	10087	10291	10245	10100	9376	9012	8513	6848	9108	9948	9558	9641
TDM 18	9952	9951	9878	9929	10030	10198	10159	10040	9383	9666	9070	6323	8862	9824	9491	9574
Difference	89	89	55	67	56	93	86	60	-7	-654	-556	525	246	124	67	68

c) Hydro Project Modified Stream Flows

The unregulated base stream flows used in the Steps II and III system regulation studies are the same as those used in the Step I studies (see Subsection 7(e) of AOP19), which were the 2010 Modified Streamflows published by BPA in August

2011, except for adjustments to add the effect of natural lake regulation and remove reservoir evaporation at projects not included in Steps II or III.

d) Hydro Project Rule Curves

As explained in Subsection 7(f) of the AOP19 document, critical rule curves and refill curves are the same as the AOP18.

e) Other Hydro Project Operating Procedures, Constraints, and Plant Data

As explained in Subsection 7(g) of the AOP19 document, operating procedures, constraints, and plant data are the same as used in the AOP18, and are described in Subsection 7(g) of the AOP18 document.

f) Steps II and III Critical Period and 30-year System Regulation Studies

Critical period studies are performed to establish the length of the critical stream flow period and the hydro firm load carrying capability. The Entities conducted Step II and Step III critical period system regulation studies for the 2018-19 operating year in accordance with procedures described in Section 3.3 of the POP.

The Step II and Step III critical stream flow periods are unchanged from the DDPB18 studies. The Step II critical period comprises the 20 calendar-months from 1 September 1943 through 30 April 1945, and the Step III critical period consists of the 5.5 calendar-months from 1 November 1936 through 15 April 1937. The Step II critical period generation, as compared to DDPB18, increased by 3.3 aMW, while the average annual firm energy decreased by 21.8 aMW. The Step III critical period generation increased by 20.9 aMW, but the average annual firm energy decreased by 23.2 aMW. These changes to critical period generation and average annual firm energy are primarily due to changes in the Steps II and III load shapes.

For the 30-year System Regulation Studies, the Entities agreed to use the Streamline procedure “Monthly Hydro Energy Reshaping for Step II and III 30-year System Regulation Studies”, based on the DDPB18, along with a month-to-month generation reshaping procedure, to estimate Steps II and III 30-year average annual usable hydro energy for this DDPB. The procedure reshapes the monthly hydro generation from the DDPB18 30-year hydro system regulation study by borrowing surplus energy from future months to meet any deficits under the DDPB19 Steps II and III firm hydro loads.

g) Downstream Power Benefits

The Canadian Capacity Entitlement decreased from 1304.1 MW in the DDPB18 to 1284.0 MW in the DDPB19, a decrease of 20.1 MW. This is caused by a slight increase in the critical period load factor as well as a smaller increase in the Step II critical period generation relative to the Step III critical period generation.

The Canadian Energy Entitlement decreased from 475.0 annual aMW in the

DDPB18 to 472.5 annual aMW in the DDPB19, a decrease of 2.5 annual aMW. This decrease is caused mainly by a combination of changes in the shape of the Thermal Displacement Market as well as the Steps II and III loads.

End Notes:

[1] The Treaty defines the Canadian Treaty Storage in English units. The metric conversion is a rounded approximation.

[2] The Steps II and III DDPB19 hydro system generation estimates, dated 25 September 2013, were determined by applying the third streamline procedure to reshape the DDPB18 system regulation studies.

TABLE 1A
DETERMINATION OF STEP I FIRM ENERGY HYDRO LOADS
FOR 2018-19 ASSURED OPERATING PLAN
(Average MW)

	Aug15	Aug31	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	Jun	Jul	Ann. Avg.	CP Avg. 1/
1. Pacific Northwest Area (PNWA) Firm Load																
a) White Book Regional Firm Load 2/	23893	23915	22077	21227	23686	26000	26245	24987	22965	21993	21993	21434	23268	24828	*23548*	*23622*
b) Exclude 99% of UPL's Idaho load 3/	-525	-525	-474	-441	-433	-467	-439	-453	-427	-407	-407	-455	-580	-640	-479	-475
c) Update Coulee pumping 4/	-7	-39	-7	-12	-14	-24	-6	-13	-15	-46	-9	-40	-46	-54	-24	-22
d) …Total PNWA Firm Loads	**23360**	**23350**	**21596**	**20774**	**23239**	**25509**	**25800**	**24521**	**22522**	**21540**	**21577**	**20939**	**22642**	**24134**	**23046**	**23124**
e) Annual Load Shape in Percent	101.4	101.3	93.7	90.1	100.8	110.7	112.0	106.4	97.7	93.5	93.6	90.9	98.2	104.7	100.0	100.3
2. Flows-Out of firm power from PNWA																
a) White Book Exports, incl firm sp 5/	1691	1762	1478	1493	1238	1121	1090	1157	1445	1496	1477	1312	1650	1616	1403	1387
b) Remove WB Canadian Entitlement	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464
c) Add est. Can. Entitle. Exported 6/	470	470	470	470	470	470	470	470	470	470	470	470	470	470	470	470
d) Added export for WB surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Added SeEx for WB Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Added SeEx for AOP Hydro 7/	0	0	279	0	0	204	0	0	0	0	0	601	389	145	136	126
g) Imp. Thermal used out of region 8/	95	95	113	121	88	50	52	48	51	76	54	0	80	70	69	71
h) …Subtotal for Table 2	1792	1863	1877	1620	1332	1381	1148	1211	1503	1578	1538	1919	2125	1838	1614	1591
i) Remove Plant Sales	-878	-909	-810	-767	-748	-636	-605	-549	-859	-1025	-1007	-841	-1133	-952	-818	-801
j) Remove Flow-through-transfer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
k) …Total	**914**	**953**	**1067**	**853**	**584**	**745**	**543**	**663**	**644**	**553**	**531**	**1078**	**992**	**886**	**795**	**790**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations																
a) White Book Imports 9/	-981	-973	-776	-738	-946	-1326	-985	-965	-815	-719	-719	-761	-923	-994	-911	-918
b) Remove UP&L imports for 1(b) 3/	526	525	474	441	433	467	439	453	427	407	407	455	580	640	479	475
c) Remove Eastern Thermal Instal 10/	304	304	281	276	313	360	355	353	318	278	278	275	300	326	311	313
d) Added SeEx for WB Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Added Can.Import for WB deficits 11/	0	-18	-207	0	-5	-264	-470	-421	-331	-179	-36	0	0	-252	-171	-177
f) Added Calif.Import for WB deficits 12/	0	0	0	0	0	0	-22	0	0	0	0	0	0	0	-2	-2
g) Added SeEx for AOP Hydro 7/	-128	-253	0	-177	-148	0	-129	-187	-201	-655	-555	0	0	0	-136	-133
h) Remove Flow-Through-Xfers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
i) …Total	**-279**	**-415**	**-228**	**-199**	**-353**	**-763**	**-812**	**-767**	**-601**	**-869**	**-625**	**-32**	**-42**	**-280**	**-429**	**-442**
4. PNWA Non-Step I Hydro and Non-Thermal Resources																
a) Hydro Independents (1929 water)	-1004	-986	-983	-1084	-1104	-995	-1013	-842	-952	-1121	-1151	-1426	-1375	-1111	-1086	-963
b) Non-Step I Coordinated Hydro(1929)	-495	-458	-551	-925	-934	-945	-1245	-673	-715	-810	-705	-641	-1054	-658	-798	-808
c) WB Regional Hydro NUGs	-322	-321	-241	-163	-130	-123	-115	-123	-154	-273	-278	-398	-419	-418	-241	-229
d) WB Renewable NUGs	-62	-62	-62	-62	-62	-62	-62	-62	-61	-62	-61	-61	-61	-61	-62	-62
e) WB Renewables	-872	-1415	-1299	-1151	-973	-880	-621	-642	-1077	-1472	-1108	-1252	-1640	-1300	-1108	-1087
f) …Total (1929)	**-2754**	**-3242**	**-3136**	**-3384**	**-3202**	**-3005**	**-3055**	**-2342**	**-2960**	**-3737**	**-3303**	**-3778**	**-4550**	**-3549**	**-3295**	**-3149**
5. Step I System Load (1929) 13/	**21241**	**20647**	**19299**	**18045**	**20267**	**22486**	**22475**	**22075**	**19606**	**17486**	**18179**	**18206**	**19041**	**21191**	**20116**	**20323**
6. Coordinated Thermal Installations 14/																
a) Columbia Generation Station (WNP2)	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	681	515	980	954	965
b) Generic Thermal Installations	9351	9350	9241	9305	9398	9607	9560	9412	8670	8296	7785	6435	8922	9307	8934	9008
c) ...Total	**10381**	**10380**	**10271**	**10335**	**10428**	**10637**	**10590**	**10442**	**9700**	**9326**	**8815**	**7116**	**9437**	**10287**	**9888**	**9973**
7. Step I Hydro Resources (1929) 15/	**11533**	**10941**	**9656**	**8309**	**10500**	**12578**	**12617**	**12333**	**10550**	**8774**	**9979**	**11703**	**10260**	**11598**	**10891**	**11014**
8. Step I Resource Adjustments																
a) Hydro Maintenance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) Transmission System Losses 16/	-674	-674	-628	-599	-661	-730	-732	-700	-644	-613	-614	-613	-656	-695	-662	-664
9. Total Step I System Resources(1929)	**21241**	**20647**	**19299**	**18045**	**20267**	**22486**	**22475**	**22075**	**19606**	**17486**	**18179**	**18206**	**19041**	**21191**	**20116**	**20323**
10. Coordinated Hydro Load (1929) 17/	**12028**	**11399**	**10207**	**9233**	**11434**	**13523**	**13862**	**13006**	**11264**	**9583**	**10684**	**12344**	**11314**	**12256**	**11689**	**11822**
a) Coord. Hydro Load Shape (1929) 18/	102.9%	97.5%	87.3%	79.0%	97.8%	115.7%	118.6%	111.3%	96.4%	82.0%	91.4%	105.6%	96.8%	104.9%	*100.0%*	

Notes:

1/ The Step I critical period is the 42.5 months beginning 16 August 1928 and ending 29 February 1932.
2/ BPA Final 2012 White Book (WB12) total regional firm load estimate, which includes estimated Coulee pumping and Idaho loads served by Utah P&L.
3/ Annex B requires exclusion of Idaho load from area served by Utah Power Light in 1964. We exclude import that supports that, but include the import for the 1% within the region.
4/ Coulee pumping loads were updated to the 2012 PNCA data submittal to be consistent with the pumping flows in the Base Flows.
5/ WB12 exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and an estimate of the Canadian Entitlement.
6/ Assumes 470 MW Energy Entitlement exported to Canada.
7/ Seasonal Exchanges were employed in this AOP to make the Coordinated Hydro Load in Line 10 match the AOP18 Coordinated Hydro Load.
8/ Added thermal export to balance difference between thermal import and equivalent thermal installation based on generic annual shape.
9/ White Book Imports include coordinated thermal installations, seasonal & capacity exchanges, flow-through-transfers, and Skagit Treaty power.
10/ Imports identified as coordinated thermal installations are excluded, to be replaced by a portion of the Generic Thermal Installations.
11/ Added Canadian import as a portion of the resources needed to balance WB deficits, based on 36% of estimated 470 aMW of Energy Entitlement .
12/ Added Calif. import as a portion of the resources needed to balance WB deficits, based on the proata procedure.
13/ Lines 1d + 2k + 3i + 4f, based on 1929 hydro independent capability.
14/ Thermal installations are CGS, plus a generic thermal installation that is sized to meet the Step 1 System load minus Step I Hydro.
15/ Step I Hydro (US hydro projects at and upstream of Bonneville Dam) critical period capability shaped to 1929 load, line 5 minus lines 6c, 8a, & 8b.
16/ Transmission losses are 2.71% of all resources including imports.
17/ The Coordinated Hydro Load is the Step I Hydro Resources plus Non-Step I Coordinated Hydro, lines 7 - 4b.
18/ The Coordinated Hydro Load Shape shows the net effect of loads and nonhydro resources on the coordinated system hydro resources.

TABLE 1B
DETERMINATION OF STEP I FIRM PEAK HYDRO LOADS FOR 2018-19 ASSURED OPERATING PLAN
(MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. Pacific Northwest Area (PNWA) Firm Load														
a) White Book Regional Firm Load	32254	32254	28768	29359	32515	35861	35783	33881	31057	29462	29462	27840	31017	33286
b) Exclude 99% of UPL's Idaho load	-740	-740	-622	-563	-560	-641	-584	-583	-559	-531	-531	-572	-809	-884
c) Adj.for Federal Peak Diversity 1/	-499	-536	-565	-364	-311	-570	-315	-336	-391	-501	-516	-524	-527	-429
d) Updates to Coulee pumping forec.	-65	-65	-28	-76	126	126	251	-21	0	-18	-28	-2	-7	-72
e) ...Total PNWA Firm Loads	**30951**	**30913**	**27553**	**28356**	**31769**	**34777**	**35135**	**32941**	**30106**	**28413**	**28388**	**26741**	**29675**	**31901**
f) Monthly Load Factors in Percent	75.48	75.54	78.38	73.26	73.15	73.35	73.43	74.44	74.81	75.81	76.01	78.30	76.30	75.65
2. Flows-Out of firm power from PNWA														
a) White Book Exports	2011	2052	1898	1799	1530	1530	1530	1659	1646	1530	1538	1394	1838	1870
b) Remove WB Canadian Entitlement	-1324	-1324	-1324	-1324	-1324	-1324	-1324	-1324	-1324	-1324	-1324	-1324	-1324	-1324
c) Add estimated Can.Entitle. exported	1295	1295	1295	1295	1295	1295	1295	1295	1295	1295	1295	1295	1295	1295
d) Added export for WB surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Add Seasonal Exch. WB Export	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Add Seasonal Exch. Shape Export	0	0	279	0	0	204	0	0	0	0	0	601	389	145
g) Thermal Inst. used outside region 2/	71	71	95	103	64	0	12	12	37	69	69	16	49	53
h) ...Subtotal for Table 2	*2053*	*2094*	*2243*	*1873*	*1565*	*1704*	*1512*	*1641*	*1654*	*1569*	*1577*	*1982*	*2247*	*2039*
i) Remove Plant Sales	-199	-199	-199	-199	-199	-199	-199	-199	-199	-199	-199	-55	-199	-199
j) Remove Flow-through-transfer	0	0	0	0	0	0	0	0	0	0	0	0	0	0
k) ...Total	**1854**	**1896**	**2044**	**1674**	**1366**	**1505**	**1313**	**1443**	**1455**	**1370**	**1378**	**1927**	**2048**	**1840**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations														
a) White Book Imports	-1415	-1408	-1154	-1095	-1415	-1831	-1568	-1598	-1251	-1064	-1064	-1096	-1369	-1459
b) Remove UP&L imports for SW Idaho	740	740	622	563	560	641	584	583	559	531	531	572	809	884
c) Remove Eastern Thermal Instal	401	401	380	379	422	483	477	475	426	369	369	371	406	420
d) Added SeEx for WB Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Added Can.Import for WB deficits	0	-1295	-1295	0	-1295	-1295	-1295	-1295	-1295	-1295	-1295	0	0	-1295
f) Added Calif.Import for WB deficits	0	0	0	0	0	0	-22	0	0	0	0	0	0	0
g) Added Seas.Exch. for Aop hydro	-128	-253	0	-177	-148	0	-129	-187	-201	-655	-555	0	0	0
h) Remove Flow-Through-Xfers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
i) ...Total	**-401**	**-1815**	**-1448**	**-330**	**-1875**	**-2003**	**-1954**	**-2022**	**-1761**	**-2115**	**-2014**	**-152**	**-154**	**-1450**
4. PNWA Non-Step I Hydro and Non-thermal Resources														
a) Hydro Independents (1932)	-1282	-1272	-1232	-1124	-1257	-1386	-1561	-1264	-1633	-1633	-1647	-1895	-1779	-1529
b) Non-Step I Coord. Hydro (1932)	-1503	-1577	-1930	-2015	-2161	-2134	-2050	-1911	-1822	-1788	-2020	-2026	-2376	-2439
c) WB Regional Hydro NUGs	-401	-399	-327	-244	-185	-174	-166	-177	-216	-326	-340	-464	-481	-471
d) WB Renewable NUGs	-77	-77	-77	-77	-77	-77	-77	-77	-76	-76	-76	-76	-76	-76
e) WB Renewables	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38
f) ... Total (1932)	**-3300**	**-3362**	**-3603**	**-3498**	**-3718**	**-3809**	**-3892**	**-3468**	**-3784**	**-3862**	**-4121**	**-4499**	**-4749**	**-4554**
5. Step I System Load 3/ (1932)	**29104**	**27632**	**24546**	**26202**	**27542**	**30471**	**30603**	**28894**	**26016**	**23807**	**23630**	**24017**	**26820**	**27738**
6. Coordinated Thermal Installations														
a) Columbia Generating Station (cgs)	1130	1130	1130	1130	1130	1130	1130	1130	1130	1130	1130	565	565	1130
b) Generic Thermal Installations	11089	11089	11135	11312	11398	11459	11467	11426	10871	10256	10256	9094	10681	11091
c) ...Total	**12219**	**12219**	**12265**	**12442**	**12528**	**12589**	**12597**	**12556**	**12001**	**11386**	**11386**	**9659**	**11246**	**12221**
7. Step I Hydro Resc. Needed (1932) 4/	**26752**	**25288**	**22798**	**24717**	**25168**	**27322**	**26876**	**24874**	**22651**	**21099**	**20483**	**21937**	**23659**	**24603**
8. Step I Resource Adjustments														
a) Hydro Maintenance 5/	-4445	-4397	-5075	-5614	-4590	-3707	-3136	-3042	-3385	-3374	-2787	-2185	-2265	-3240
b) ...Hydro maint. as % reg. hydro capa	*14.5%*	*14.3%*	*16.2%*	*18.0%*	*14.6%*	*11.7%*	*10.1%*	*10.4%*	*11.9%*	*11.5%*	*9.4%*	*7.1%*	*7.0%*	*10.1%*
c) Transmission System Losses 6/	-1135	-1183	-1165	-1116	-1202	-1242	-1241	-1193	-1135	-1154	-1182	-1124	-1211	-1250
d) Reserves (11% of resources) 7/	-4288	-4296	-4276	-4228	-4362	-4491	-4493	-4301	-4117	-4150	-4269	-4270	-4608	-4596
e) ...Peak reserves as % resources	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*
f) ...Total Adjustments	-9868	-9875	-10517	-10958	-10154	-9440	-8870	-8536	-8636	-8678	-8239	-7578	-8085	-9086
9. Required Step I Resources	**29104**	**27632**	**24546**	**26202**	**27542**	**30471**	**30603**	**28894**	**26016**	**23807**	**23630**	**24017**	**26820**	**27738**
10. Coordinated Hydro load and Surplus/Deficit (1932)														
a) Coordinated Hydro Load (1932) 8/	28255	26865	24728	26732	27329	29456	28926	26786	24473	22887	22502	23962	26034	27042
b) Actual Coord. Hydro Gen (1932) 9/	29410	29446	30014	30124	30158	30269	29547	28034	26844	27645	28109	28870	30540	30686
c) ...Surplus/Deficit (1932)	1155	2581	5286	3392	2829	813	621	1248	2371	4758	5607	4908	4506	3644

Notes:

1/ Federal peak diversity is a reduction in peak load due to peak loads not all being coincidental.

2/ Export or import to balance difference between excluded thermal imports and generic thermal installation.

3/ Total Step I Firm Peak Load is the sum of lines 1e + 2k + 3i + 4f.

4/ Step I hydro resources needed to meet the load = line 5 minus lines 6c and 8f. Actual resource capability is higher. Used 1932 because has lowest surplus.

5/ Maintenance factors from WB 1937 (but identified in WB as maintenance for 1929).

6/ Transmission losses are 3.35% of all resources including imports, net of reserves and maintenance.

7/ Assumed value.

8/ Lines 4b and 7.

9/ System Instantaneous Peak (1932).

TABLE 2
DETERMINATION OF THERMAL DISPLACEMENT MARKET
FOR 2018-19 AOP/DDPB STEPS II AND III STUDIES
(Average MW)

	Aug15	Aug31	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	Jun	Jul	Annual Average	CP Avg (42.5 mon)
1. STEP I THERMAL INSTALLATIONS																
a) From Table 1A, line 6(c)	10381	10380	10271	10335	10428	10637	10590	10442	9700	9326	8815	7116	9437	10287	9887.7	9973.2
2. DISPLACEABLE THERMAL RESOURCES																
a) Minimum Gen. from % of Thermal	233	233	230	232	234	239	238	234	216	207	194	160	222	232	222.5	224.3
b) Net Displaceable Thermal Resources	**10148**	**10148**	**10041**	**10104**	**10194**	**10398**	**10352**	**10207**	**9484**	**9119**	**8621**	**6956**	**9215**	**10056**	**9665.3**	**9748.9**
3. SYSTEM SALES (i.e. Amount of Coordinated Thermal Installation Power Used Outside PNWA)																
a) Flows-Out (Table 1A, line 2(h))	1792	1863	1877	1620	1332	1381	1148	1211	1503	1578	1538	1919	2125	1838	1613.6	1590.7
b) ...Exclude Can.Entitlement Exported	-470	-470	-470	-470	-470	-470	-470	-470	-470	-470	-470	-470	-470	-470	-470.0	-470.0
c) ...Exclude Plant Sales	-878	-909	-810	-767	-748	-636	-605	-549	-859	-1025	-1007	-841	-1133	-952	-818.4	-800.9
d) ...Exclude WB Flow-Through-Transfer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0
e) ...Exclude WB. Seasonal Exchange	-187	-187	-168	0	0	0	0	0	0	0	0	0	-46	-160	-47.1	-46.1
f) ...Exclude SeEx for WB Surp/Def	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0
g) ...Exclude SeEx for AOP Hydro Diff.	0	0	-279	0	0	-204	0	0	0	0	0	-601	-389	-145	-135.7	-126.3
h) ...Exclude Other Flow-ThruTransfer	-123	-116	-3	-3	-4	-71	-27	-4	-4	-3	-3	-3	-3	-3	-20.8	-21.7
i) ...Exclude Other Seasonal Exchange	-15	-21	-17	-44	-13	0	-5	-22	-20	-9	-7	0	-10	-12	-14.1	-14.5
j) ...Total System Sales	118	159	130	336	97	0	41	167	151	70	51	3	74	94	107.5	111.1
k) Uniform Average Ann.System Sales	108	108	108	108	108	108	108	108	108	108	108	108	108	108	107.5	107.5
4 THERMAL DISPLACEMENT MARKET																
a) Line 2b minus line 3k	**10041**	**10040**	**9933**	**9996**	**10087**	**10291**	**10245**	**10100**	**9376**	**9012**	**8513**	**6848**	**9108**	**9948**	**9557.7**	**9641.4**

Notes:

2a Minimum generation is 0.0249 times the monthly average Step I thermal, without CGS; based on 2006 AOP data.

3b Canadian Entitlement exports are assumed to be supported by hydro instead of thermal.

3c Plant sales include Longview Fibre and approximately 25 percent of Boardman; line 2i, Table 1A.

3d Flow-through-transfers from the White Book.

3e Seasonal Exchanges from the White Book.

3f f Seasonal exchange added to White Book value to export WB surplus.

3g Seasonal Exchanges were employed in this AOP to make the Coordinated Hydro Load in Line 10 match the AOP18 Coordinated Hydro Load.

3h Other flow through transfers are remaining flows-out supported by remaining thermal imports in the same period.

3i Other Seasonal Exchanges are remaining exports supported by thermal imports greater than imports on an annual basis.

3j Total System Sales are total exports excluding exchanges, plant sales, flow-thru-xfers, and the Canadian Entitlement. The sum of Lines 3a through 3i.

3k Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.

4 PNW Area Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNW Area firm loads. Lines 2b minus 3k.

TABLE 3
DETERMINATION OF LOADS FOR STEP II AND STEP III STUDIES
FOR 2018-19 AOP/DDPB STUDIES

	PACIFIC NORTHWEST AREA LOADS				THERMAL INSTALLATIONS			
Period	Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Energy Capability 2/ aMW	Annual Energy Shape Percent	Peak Capability MW	Capacity Factor Percent
August 1-15	23360	101.37	30951	75.48	10381	105.0%	12219	85.0%
August 16-31	23350	101.32	30913	75.54	10380	105.0%	12219	85.0%
September	21596	93.71	27553	78.38	10271	103.9%	12265	83.7%
October	20774	90.14	28356	73.26	10335	104.5%	12442	83.1%
November	23239	100.84	31769	73.15	10428	105.5%	12528	83.2%
December	25509	110.69	34777	73.35	10637	107.6%	12589	84.5%
January	25800	111.95	35135	73.43	10590	107.1%	12597	84.1%
February	24521	106.40	32941	74.44	10442	105.6%	12556	83.2%
March	22522	97.73	30106	74.81	9700	98.1%	12001	80.8%
April 1-15	21540	93.47	28413	75.81	9326	94.3%	11386	81.9%
April 16-30	21577	93.63	28388	76.01	8815	89.1%	11386	77.4%
May	20939	90.86	26741	78.30	7116	72.0%	9659	73.7%
June	22642	98.25	29675	76.30	9437	95.4%	11246	83.9%
July	24134	104.72	31901	75.65	10287	104.0%	12221	84.2%
Annual Avg. 7/	23045.6	100.00		75.21	9887.7	100.0%		82.4%
SI CP Avg(42.5mon)	23123.9			**75.08**	9973.2			
S2 CP Avg(20mon)	23104.0				10006.7			
S3 CP Avg(5.5mon)	24069.8	AvgAnnEn/MaxPeak= 65.6%			10264.1	AvgAnnEn/MaxPeak= 78.5%		

	STEP II SYSTEM				STEP III SYSTEM			
Period	Total Energy Load 3/ aMW	Total Peak Load MW	Hydro Energy Load 4/ aMW	Hydro Peak Load MW	Total Energy Load 3/ aMW	Total Peak Load MW	Hydro Energy Load 4/ aMW	Hydro Peak Load MW
August 1-15	19122.5	25336	8741.4	13117	16733.9	22171	6352.7	9952
August 16-31	19114.5	25305	8734.1	13086	16726.8	22144	6346.4	9925
September	17678.1	22555	7407.3	10289	15469.9	19737	5199.0	7472
October	17005.7	23212	6670.2	10769	14881.4	20312	4546.0	7870
November	19022.9	26006	8594.8	13478	16646.7	22757	6218.6	10230
December	20881.6	28469	10244.3	15880	18273.3	24912	7636.0	12324
January	21119.3	28761	10529.2	16164	18481.2	25168	7891.1	12571
February	20072.3	26965	9630.5	14409	17565.0	23597	7123.2	11041
March	18436.4	24645	8736.6	12644	16133.4	21566	6433.7	9565
April 1-15	17632.1	23259	8306.2	11872	15429.6	20353	6103.8	8967
April 16-30	17662.4	23238	8847.5	11851	15456.1	20335	6641.3	8949
May	17140.3	21890	10024.5	12231	14999.3	19156	7883.5	9497
June	18534.3	24292	9096.9	13046	16219.1	21257	6781.7	10012
July	19755.8	26114	9468.4	13893	17288.0	22852	7000.6	10631
Annual Avg. 7/	18864.9		8977.2		16508.4		6620.7	
S2 CP Avg(20mon)	18912.8		8906.1					
S3 CP Avg(5.5mon)					17242.1		6978.0	
Joint Optimum S2 CP capability 5/ =			**8906.11**		S3 CP capability 6/ =		**6978.00**	

Notes:

1/ The PNW Area load does not include the exports, but does include pumping.

2/ The thermal installations include all thermal used to meet the Step I system load. (Table 2, line 1(a)).

3/ The total firm load for the Step II and III studies is computed to have the same shape as the load of the PNW Area.

4/ The hydro load is equal to the total load minus the Step I study thermal installations for each period.

5/ Input is the assumed critical period average generation for the Step II hydro studies and is used to calculate the residual hydro loads.

6/ Input is the assumed critical period average generation for the Step III hydro studies and is used to calculate the residual hydro loads.

7/ The Annual Average is for the operating year. The Critical Period (CP) averages are for the historic w ater years.

TABLE 4
SUMMARY OF STEPS I, II, & III POWER REGULATIONS FOR 2018-19 ASSURED OPERATING PLAN

	BASIC DATA		STEP I				STEP II					STEP III				
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	hm ^{3}	CRITICAL CAPACITY FPLCC Jan 1932 MW	CRITICAL ENERGY FELCC Avg.Gen MW	USABLE STORAGE kaf	hm ^{3}	CRITICAL CAPACITY FPLCC Jan 1932 MW	CRITICAL PERIOD FELCC Avg.Gen MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	hm ^{3}	CRITICAL CAPACITY FPLCC Jan 1930 MW	CRITICAL PERIOD FELCC Avg.Gen MW	30 YEAR AVERAGE ANNUAL GEN. MW
1. HYDRO RESOURCES																
a) CANADIAN STORAGE																
Mica			7000	8634			7000	8634								
Arrow			7100	8758			7100	8758								
Duncan			1400	1727			1400	1727								
Subtotal			15500	19119			15500	19119								
b) BASE SYSTEM																
Hungry Horse	4	428	3072	3789	134	93	3008	3710	144	108	98	3008	3710	330	235	96
Kerr	3	160	1219	1504	168	122	1219	1504	175	112	129	1219	1504	175	155	125
Thompson Falls	6	85	0	0	85	56	0	0	85	53	58	0	0	85	66	58
Noxon Rapids	5	554	231	285	490	151	0	0	528	132	201	0	0	528	176	201
Cabinet Gorge	4	239	0	0	262	104	0	0	262	91	125	0	0	262	117	126
Albeni Falls	3	50	1155	1425	21	22	1155	1425	20	22	21	1155	1425	20	21	19
Box Canyon	4	74	0	0	71	46	0	0	71	44	48	0	0	71	57	47
Grand Coulee	24+3SS	6684	5185	6396	5911	2022	5072	6256	6020	1821	2396	5072	6256	5195	1225	2305
Chief Joseph	27	2535	0	0	2535	1075	0	0	2535	977	1314	0	0	2535	709	1239
Wells	10	840	0	0	840	421	0	0	840	390	491	0	0	840	288	444
Chelan	2	54	677	835	50	38	676	834	51	38	44	676	834	52	51	43
Rocky Reach	11	1267	0	0	1274	609	0	0	1274	563	732	0	0	1274	409	671
Rock Island	18	513	0	0	529	276	0	0	529	259	322	0	0	529	191	295
Wanapum	10	986	0	0	825	503	0	0	825	466	590	0	0	825	330	523
Priest Rapids	10	912	0	0	770	489	0	0	770	456	561	0	0	770	331	494
Brownlee	5	675	975	1203	675	198	974	1201	675	257	285	974	1201	662	243	286
Oxbow	4	220	0	0	220	83	0	0	220	107	116	0	0	220	105	116
Ice Harbor	6	693	0	0	693	206	0	0	693	221	297	0	0	693	162	297
McNary	14	1127	0	0	1127	615	0	0	1127	590	762	0	0	1127	438	708
John Day	16	2484	535	660	2484	943	0	0	2484	917	1264	0	0	2484	688	1220
The Dalles	22+2F	2074	0	0	1875	767	0	0	1875	744	1001	0	0	1875	563	957
Bonneville	18+2F	1088	0	0	1065	554	0	0	1065	537	677	0	0	1065	419	634
Kootenay Lake	0	0	673	830	0	0	673	830	0	0	0	673	830	0	0	0
Coeur d'Alene Lake	0	0	223	275	0	0	223	275	0	0	0	223	275	0	0	0
Total Base System 1/		23742	29445	36320	22104	9393	28500	35154	22268	8906	11535	13000	16035	21618	6977.9	10906
c) ADDITIONAL STEP I PROJECTS																
Libby	5	600	4980	6143	352	202										
Boundary	6	1055	0	0	855	368										
Spokane Rivr Plnts 2/	24	173	104	128	161	98										
Hells Canyon	3	450	0	0	370	165										
Dworshak	3	450	2015	2485	444	154				NOT APPLICABLE TO STEPS II & III						
Lower Granite	6	932	0	0	932	160										
Little Goose	6	932	0	0	932	169										
Lower Monumental	6	932	0	0	928	165										
Pelton, Rereg,& RB	7	423	274	338	419	139										
Total added Step I		5947	7373	9094	5393	1620										
d) Total Hydro		29689	52318	64533	27497	11013	44000	54273	22268	8906	11535	13000	16035	21618	6978	10906
2. THERMAL INSTALLATIONS 3/			CpEn/AnnPk=79%		12597	9973	CpEn/AnnPk=79%		12597	10007	9888	CpEn/AnnPk=81%		12597	10264	9888
3. RESOURCE ADJUSTMENTS																
a) Hydro maintenance 4/					-3136	0	-10.1% of hydro		-2245	n.a.	n.a.	-10.1% of hydro		-2179	n.a.	n.a.
b) Peaking reserves 5/					-4493	n.a.	-11% of resc.		-3835	n.a.	n.a.	-11% of resc.		-3764	n.a.	n.a.
c) Transmission losses 6/					-1241	-664			n.a.	n.a.	n.a.			n.a.	n.a.	n.a.
4. TOTAL RESOURCES 7/			CpEn/AnnPk=65%		31223	20322	CpEn/AnnPk=66%		28785	18913	21422	CpEn/AnnPk=61%		28272	17242	20794
5. Steps I, II, & III System Loads																
a) PNW Area firm load			CpEn/AnnPk=66%		35135	23124										
b) Net of Exports + Imports					-640	348										
c) Non-Step I resources					-2050	-808										
d) Hydro Independents					-1561	-963										
e) Miscellaneous resources					-281	-1377										
f) ...Net Step I,II,III System Load 8/			CpEn/AnnPk=66%		30603	20323	CpEn/AnnPk=66%		28761	18913	18865	CpEn/AnnPk=69%		25168	17242	16508
									FPLCC=28761					FPLCC=25168		
6. SURPLUS (Line 4 - 5 (f))					620	0			24	0	2558			3104	0	4286

CRITICAL PERIOD		STEP I	STEP II	STEP III
	Starts	August 16, 1928	September 1, 1943	November 1, 1936
	Ends	February 29, 1932	April 30, 1945	April 15, 1937
	Length (Months)	42.5 Months	20 Months	5.5 Months
	Study Identification	19-41	19-12 9/	19-13 9/

Notes

1/ The above totals may not exactly equal the sum of the above values due to rounding. The total Base System Storage for Steps I & II includes Canadian storage.

2/ Spokane River Plants include: Little Falls, Long Lake, Nine Mile, Monroe, Upper Falls, and Post Falls.

3/ From Tables 1a, 1b and 3.

4/ Step I hydro maintenance from Tables 1a and 1b. Steps II/III peak hydro maintenance is the same percent as Step I coordinated Hydro; no energy maintenance loss was included because impact is negligible. Hydro maintenance energy losses are not included in Steps II & III.

5/ Steps I, II, and III peak reserves are 11% of resources.

6/ Step I transmission losses from Table 1a and 1b. Steps II & III transmission losses are not included, since it would change the energy load by the same amount.

7/ Total Resources is the sum total of lines 1b + 2 + 3a + 3b + 3c . For Step I, this does not include non-Step I coordinated hydro or hydro-independents.

8/ Step I energy load from Table 1a, line 5, and January peak load from Table 1b, line 5. Steps II & III energy load from Table 3. Steps II & III peak loads are equal to Steps II and III January energy load divided by the PNWA January load factor.

9/ Steps II and III FPLCC and 30 Year Average Annual Gen are from 1842 and 1813 studies, respectively. FELCC's are from 1912 and 1913 Critical Period studies.

TABLE 5
COMPUTATION OF CANADIAN ENTITLEMENT
FOR 2018-19 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S.
(from agreement in place of the 19-42 and 19-13 30-yr studies)
B. Optimum Power Generation in the U.S. Only
(from agreement in place of the 19-12 and 19-13 30-yr studies)

Determination of Dependable Capacity Credited to Canadian Storage (MW)	**(A)**	**(B)**
Step II - Critical Period Average Generation 1/	8906.1	8906.1
Step III - Critical Period Average Generation 2/	6978.0	6978.0
Gain Due to Canadian Storage	1928.1	1928.1
Average Critical Period Load Factor in percent 3/	75.08	75.08
Dependable Capacity Gain 4/	2567.9	2567.9
Dependable Capacity Limit (from Table 4) 5/	3592.6	3592.6
Canadian Share of Dependable Capacity 6/	**1284.0**	**1284.0**
Determination of Increase in Average Annual Usable Hydro Energy (aMW)		
Step II (with Canadian Storage) 1/	**(A)**	**(B)**
Firm Energy 7/	8977.6	8977.6
Thermal Displacement Energy 8/	2432.6	2429.1
Remaining Usable Energy 9/	49.9	50.7
System Average Annual Usable Energy	11460.1	11457.4
Step III (without Canadian Storage) 2/		
Firm Energy 7/	6621.0	6621.0
Thermal Displacement Energy 8/	3633.4	3633.4
Remaining Usable Energy 9/	260.7	260.7
System Average Annual Usable Energy	10515.1	10515.1
Average Annual Usable Energy Gain 10/	945.0	942.3
Canadian Share of Average Annual Energy Gain 5/	**472.5**	**471.2**

1/ Step II values were obtained from the 19-12 Critical Period study for Capacity Entitlement, and the Streamline Method using 18-12 and 18-42 30-year studies for Energy Entitlement.
2/ Step III values were obtained from the 19-13 Critical Period study for Capacity Entitlement, and the Streamline Method using 18-13 30-year study for Energy Entitlement.
3/ Critical period load factor from Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ From Table 4. Does not set a precedent or necessarily imply agreement on calculation of this value.
6/ One-half Dependable Capacity or Usable Energy Gain, as limited by Capacity Credit Limit.
7/ From 30-year average firm load served, which includes 7 leap years (29 days in February), so slightly different than Table 3.
8/ Average secondary generation limited to Potential Thermal Displacement Market.
9/ Forty percent (40%) of the remaining secondary energy.
10/ Difference between Step II and Step III Average Annual Usable Energy.

TABLE 6
COMPARISON OF RECENT DDPB STUDIES
(English and Metric units)

	2014-15		2015-16		2016-17		2017-18		2018-19	
AVERAGE PNWA ENERGY LOAD										
Annual Load (MW)	23013.7		22478.2		22801.8		22775.6		23045.6	
January Load Factor (%) 1/	112.8		112.5		112.6		112.1		112.0	
Critical Period (CP) Avg. Load Factor (%)	74.8		73.9		74.0		74.6		75.1	
Annual Firm Exports 2/	833.0		832.3		841.9		725.6		795.2	
Annual Firm Imports 3/	467.0		378.6		400.4		233.1		429.3	
Annual Non-Step 1 Hydro & Misc Rsrc 4/	2919.0		3022.4		3012.8		3130.5		3295.1	
Total Annual Step 1 Load 5/	20462.0		19909.5		20230.6		20137.6		20116.4	
THERMAL INSTALLATIONS (MW) 6/										
January Peak Capability	13734.6		12146.7		12533.5		12367.5		12596.8	
CP Energy	10215.7		9662.4		9995.3		9994.3		9973.2	
CP Minimum Generation	230.3		216.6		224.8		224.8		224.3	
Average Annual System Export Sales	180.5		252.6		239.3		195.9		107.5	
Average Annual Displaceable Market	9708.5		9111.5		9448.2		9490.6		9557.7	
Average Annual Energy 7/	10117.0		9578.8		9910.5		9909.4		9887.7	
HYDRO RESOURCES (aMW)										
Average Annual Step 1 Hydro Resources 8/	11021.0		10994.7		10991.3		10890.9		10890.9	
Average Annual Step 1 Coord Hydro Load 9/	11819.0		11793.9		11790.9		11689.3		11689.3	
STEP I/II/III CP (MONTHS)	42.5/20/5.5		42.5/20/5.5		42.5/20/5.5		42.5/20/5.5		42.5/20/5.5	
BASE STREAMFLOWS AT THE DALLES 10/										
Step I 30-yr Avg Streamflow, cfs and m^3/s	175120	4959	175084	4958	175084	4958	173390	4910	173390	4910
Step I CP Average, cfs and m^3/s	114518	3243	114487	3242	114487	3242	112665	3190	112665	3190
Step II CP Average, cfs and m^3/s	101396	2871	101376	2871	101376	2871	99211	2809	99211	2809
Step III CP Average, cfs and m^3/s	56034	1587	56088	1588	56088	1588	54698	1549	54698	1549
CAPACITY BENEFITS (MW)										
Step II CP Generation	8944.9		8951.5		8948.4		8902.8		8906.1	
Step III CP Generation	6898.7		6981.7		6974.5		6957.1		6978.0	
Step II Gain over Step III	2046.2		1969.9		1973.9		1945.7		1928.1	
CANADIAN ENTITLEMENT	1368.6		1332.3		1333.2		1304.1		1284.0	
Change due to Mica Reoperation	1.5		1.2		0.0		1.3		0.0	
ENERGY BENEFITS (aMW)										
Step II Annual Firm	8961.8		8960.1		8944.7		8999.4		8977.6	
Step II Thermal Displacement	2423.9		2383.9		2422.6		2407.8		2432.6	
Step II Remaining Usable Secondary	49.1		68.1		58.6		51.0		49.9	
Step II System Average Annual Usable	11434.8		11412.0		11425.8		11458.2		11460.1	
Step III Annual Firm	6300.7		6422.8		6354.9		6644.2		6621.0	
Step III Thermal Displacement	3879.6		3681.8		3800.3		3598.5		3633.4	
Step III Remaining Usable Secondary	294.7		330.0		309.8		265.4		260.7	
Step III System Average Annual Average	10475.1		10434.6		10465.1		10508.2		10515.1	
CANADIAN ENTITLEMENT 11/	479.9		488.7		484.0		475.0		472.5	
Change due to Mica Reoperation	9.9		3.7		3.7		1.3		1.3	
STEP II PEAK CAPABILITY (MW)	30944		28367		30163		29649		28785	
STEP II PEAK LOAD (MW)	29236		27306		29051		29014		28761	
STEP III PEAK CAPABILITY (MW)	30063		27703		28035		29105		28272	
STEP III PEAK LOAD (MW)	25158		23568		23992		25400		25168	

FOOTNOTES FOR TABLE 6

1. 100% x (January) / (average annual PNWA) firm loads (Table 1A, row 1(d)).

2. Average annual total firm exports (Table 1A, row 2(k)).

3. Absolute value of average annual total firm imports (Table 1A, row 3(i)).

4. Absolute value of average annual PNWA Non-Step I Hydro and Non-Thermal Resources (Table 1A, row 4(f)).

5. Average annual total Step I load (Table 1A, row 5).

6. Beginning with the 2006-07 DDPB, thermal installations include Columbia Generating Station and a generic thermal installation sized as needed to meet the Step I load. January thermal peak capability is shown (Table 1B, row 6(c)), which corresponds with the actual minimum peak surplus month (Table 1B, row 10(c)..

7. Average annual Energy from the thermal installations (Table 1A, row 6(c)).

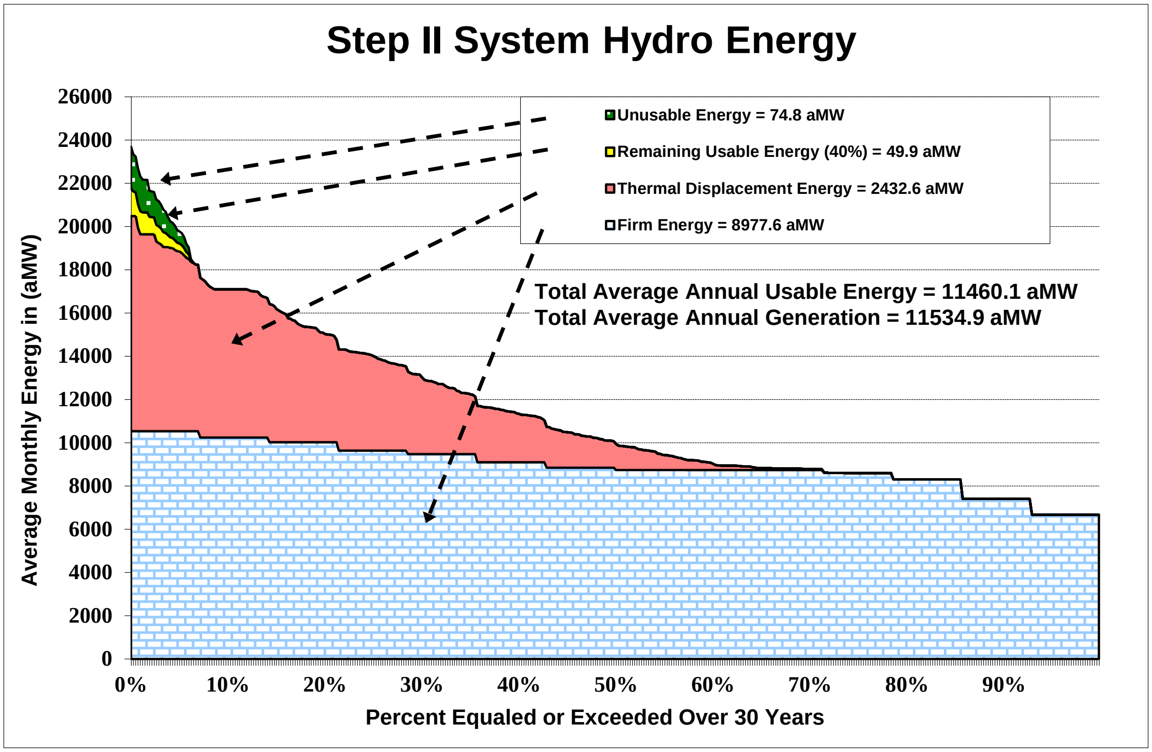
8. Average annual Step I Hydro Resources (Table 1A, row 7).

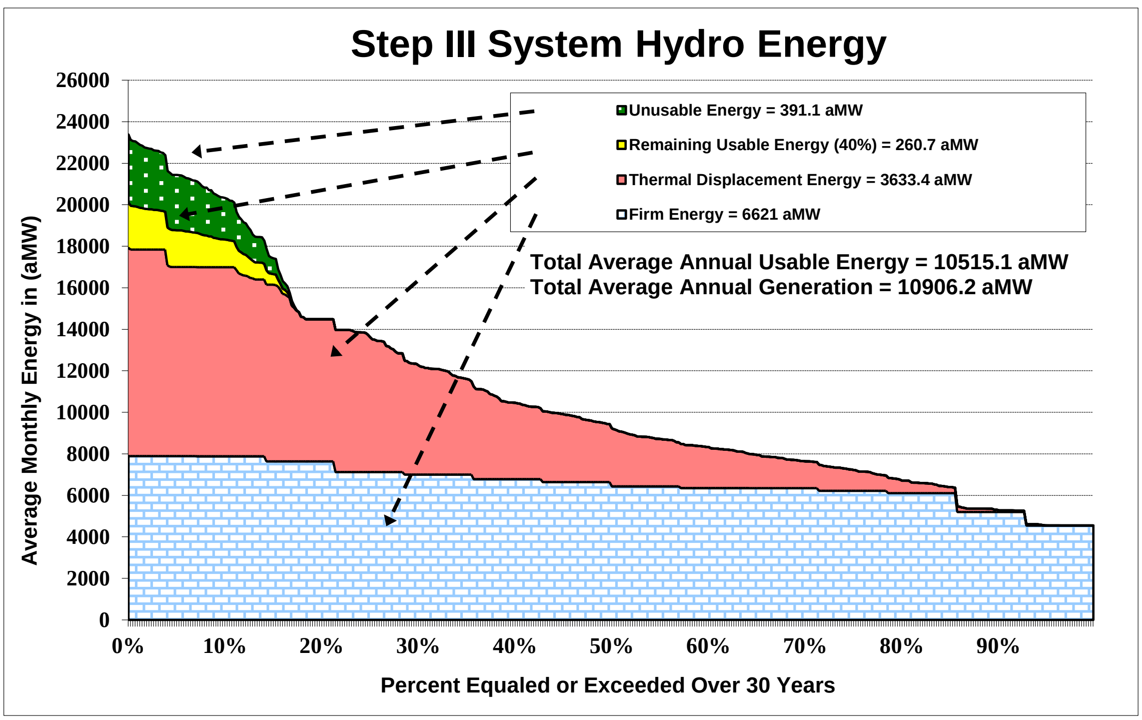
9. Average annual Step I Coordinated Hydro load (Table 1A, row 10).

10. The 2010 level modified streamflows were used beginning with the 2017-18 DDPB with adjustments for the Grand Coulee net pumping flows. The 2014-15, 2015-16 and 2016-17 DDPBs, based upon 2000 level modified streamflows, all include updated adjustments for the Grand Coulee gross pumping flows.

11. The energy benefits for 2014-15, 2015-16, and 2017-18 are all based upon Step II Joint Optimum and Step III U.S. Optimum 30-year hydro regulation studies. The energy benefits for 2016-17 are based upon 30-Year U.S. Optimum hydro regulation studies, which includes an adjustment (+3.7 aMW) to estimate the increase in the energy entitlement that would result from a Joint Optimum operation of the Step II study. The energy benefits for 2018-19 are estimated using the third streamline procedure based on the 2017-18 Step II Joint Optimum and Step III U.S. Optimum 30-year hydro regulation studies.

CHART 1
DURATION CURVES OF 30-YEAR MONTHLY HYDRO GENERATION
From the 19-42 and 19-13 Studies (Average monthly MW)





Values on chart above may differ from the values on Table 5 by as much as 0.1 aMW due to rounding error.