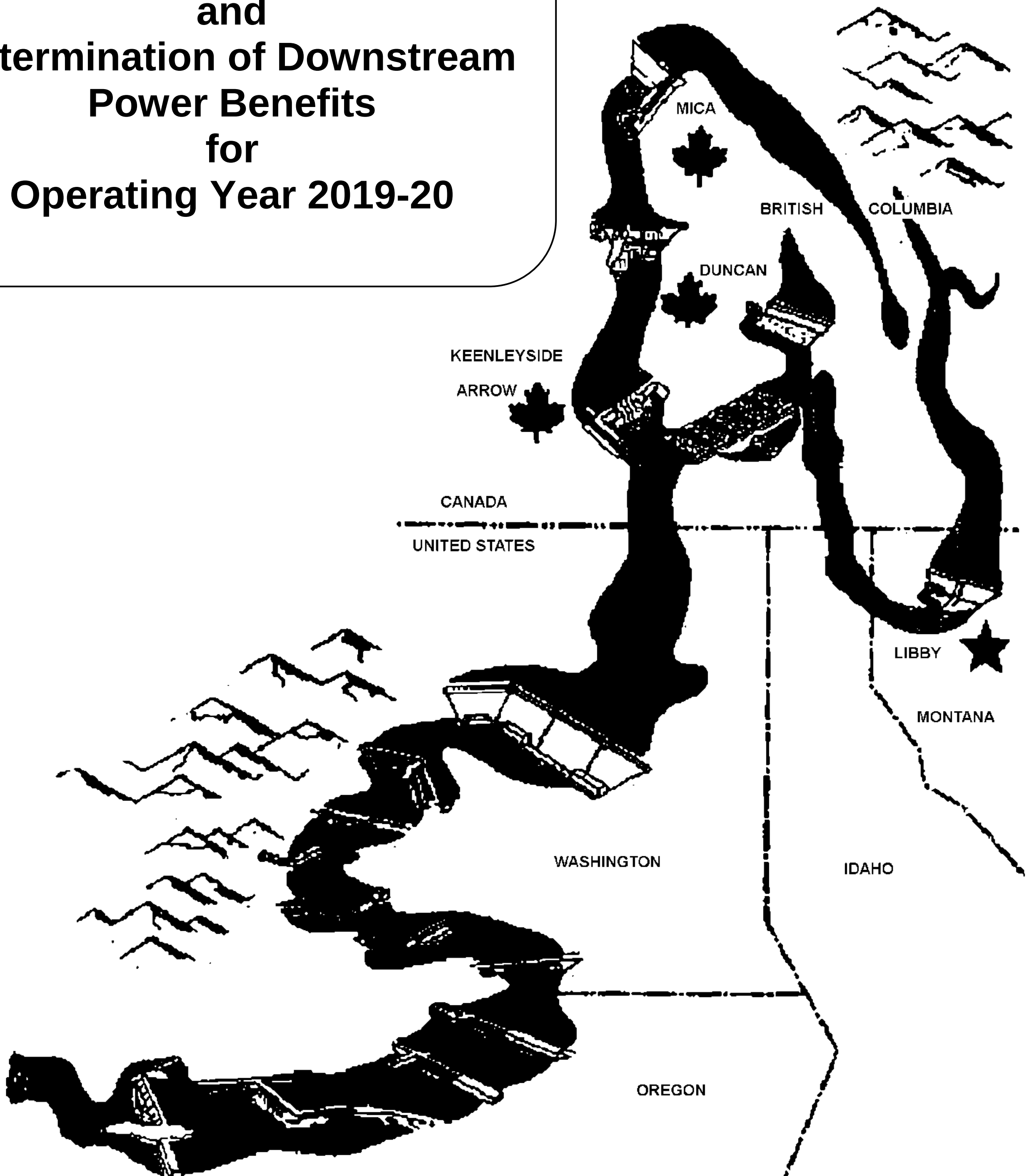
COLUMBIA RIVER TREATY
Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2019-20



Columbia River Treaty Operating Committee

January 2016

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COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR OPERATING YEAR 2019-20

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 2019-20" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2019-20," both dated January 2016, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the 2019-20 Operating Year.

The Entities also agree that nothing in the attached reports sets a precedent for future reports concerning the assured plan of operation for Canadian Treaty Storage and the resulting downstream power benefits. In addition, the assumptions, procedures and methodologies used in developing the attached reports do not establish, create or imply any precedent or binding position, resolution or agreement concerning assumptions, procedures or methodologies to be used in any future reports. The Entities also agree that nothing in the attached reports, the actions taken pursuant to these reports, or the approach used by the Entities and their representatives in preparing these reports shall be construed in the future as representing a past practice or procedure or constituting a Treaty modification or interpretation that prejudices, changes, or waives in any way Treaty rights and obligations.

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

Executed for the Canadian Entity this 5th day of Jan, 2016.

By: ______________________
Chris K. O'Riley
Chair

Executed for the United States Entity this 13th day of January, 2016.

By: ______________________
Elliot E. Mainzer
Chairman

By: ______________________
Brigadier General Scott A. Spellmon
Member

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COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 2019-20

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HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2019-20

January 2016

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 2019-20 (AOP20) 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.

Special terms used in this document, but not defined herein, have the meanings defined in the Treaty, Protocol, or the Entity Agreements referenced in this AOP. The Operating Committee has agreed, beginning with AOP20, to only publish system and project data and constraints in terms of Imperial units. This is in keeping with the usual practice of relying on these units for all operational purposes. This change was made in the Detailed Operating Plan (DOP) beginning with DOP15. Parallel publishing of SI (metric) units is being discontinued for purposes of both brevity and clarity. The system regulation studies and supporting data were based on Imperial units.

2. Development of the Assured Operating Plan

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 additions of Appendix 6 - Streamline Procedures; the October 2012 update to Appendix 7 - Table of Median Streamflows; and the September 2015 update to Appendix 8 - Hedges and Distributions. The POP is based on criteria contained in Annex A and Annex B of the Treaty, the Protocol, and the May 2003 Columbia River Treaty Flood Control Operating Plan (FCOP).

The following sections further describe procedures used in development of the AOP20.

a) <u>AOP20 - AOP24 Approach</u>

This AOP incorporates agreements reached by the Entities concerning certain procedures and related assumptions to be used only in AOP20 through AOP24 for the U.S. hydroelectric system modelled in the AOP/DDPB regulation studies. The Entities agreed that the AOP for the middle year, AOP22, would be completed in a detailed manner using all required assumptions and procedures to produce appropriate project operating criteria and to establish Canadian Entitlement amounts. It was further agreed that the results from the AOP22 studies would be used for the 2 prior years (AOP20 and AOP21) and for the 2 subsequent years (AOP23 and AOP24). This mid-point approach maintains Treaty principles, provides appropriate operating criteria, establishes Canadian Entitlement amounts, provides for timely completion of the AOPs for 2020-2024, and frees-up expertise and resources to work on developing AOP methodologies for the post-2024 period when the application of flood control provisions in the Treaty changes.

For this AOP, the Entities also have agreed to use the first of the three streamline procedures defined in Appendix 6 of the POP. This streamline procedure includes “Forecasting Loads and Resources” for determining the thermal installations, as described in Subsection 7(d) of this document. Section 7 of this document also describes how other procedures defined in the POP are being implemented in this AOP.

b) <u>Capacity Critical Procedures</u>

AOP20 incorporates capacity critical procedures. These procedures are, to the extent possible, as implemented in the “Entitlement Forecast Studies”, dated April 1993 and as described in POP. Because certain data have a more direct impact on the capacity calculations, a more thorough review of hydro plant capability, hydro maintenance and peak reserves was also undertaken. Both the Step I and II systems were determined to be capacity critical. For Step I, additional thermal installations were added to balance peak loads and resources. A surplus firm energy export (with no capacity) was also added to balance energy loads and resources. For Step II, critical head studies were performed in which peak hydro capacity was maximized by ensuring hydro projects do not draft below elevations where their capacity is reduced.

In addition, the capacity critical Step II system results in the Capacity Entitlement being limited by the Capacity Credit Limit. The Capacity Credit Limit is described in Treaty Annex B, paragraph 2, and in the Protocol, paragraph IX(2). These provisions specify that the capacity credit of Canadian Treaty Storage shall not exceed the difference between the firm load carrying capabilities of the projects and installations in the Step II and the Step III systems. The Capacity Credit Limit is also described in POP Section 3.3.A(2).

The Entities have agreed that the capacity critical procedures incorporated in AOP20, including in particular the application of the Capacity Credit Limit, do not prejudice or create a precedent for future AOPs.

c) System Regulation Studies

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 system regulation study[1].

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 U.S. Downstream power benefits were computed with the Canadian Treaty Storage operation based on the same criteria for joint optimum power generation as in the Step I study.

For AOP20 – AOP24, the Entities have agreed that the system regulation studies would be based on 2021-22 operating year estimated loads and resources in the U.S. Pacific Northwest Area (PNWA) including estimated flows of power from and to adjacent areas and hydro resources in the Columbia River Basin in British Columbia. These studies will hereafter be referred to as the AOP20 studies in this document.

In accordance with Protocol VIII, the AOP20 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[2] 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 U.S. The study indicated a 42.5 calendar-month critical period for the U.S. system resulting from the low flows during the period from 16 August 1928 through 29 February 1932. With the exception of Dworshak, it was assumed that all reservoirs, both in the U.S. 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). This is a change in name only, and has no effect on the procedures described in the FCOP or the URC data used in the studies. Historic documents that use the term “flood control” will not be changed. The FRM operation at Canadian projects was based on individual project risk management criteria instead of a composite curve. In accordance with Section 6-6 of the FCOP, a 4.08/3.6 million acre-feet (Maf) Mica/Arrow flood storage allocation was assumed. FRM and Variable Refill Curves are based on historical inflow volumes. Although only 15.5 Maf of usable storage are committed for power operation purposes under the Treaty, the FCOP provides for the full draft of the total 20.5 Maf of usable storage for on-call flood risk management purposes. As described in Subsection 3(d), FRM operations are implemented in the system regulation studies as URCs.

d) 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 U.S. (Joint Optimum), compared to an operation for optimum power only in the U.S. (U.S. 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 U.S.

To determine whether optimum power generation in both Canada and the U.S. 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 U.S. systems. The Canadian Treaty Storage operation in the Joint Optimum Study was designed to achieve a weighted sum of these three quantities that was greater than the weighted sum achieved in the U.S. Optimum Study.

In order to measure optimum power generation for the AOP20, 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

The sum of the three weighted quantities showed a net gain in the Joint Optimum Study compared to the U.S. 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 U.S. resulting from a change in operation to achieve a joint optimum operation. Separate Step II system regulation studies were developed reflecting: (i) Canadian Treaty Storage operation for optimum generation in the U.S. alone; and (ii) Canadian Treaty Storage operation for optimum generation in both Canada and the U.S. Using the storage operation for the optimum generation in both Canada and the U.S., there is a 7.1 aMW increase in the Canadian Entitlement for average annual usable energy and a 10.0 MW increase in the Canadian Entitlement for dependable capacity (as determined from the Capacity Credit Limit) compared to the operation for optimum generation in the U.S. alone. (See Table 5 of DDPB20, columns A and B.)

Since there is no reduction in entitlement, the Entities have determined in Section 4 of the DDPB20 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 2019-20 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). 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, and 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.

(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 Power Discharge Requirements (PDR) are determined in accordance with Section 2.3.B and the updated Appendix 1 of 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 of 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 80 Maf and 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 80 Maf, or greater than 110 Maf, the PDR values for 80 Maf and 110 Maf, respectively, are used. For AOP20, as since AOP12, the VRC Lower Limit (VRCLL) was applied as a fixed rule curve for Grand Coulee 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 2019-20, the PDRs and VRCLLs will be based on the forecast of unregulated runoff at The Dalles.

c) Operating Rule Curve Lower Limits (ORCLLs)

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 Risk Management Storage Reservation Diagrams (SRDs) contained in the FCOP and analysis of system flood risk management 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 risk management space in Mica and Arrow to maximum drafts of 4.08 Maf and 3.6 Maf, respectively. In actual operation, 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 U.S. system 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 stream flow period are included in Table 10 to illustrate the probable future range of these curves based on historical water conditions.

4. Operating Rules

The system regulation study storage operation results for the whole of Canadian Treaty Storage for the 30-year stream flow 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.

The following rules and other operating criteria included in the AOP20 system regulation study will apply to the operation of Canadian Treaty Storage in the 2019-20 Operating Year, subject to the provisions under Section 5.

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 U.S. 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 U.S. 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 U.S. 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 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 from Arrow to the extent possible.

Mica storage releases in excess of 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 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 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 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 AOP20 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 is 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 and minimum outflows apply from February to June depending on the forecast for The Dalles unregulated runoff. In February and March the January through July volume forecast at The Dalles is used and in April through June the April through July volume forecast at The Dalles is used. The maximum outflow limits apply under all water conditions, subject to flood risk management requirements and a maximum combined draft of 14.1 Maf at Mica + Arrow. In no circumstance shall the minimum outflow be reduced below the Treaty specified minimum of 5,000 cfs. The maximum storage limits, maximum outflow limits and minimum outflow limits for the 30-year historical streamflow record used in the AOP20 Step I study are shown in Table 1.1(b) and 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 AOP20 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 prior AOPs.

5. <u>Preparation of the Detailed Operating Plan</u>

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 2019-20 DOP (DOP20) 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 DOP20. Failing agreement on updating the data and/or criteria, the DOP20 for Canadian Treaty Storage shall include the rule curves, Mica and Arrow operating criteria, and other data and criteria provided in this AOP. During the 2019-20 Operating Year actual operation of Canadian Treaty Storage shall be guided by the DOP20.

The values used in the AOP studies 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 stream flow 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. Canadian Treaty Storage refill limits will be computed on a day-by-day basis, consistent with the FCOP, using the residual inflow volume forecasts depleted by the volume required for minimum outflow, unless higher monthly project discharges are required to meet the U.S. system FELCC in the TSR, 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 2019-2020."

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[3]. This arrangement covers the full 1 August 2019 through 31 July 2020 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 2018-19 AOP and Notable Assumptions

Data from the recent AOPs are compared and summarized in Table 12. As described in Subsection 2(a), the Entities have agreed that the AOP20 – AOP24 studies would be based on the AOP22, including all load and resource assumptions and procedures and hydroregulation studies. As a result, the following explanations of important changes and notable assumptions are relative to the AOP19. An explanation of the more important changes and notable assumptions follows.

a) Pacific Northwest Area (PNWA) Firm Load

Loads for the AOP20 are based on Bonneville Power Administration's (BPA) January 2015 White Book (WB14)[4] expected load forecast for 2021-22. The WB14 forecast for the 2021-22 regional firm load is 23,889 annual aMW, which is 341 aMW higher than the AOP19. There were minor changes to the Idaho portion of the Rocky Mountain Power (formerly known as Utah Power and Light) load and to the Coulee pumping requirements, leading to an increase in the net PNWA firm load by 326 annual aMW from the AOP19 to AOP20.

The average critical period load factor increased from 75.08% in AOP19 to 76.68% in AOP20. 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 AOP20, the estimates of the amount of Canadian Entitlement energy and other uncommitted imports that would be assumed to serve load in the PNWA were based on procedures that have been developed for and since the AOP13. These procedures were developed because the WB is an inventory study of committed and uncommitted loads and resources and does not balance loads and resources. As such, monthly firm WB deficits are balanced by an allocation of imports that are reflected in the estimated flows of power at points of interconnection.

- The first step of this procedure is to calculate the monthly WB14 firm energy and capacity deficits with PNWA utility planned resources, but without uncommitted resources. Next, the remaining monthly deficits are eliminated by proportionately allocating uncommitted PNWA resources and Canadian Entitlement for both energy and capacity based on their respective availability. The available Canadian Entitlement was the estimated AOP20 Canadian Entitlement reduced by transmission losses with a further adjustment for Entitlement capacity assumed to be used in Canada as per BC Hydro's resource plan. Lastly, any remaining monthly deficits are met with California imports assumed to be available per the assumptions of the Northwest Power Council's Resource Adequacy Advisory Committee. This procedure differs somewhat from that in AOP19. In AOP19, the Canadian Entitlement energy was allocated as described, but the full Canadian Entitlement capacity was assumed along with the energy, rather than allocating the Canadian Entitlement capacity independently from the Canadian Entitlement energy.

- For the AOP20, this procedure resulted in 17% (73 annual aMW) of the available Canadian Entitlement energy and 398 annual aMW of uncommitted PNWA resources being used for serving PNWA load. No imports from California were necessary to balance WB loads and resources. In the peak-critical month of January, 631 MW or 57% of the Capacity Entitlement and 1919 MW of uncommitted PNWA resources were used for serving PNWA peak loads. The resulting amount of allocated imports are included in the Step I load/resource balance. Compared to AOP19, this procedure results in a 98 annual aMW decrease in Canadian Entitlement energy and a 664 MW decrease in Canadian Entitlement capacity serving load in the U.S. The large decrease in capacity is due to the change in the treatment of the capacity as described in the previous paragraph.

The estimated Canadian Entitlement included in export loads was 431 annual aMW of energy and 1112 MW of capacity delivered at the Canada – U.S. border. The amount computed for the DDPB20 is 454.3 annual aMW of energy and 1141.5 MW of capacity before losses (438 annual aMW of energy and 1120 MW of capacity at the border after losses). 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.

As described in Subsection 7(d), the addition of generic Thermal Installations to bring the Step I system into peak load/resource balance resulted in 1140 annual aMW of surplus firm energy. As agreed in the 1988 Entity Agreements and described in POP Section 3.2.B(2), the surplus firm energy is shown as an export out of the PNWA and, in this AOP, is assumed to be a uniform monthly energy delivery with no capacity.

Compared to the AOP19, power flows-out (exports that are mostly to the southwest but also include the Entitlement) increased by 777 annual aMW primarily as a result of the uniform export of the AOP firm energy surplus. Power flows-in (imports) decreased by 265 annual aMW due to the removal of the seasonal exchange for AOP Hydro and the decreased import of the Canadian Entitlement for WB deficits.

c) <u>Non-Step I Hydro and Other Non-Thermal Resources</u>

The Step I System Load is reduced by hydro-independent generation, non-Step I coordinated hydro, and miscellaneous non-thermal resources. For the AOP20, these resources, which include firm wind, increased by 24 annual aMW from the AOP19, primarily due to a slight increase in renewables.

d) <u>Thermal Installations</u>

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 (2020-21 and 2021-22) maintenance cycle at CGS was used, which resulted in an increase of 41 annual aMW of energy and no change in January peak capacity for AOP20 compared to AOP19.

For the AOP20, it was agreed that the shape of the generic thermal installation would be determined from the shape of the committed WB14 large thermal, co-generation, and combustion turbines without CGS and independent power producers. In prior AOPs, this shape had included uncommitted thermal and 30% of unreported CT capability. The 30% of unreported CT capability is no longer included because the WB14 reports thermal plants at their full plant capability.

In AOP20, the Step I system when balanced on energy resulted in a January 1932 peak deficit of 1313 MW. The generic Thermal Installation was increased to bring the Step I system into peak load/resource balance with a resulting annual average firm energy surplus of 1140 aMW.

The total thermal installations increased by 1338 annual aMW from AOP19 to AOP20, as shown in DDPB Section 7(b), primarily due to the increased generic thermal needed to balance the peak January 1932 deficit.

e) <u>Hydro Project Modified Streamflows</u>

The unregulated base streamflows used in the system regulation studies were updated to the 2010 Modified Streamflows 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. Additionally, the flows were further adjusted to include net Grand Coulee pumping updates from the PNCA 1 February 2015 data submittal.

f) <u>Hydro Project Rule Curves</u>

Because the Entities have agreed that the AOP20 – AOP24 system regulation studies would be based on AOP22, the AOP20 uses the same hydro project rule curves as the AOP22, in which full Step I, II, and III hydro regulation studies were performed per the 2003 Principles and Procedures document. Changes and notable assumptions from the AOP19 include:

- The use of a fixed VRCLL at Grand Coulee only, equal to the ORCLL for January and February, and based on historic minimum elevations for firm power operation for March to June, including 1225.0 feet for March to April, 1240.0 feet for May, and 1285.0 feet for June. The VRCLL for March through June were updated due to changes in the Storage vs Elevation tables at Grand Coulee (Steps I and II) as reflected in the 1 February 2015 PNCA data submittal;

- The URC flood risk management data was developed by the Corps of Engineers using the 2010 Modified Streamflows, consistent with current AOP operating criteria (including 4.08/3.6 Maf Mica/Arrow flood storage allocation, Libby standard flood risk management, Hungry Horse variable flood risk management, 1998 Brownlee procedures, and no Dworshak/Brownlee shift) and in coordination with all Treaty parties. Studies assumed the 1938 IJC Order on Kootenay Lake does not affect Libby or Duncan operation, and both projects will be regulated to their flood risk management curves as required by their SRDs . Grand Coulee URCs were adjusted by the Corps of Engineers to reflect updated reservoir storage data based on the Bureau of Reclamation's 2010-11 survey of Franklin D. Roosevelt Lake. The Duncan end-of-February flood risk management rule curve was limited to no lower than 1812.5 feet (93.1 ksfd usable storage), in accordance with the SRD updated November 2009;

- Monthly distribution factors based on the 2010 Modified Flows were updated as approved in the May 2012 Columbia River Treaty Operating Committee (CRTOC) meeting;

- Hedges (also called forecast errors) for Libby and other projects were updated as reflected in the POP document, Appendix 8 update approved in the September 2015 CRTOC meeting;

- For the AOP20 Critical Period Study, the March ARC contents at Grand Coulee are 2343.1 ksfd and 2286.4 ksfd for Steps I and II, respectively.

These March ARC storage limits were based on the average of the AOP12, 14 and 15 ARCs from the ARC optimization study, and are limited by flood risk management constraints. Up to the AOP15, the March ARCs were calculated using the final ARCs from the previous AOP study. However, from AOP11 to AOP15, this procedure resulted in significant year-to-year reductions in the March ARC contents at Grand Coulee, which may potentially reduce system firm and secondary energy. The revised procedure from AOP16 was intended to avoid this impact;

- To save time, Composite Canadian crossovers during September through January between the second and third year of the Step I Critical Period were left in the U.S. Optimum study as agreed by both Entities; and

- The Refill Study was performed for each Step of the AOP20. PDRs were developed by the Corps of Engineers using the Corps' HYSSR model for each cyclic reservoir contained in the study, starting with minimum flows and increasing PDRs for individual projects as needed to pass the Refill Test.

g) <u>Other Hydro Project Operating Procedures, Constraints, and Plant Data</u>

The AOP20 hydro project operating procedures, constraints and plant data were updated from the PNCA 1 February 2013 through and 2015 data submittals in accordance with POP procedures, except as noted below.

The nonpower requirements for Base System projects were agreed to in the 29 August 1996 Entity Agreement. These requirements are essentially the nonpower requirements included in the 1979-80 and prior AOP/DDPB studies. Nonpower constraints for non-Base System projects are updated to current requirements, except for Libby, which uses the values specified in the February 2000 Libby Coordination Agreement. Some notable assumptions include:

- Brownlee no longer has an at-site minimum flow requirement but is required to support a year-round flow of 6500 cfs at Hells Canyon for navigation purposes, based on the 1988 Agreement between the Corps of Engineers and Idaho Power Company as well as the proposed license modeling criteria of the Hells Canyon FERC license application. In addition, the Brownlee operation was refined in Step I by starting the Critical Period full and operating to a two-foot draft from normal full through December to enhance power operations. This operation was carried over to Steps II and III;

- Dworshak is operated to a minimum flow or flood risk management criteria October through May, and a target operation June through September to obtain uniform outflows July through August;

- Hungry Horse is operated to a maximum flow of 9500 cfs for Step I to reflect transmission constraints with Libby;

- Grand Coulee storage-elevation tables were updated to reflect increased storage capacity as a result of bathymetry studies completed in 2010-2011 on Lake Roosevelt. The new tables showed an increase of 0.164 Maf in active capacity at elevation 1290 feet compared to the previous table. Elevation changes ranged from a few tenths in the upper reservoir to 3 feet at the bottom.

- The 30-year storage operation at Mossyrock, Cushman #1, Alder, Swift #1, Merwin, Yale, and Timothy was set to a fixed operation (first coded) from AOP06 because they are no longer coordinated resources in PNCA Planning. Although included in the Step I hydro regulation model, these projects are now essentially the same as a hydro-independent project;

- The Head vs. Generation per Flow table (H/K) was updated for Round Butte (Step I) per the 1 February 2012 PNCA data submittal. The H/K tables were updated for Chelan (Steps I, II, and III) per the 1 February 2014 PNCA data submittal. In addition, the H/K tables were updated for Mica (Steps I and II) per the 1 February 2015 PNCA data submittal;

- Project Limits tables (LT) were updated for Chelan (Steps I, II, and III) per the 1 February 2014 PNCA data submittal. In addition, the Project Limits tables were updated for Grand Coulee (Steps I, II, and III) to accommodate modeling the new ES tables from the 1 February 2015 PNCA data submittal;

- Discharge vs. Generation tables (GD) were updated in Step I for Faraday, North Fork, Pelton, and River Mill per the 1 February 2012 PNCA data submittal. In addition, the GD tables were updated for Waneta (Steps I, II, and III) per the 1 February 2015 PNCA data submittal;

- Discharge vs. Spill tables (SD) were updated in Step I for Faraday, North Fork, Pelton, and River Mill per the 1 February 2012 PNCA data submittal. In addition, the SD tables were updated for Waneta (Steps I, II, and III) per the 1 February 2015 PNCA data submittal;

- Storage vs Maximum Discharge tables (MD) were updated for Chelan (Steps I, II, and III) per the 1 February 2014 PNCA data submittal. Later, the MD tables were updated for Grand Coulee (Steps I, II, and III) to accommodate modeling the new ES tables from the 1 February 2015 PNCA data submittal. In addition, the MD tables were updated for Mica (Steps I and II) per the 1 February 2015 PNCA data submittal;

- Head vs. Maximum Generation tables (MG) were updated for Chelan (Steps I, II and III) per the 1 February 2014 PNCA data submittal. In addition, the MG tables were updated for Mica (Steps I and II) per the 1 February 2015 PNCA data submittal;

- The Storage limits table in Step I was updated for Lower Baker (max store in Step I) and for Upper Baker (max and min store in Step I) per the 1 February 2013 PNCA data submittal. An update for Ross (removal of a min store in Step I) was included per instructions from Seattle City Light (the Project's Owner). In addition, the Storage Limits tables were updated for Grand Coulee (Steps I, II, and III) to accommodate modeling the new ES tables from the 1 February 2015 PNCA data submittal;

- The Flow Limits table was updated for Gorge (min flow in Step I) and for Lower Baker (max flow in Step I) per the 1 February 2013 PNCA data submittal. Later, an update for Merwin (min flow in Step I) was included per instructions from PacifiCorp (the Project's Owner) concerning the Project's FERC license. In addition, the Flow Limits table was updated for Lower Baker (max and min flow in Step I) per the 1 February 2014 PNCA data submittal;

- The Spill Limits table was adjusted for Little Goose (min fish spill in Step 1) to more closely match the 1 Febrary 2012 PNCA data submittal. In addition, the Spill Limits tables were updated in Step I for Lower Monumental and Lower Granite per the 1 February 2014 PNCA data submittal; and

- Hydro-independent projects were updated for the 2010 Modified Flows, resulting in slightly lower average generation.

As described in Subsection 2(b), AOP20 is capacity critical in both the Step I and Step II systems. Because hydro plant capability, hydro maintenance, and peak reserves have a more direct impact on capacity calculations, the Entities reviewed those aspects of these studies with the following results.

- Peak capability data were updated for Wanapum and Priest Rapids based on information from the project owner;

- Peak capability data for McNary, John Day, The Dalles, and Bonneville were updated based on the most-recently available data from BPA and the Corps of Engineers;

- Hydro maintenance data were reviewed by the US Entity on a plant-by-plant basis. Based on this review, the Entities agreed upon a maintenance schedule as a percentage of the capability of the projects in aggregate. Different percentages were used in Step I as compared to Steps II and III to reflect the maintenance at the projects within each system; and

- Peak reserves were updated from 1993 studies using the PNCA Loss of Load probability method. Peak reserves were calculated to be 12.7% of load.

End Notes

1 "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 22-41," dated 18 November 2015.

2 Bonneville Power Administration (BPA) (2011). 2010 Level Modified Streamflow, 1928-2008. DOE/BP-4352. Portland, Oregon.

3 "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.

4 January 2015 "2014 Pacific Northwest Loads & Resources Study".

Table 1
Mica Project Operating Criteria
2019-20 Assured Operating Plan

		Target Operation		Target Operation Limits		
Month	End of Previous Month **Arrow** Storage Content (ksfd)	Month Average Outflow (cfs)	End-of-Month Treaty Storage Content 1/ (ksfd)	Minimum Treaty Storage Content 2/ (ksfd)	Maximum Outflow 1/ (cfs)	Minimum Outflow (cfs)
August 1-15	3,570 - FULL	-	3,494.1	-	54,000	15,000
	3,200 - 3,570	25,000	-	0	-	15,000
	2,100 - 3,200	27,000	-	0	-	15,000
	0 - 2,100	44,000	-	0	-	15,000
August 16-31	3,530 - FULL	-	3,529.2	-	54,000	15,000
	3,280 - 3,530	32,000	-	0	-	15,000
	2,700 - 3,280	40,000	-	0	-	15,000
	0 - 2,700	44,000	-	0	-	15,000
September	3,570 - FULL	-	3,454.1	-	54,000	10,000
	1,730 - 3,570	27,000	-	0	-	10,000
	1,640 - 1,730	32,000	-	0	-	10,000
	0 - 1,640	36,000	-	0	-	10,000
October	3,060 - FULL	-	3,394.1	-	54,000	10,000
	2,500 - 3,060	14,000	-	0	-	10,000
	1,410 - 2,500	19,000	-	0	-	10,000
	0 - 1,410	21,000	-	0	-	10,000
November	3,040 - FULL	16,000	-	0	-	12,000
	2,980 - 3,040	23,000	-	0	-	12,000
	2,960 - 2,980	30,000	-	0	-	12,000
	0 - 2,960	32,000	-	0	-	12,000
December	2,670 - FULL	28,000	-	204.1	-	14,000
	2,570 - 2,670	31,000	-	204.1	-	14,000
	2,200 - 2,570	32,000	-	204.1	-	14,000
	0 - 2,200	34,000	-	204.1	-	14,000
January	1,830 - FULL	28,000	-	204.1	-	14,000
	1,800 - 1,830	36,000	-	204.1	-	14,000
	0 - 1,800	44,000	-	204.1	-	14,000
February	1,170 - FULL	24,000	-	0	-	12,000
	600 - 1,170	31,000	-	0	-	12,000
	0 - 600	36,000	-	0	-	12,000
March	880 - FULL	10,000	-	0	-	12,000
	320 - 880	12,000	-	0	-	12,000
	250 - 320	14,000	-	0	-	12,000
	0 - 250	26,000	-	0	-	12,000
April 1-15	600 - FULL	10,000	-	0	-	12,000
	200 - 600	12,000	-	0	-	12,000
	50 - 200	14,000	-	0	-	12,000
	0 - 50	26,000	-	0	-	12,000
April 16-30	290 - FULL	10,000	-	0	-	10,000
	80 - 290	14,000	-	0	-	10,000
	0 - 80	18,000	-	0	-	10,000
May	150 - FULL	8,000	-	0	-	8,000
	70 - 150	14,000	-	0	-	8,000
	0 - 70	21,000	-	0	-	8,000
June	1,370 - FULL	8,000	-	0	-	8,000
	1,100 - 1,370	10,000	-	0	-	8,000
	970 - 1,100	13,000	-	0	-	8,000
	0 - 970	16,000	-	0	-	8,000
July	3,360 - FULL	-	3,374.1	-	54,000	10,000
	2,400 - 3,360	10,000	-	0	-	10,000
	2,200 - 2,400	20,000	-	0	-	10,000
	0 - 2,200	32,000	-	0	-	10,000

1/ If the Mica target end-of-month storage content is less than 3,529.2 ksfd, then a maximum outflow of 54,000 cfs will apply.
2/ Mica outflows will be reduced to the lesser of the target outflow and the minimum outflow to maintain the reservoir above the minimum Treaty storage content.

Table 1.1a
Arrow Project Operating Criteria: Definition
2019-20 Assured Operating Plan

Period	Volume Runoff Period	The Dalles Volume Runoff (Maf)	Maximum Storage Limit 1/ 2/ (ksfd)	Minimum Outflow Limit 2/ 3/ (cfs)	Maximum Outflow Limit 4/ (cfs)
August 15 - December	-		URC	10,000	-
January	-		URC	10,000	70,000
February	Jan-Jul	≤ 90	URC	10,000	60,000
		>90 to <100	URC to 1,500.0	10,000 to 20,000	
		≥ 100	1,500.0	20,000	
March	Jan-Jul	≤ 90	URC	10,000	-
		>90 to <100	URC to 1,200.0	10,000 to 20,000	
		≥ 100	1,200.0	20,000	
April 15	Apr-Jul	≤ 70	URC	10,000	-
		>70 to <80	URC to 900.0	10,000 to 15,000	
		≥ 80	900.0	15,000	
April 30	Apr-Jul	≤ 70	URC	10,000	-
		>70 to <80	URC to 1,000.0	10,000 to 15,000	
		≥ 80	1,000.0	15,000	
May	Apr-Jul	≤ 70	URC	5,000	-
		>70 to <80	URC to 2,600.0	5,000 to 10,000	
		≥ 80	2,600.0	10,000	
June	Apr-Jul	≤ 70	URC	5,000	-
		>70 to <80	URC to 3,300.0	5,000 to 10,000	
		≥ 80	3,300.0	10,000	
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 if The Dalles volume runoff is between the two threshold values. For example, if the January-July volume runoff is between 90 Maf and 100 Maf, then the February Maximum Storage Limit is interpolated between the URC and 1,500 ksfd, and the Minimum Outflow Limit is interpolated between 10,000 and 20,000 cfs

3/ 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.

4/ The Maximum Average Monthly Outflow Limit applies over all water conditions and takes precedence over the Maximum Storage Limit. However, the Maximum Outflow Limit may be exceeded to avoid storage above the URC.

Table 1.1b
Arrow Project Operating Criteria: 30-Year Operating Data
End-of-Period Maximum Storage Limit (ksfd)
2019-20 Assured Operating Plan

	AUG15-DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	-	-	URC	URC	URC	URC	URC	URC	-
1929-30	-	-	"	"	"	"	"	"	-
1930-31	-	-	"	"	"	"	"	"	-
1931-32	-	-	1,500.0	1,200.0	900.0	1,000.0	"	3,300.0	-
1932-33	-	-	"	"	"	"	"	URC	-
1933-34	-	-	"	"	"	"	"	3,300.0	-
1934-35	-	-	2,115.5	1,653.0	1,309.8	1,362.4	"	3,432.5	-
1935-36	-	-	2,247.5	1,754.1	1,080.3	1,183.3	2,707.0	3,358.3	-
1936-37	-	-	URC	URC	URC	URC	URC	URC	-
1937-38	-	-	1,500.0	1,200.0	900.0	1,000.0	"	3,300.0	-
1938-39	-	-	URC	URC	URC	URC	"	URC	-
1939-40	-	-	"	"	"	"	"	"	-
1940-41	-	-	"	"	"	"	"	"	-
1941-42	-	-	2,111.6	1,650.1	1,287.2	1,342.4	"	"	-
1942-43	-	-	1,500.0	1,200.0	900.0	1,000.0	"	3,300.0	-
1943-44	-	-	URC	URC	URC	URC	"	URC	-
1944-45	-	-	"	"	"	"	"	"	-
1945-46	-	-	1,500.0	1,200.0	900.0	1,000.0	"	3,300.0	-
1946-47	-	-	"	"	"	"	"	"	-
1947-48	-	-	"	"	"	"	"	"	-
1948-49	-	-	"	"	"	"	2,600.0	"	-
1949-50	-	-	"	"	"	"	URC	URC	-
1950-51	-	-	"	"	"	"	"	3,300.0	-
1951-52	-	-	"	"	"	"	2,600.0	"	-
1952-53	-	-	"	"	"	"	URC	"	-
1953-54	-	-	"	"	"	"	"	URC	-
1954-55	-	-	1,682.5	1,334.3	"	"	"	3,300.0	-
1955-56	-	-	1,500.0	1,200.0	"	"	"	"	-
1956-57	-	-	"	"	"	"	2,600.0	"	-
1957-58	-	-	"	"	"	"	"	"	-

Table 1.1c
Arrow Project Operating Criteria: 30-Year Operating Data
Period Average Outflow Limits (cfs)
2019-20 Assured Operating Plan

	AUG15-DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
Maximum Outflow Limits									
		70,000	60,000						
Minimum Outflow Limits									
1928-29	10,000	10,000	10,000	10,000	10,000	10,000	5,000	5,000	10,000
1929-30	"	"	"	"	"	"	"	"	"
1930-31	"	"	"	"	"	"	"	"	"
1931-32	"	"	20,000	20,000	15,000	15,000	10,000	10,000	"
1932-33	"	"	"	"	"	"	"	"	"
1933-34	"	"	"	"	"	"	"	"	"
1934-35	"	"	11,977	11,977	12,630	12,630	7,630	7,630	"
1935-36	"	"	10,186	10,186	13,957	13,957	8,957	8,957	"
1936-37	"	"	10,000	10,000	10,000	10,000	5,000	5,000	"
1937-38	"	"	20,000	20,000	15,000	15,000	10,000	10,000	"
1938-39	"	"	10,000	10,000	10,000	10,000	5,000	5,000	"
1939-40	"	"	"	"	"	"	"	"	"
1940-41	"	"	"	"	"	"	"	"	"
1941-42	"	"	12,028	12,028	12,761	12,761	7,761	7,761	"
1942-43	"	"	20,000	20,000	15,000	15,000	10,000	10,000	"
1943-44	"	"	10,000	10,000	10,000	10,000	5,000	5,000	"
1944-45	"	"	"	"	"	"	"	"	"
1945-46	"	"	20,000	20,000	15,000	15,000	10,000	10,000	"
1946-47	"	"	"	"	"	"	"	"	"
1947-48	"	"	"	"	"	"	"	"	"
1948-49	"	"	"	"	"	"	"	"	"
1949-50	"	"	"	"	"	"	"	"	"
1950-51	"	"	"	"	"	"	"	"	"
1951-52	"	"	"	"	"	"	"	"	"
1952-53	"	"	"	"	"	"	"	"	"
1953-54	"	"	"	"	"	"	"	"	"
1954-55	"	"	17,622	17,622	"	"	"	"	"
1955-56	"	"	20,000	20,000	"	"	"	"	"
1956-57	"	"	"	"	"	"	"	"	"
1957-58	"	"	"	"	"	"	"	"	"

Table 2
Comparison of Assured Operating Plan Study Results
2019-20 Assured Operating Plan

Study 22-41 provides Optimum Generation in Canada and in the United States.
Study 22-11 provides Optimum Generation in the United States only.

		Study No. 22-41	Study No. 22-11	Net Gain	Weight	Value
1 Firm Energy Capability (aMW)						
US System	1/	11826.9	11826.0	0.9		
Canada	2/, 3/	3096.1	3070.0	26.1		
		14923.0	14896.0	27.0	3	80.9
2 Dependable Peaking Capacity (MW)						
US System	4/	29922.5	29868.5	54.0		
Canada	2/, 5/	7783.1	7773.8	9.3		
		37705.6	37642.3	63.4	1	63.4
3 Average Annual Usable Secondary Energy (aMW)						
US System	6/	3300.8	3273.0	27.9		
Canada	2/, 7/	332.5	358.2	-25.7		
		3633.3	3631.2	2.1	2	4.2
					Net Change in Value =	148.5

1/ US system firm energy capability was determined over the US system critical period beginning August 16, 1928 and ending February 29, 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 October 1, 1940 and ending April 30, 1946.
4/ US system dependable peaking capability was determined from January 1932.
5/ Canadian system dependable peaking capability was determined from December 1944.
6/ US system 30-year average secondary energy limited to secondary market.
7/ Canadian system 30 year average generation minus firm energy capability.

Table 3
Critical Rule Curves
End-of-Period Treaty Storage Contents (ksfd)
2019-20 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	3332.8	3333.8	2984.8	2336.5	1312.3	491.6	495.9	483.6	406.1	868.0	2515.3	3465.3
1929-30	3514.6	3486.5	3298.5	2940.3	2295.0	1583.4	386.3	129.2	0.0	0.0	220.2	871.2	2211.3	3164.6
1930-31	3388.5	3418.8	3277.8	2955.6	2439.3	1652.6	750.8	121.8	0.0	0.0	0.0	689.6	1868.0	2444.6
1931-32	2307.3	2240.3	1969.8	1607.0	1093.9	220.5	0.0	0.0						
							ARROW							
1928-29	3579.6	3579.5	3503.5	3322.6	2876.8	2321.1	1493.9	820.4	709.4	688.8	685.4	1602.7	3141.5	3451.5
1929-30	3579.6	3535.6	3180.1	2790.8	2021.1	1506.8	776.1	137.7	0.0	171.4	549.5	1647.0	2657.3	3486.1
1930-31	3579.6	3579.6	3325.2	2947.1	2266.8	1537.1	751.4	341.3	0.3	0.3	0.3	814.0	1817.4	2064.8
1931-32	1933.2	1790.1	1562.2	1347.4	515.9	0.0	0.4	0.0						
							DUNCAN							
1928-29	705.8	705.8	600.0	575.0	525.0	400.0	200.0	85.2	94.2	99.7	111.0	228.5	503.3	690.2
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	0.0	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	7814.5	7436.3	7231.4	6386.6	5057.6	3006.2	1397.2	1299.5	1272.1	1202.5	2699.2	6160.1	7607.0
1929-30	7794.2	7697.1	7028.6	6231.1	4766.1	3390.2	1262.4	341.9	0.0	184.8	816.2	2679.7	5249.7	7200.7
1930-31	7568.1	7598.4	7128.0	6352.7	5106.1	3389.7	1577.2	488.1	0.3	0.3	0.3	1660.8	4080.5	5009.4
1931-32	4790.5	4580.4	3982.0	3304.4	1759.8	220.5	0.4	0.0						

Note: Individual project rule curves are input to the AOP20 Step 1 study and adjusted to eliminate any Canadian composite crossovers according to Subsection 3(a) of this AOP20 document.

Table 4
Mica Assured and Variable Refill Curves
Distribution Factors, Forecast Errors, Power Discharge Requirements,
and Operating Rule Curve Lower Limits
2019-20 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	280.6	459.0	524.0	540.3	534.9	523.3	529.9	555.0	618.3	1377.4	2613.0	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							1747.8	1566.6	1509.6	1501.8	1545.6	2057.6	2887.1	3529.2
1929-30							724.4	502.9	437.4	447.8	607.9	1453.8	2597.0	"
1930-31							982.6	770.3	699.9	688.6	782.4	1472.7	2673.3	"
1931-32							476.3	270.7	207.5	197.0	318.1	1120.7	2492.2	"
1932-33							382.7	212.6	166.7	154.1	235.6	1020.0	2326.0	"
1933-34							0.0	0.0	0.0	0.0	0.0	767.0	2583.1	"
1934-35							663.5	474.8	440.9	448.3	522.1	1236.1	2417.6	"
1935-36							450.8	262.4	217.4	204.4	303.3	1187.7	2689.1	"
1936-37							1734.6	1532.7	1460.9	1442.2	1534.1	2069.8	2919.4	"
1937-38							755.5	567.0	503.5	497.5	594.1	1344.0	2586.0	"
1938-39							779.5	635.5	579.2	593.8	708.5	1488.1	2903.0	"
1939-40							560.7	379.6	341.0	349.5	482.8	1285.3	2658.2	"
1940-41							1167.9	976.4	925.3	933.3	1113.6	1849.6	2901.1	"
1941-42							1164.2	976.6	917.3	902.1	981.5	1652.4	2753.5	"
1942-43							1393.1	1183.0	1120.5	1105.1	1260.5	1969.2	2829.5	"
1943-44							1840.4	1622.9	1564.6	1555.0	1626.3	2179.0	3062.1	"
1944-45							1754.2	1573.7	1529.3	1530.4	1582.8	2092.2	2966.1	"
1945-46							176.3	0.0	0.0	0.0	0.0	820.1	2488.0	"
1946-47							290.2	124.6	88.7	87.5	208.2	1079.8	2557.7	"
1947-48							239.0	52.8	1.8	0.0	58.7	876.1	2441.9	"
1948-49							1937.3	1727.3	1647.6	1631.7	1711.8	2246.8	3230.7	"
1949-50							594.9	369.5	294.4	271.9	360.4	1096.4	2249.1	"
1950-51							586.2	408.5	365.5	360.7	478.2	1215.1	2618.6	"
1951-52							993.3	773.4	704.5	676.2	761.3	1509.3	2769.2	"
1952-53							1274.8	1073.1	1013.4	997.8	1060.7	1663.9	2735.4	"
1953-54							149.5	0.0	0.0	0.0	3.6	792.6	2220.6	"
1954-55							910.1	736.2	693.3	690.5	780.4	1435.9	2419.3	"
1955-56							458.0	266.0	202.9	182.9	275.5	1113.4	2531.3	"
1956-57							626.8	427.6	379.0	371.2	464.2	1199.2	2869.2	"
1957-58							460.3	274.0	232.0	229.6	338.7	1096.4	2626.4	"
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	3610	19000	27000
VARIABLE REFILL CURVES					80	MAF	3000	3000	3000	3000	3000	3000	13000	24000
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	3000	3000	3000	3000	3000	3000	13000	22100
					110	MAF	3000	3000	3000	3000	3000	3000	13000	22100
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)							306.0	71.6	0.0	0.0				

Table 5
Arrow Assured and Variable Refill Curves
Distribution Factors, Forecast Errors, Power Discharge Requirements,
and Operating Rule Curve Lower Limits
2019-20 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	0.0	796.7	878.2	958.9	1127.7	2356.3	3559.9	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							2417.9	2857.9	2743.3	2672.9	2803.6	3408.5	3579.6	3579.6
1929-30							1322.3	1223.4	1266.0	1270.9	1542.8	2797.4	3405.5	"
1930-31							1568.4	1678.4	1584.9	1548.4	1766.3	2652.5	3410.0	"
1931-32							0.0	0.0	0.0	0.0	313.1	1746.0	3031.4	"
1932-33							502.3	412.4	424.5	420.9	637.3	1890.3	2965.9	"
1933-34							0.0	0.0	0.0	0.0	246.0	2356.6	3460.4	"
1934-35							786.2	726.3	834.7	858.9	1047.1	2167.7	3093.7	"
1935-36							880.7	724.2	677.3	645.2	817.2	2191.6	3443.6	"
1936-37							2726.9	3122.4	2997.2	2898.1	3050.0	3579.6	3579.6	"
1937-38							1074.7	1026.9	999.5	1031.9	1259.7	2390.4	3276.9	"
1938-39							1498.2	1454.7	1372.5	1336.1	1631.7	2742.2	3579.6	"
1939-40							1239.1	1143.6	1191.6	1279.0	1559.5	2613.6	3479.8	"
1940-41							2018.0	2362.6	2306.5	2391.8	2832.7	3579.6	3579.6	"
1941-42							1992.9	2338.6	2275.8	2206.7	2413.1	3195.6	"	"
1942-43							2305.4	2730.6	2642.0	2557.6	2856.7	3579.6	"	"
1943-44							3238.6	3579.6	3579.6	3489.8	3579.6	"	"	"
1944-45							2596.6	3091.3	3014.6	2972.4	3098.4	"	"	"
1945-46							302.8	192.8	205.5	184.6	519.7	1870.5	3169.4	"
1946-47							924.0	765.6	768.7	791.1	1046.3	2290.3	3268.5	"
1947-48							703.9	618.8	633.7	575.1	774.4	1985.1	3196.7	"
1948-49							1980.3	2438.2	2371.6	2313.3	2549.7	3425.3	3579.6	"
1949-50							659.5	543.5	559.3	559.9	764.4	1906.5	2842.0	"
1950-51							962.9	880.3	921.3	886.4	1134.0	2259.5	3345.0	"
1951-52							995.9	1122.9	1066.7	986.5	1197.0	2437.6	3464.7	"
1952-53							1374.0	1806.5	1752.9	1695.3	1848.7	2701.6	3411.7	"
1953-54							46.2	0.0	93.1	98.6	388.8	1612.8	2851.1	"
1954-55							738.2	890.6	879.9	827.4	1069.9	2038.7	2821.4	"
1955-56							441.8	338.9	357.3	352.2	588.5	1980.1	3199.2	"
1956-57							510.5	388.8	399.2	382.6	611.9	1837.0	3579.6	"
1957-58							309.4	202.4	258.6	325.7	621.6	1866.6	3249.0	"
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	5000	33200	58700
VARIABLE REFILL CURVES					80	MAF	5000	5000	5000	5000	5000	5000	36000	48000
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	5000	5000	5000	5000	5000	5000	36000	48000
					110	MAF	5000	5000	5000	5000	5000	5000	36000	48000
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)							297.4	63.6	0.0	0.0				

Table 6
Duncan Assured and Variable Refill Curves
Distribution Factors, Forecast Errors, Power Discharge Requirements,
and Operating Rule Curve Lower Limits
2019-20 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	28.9	46.4	57.6	67.8	77.0	91.1	101.9	117.5	274.7	500.6	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							320.3	303.3	311.6	309.5	326.1	432.0	589.6	705.8
1929-30							318.7	301.3	309.4	306.9	331.1	452.2	601.4	"
1930-31							263.1	247.0	258.7	261.3	284.0	402.2	589.6	"
1931-32							0.0	0.0	0.0	0.5	35.8	220.3	499.4	"
1932-33							"	"	"	0.0	0.0	46.3	361.3	"
1933-34							4.7	7.5	31.5	45.7	92.0	299.6	571.9	"
1934-35							53.5	44.2	67.1	68.9	93.1	257.8	494.5	"
1935-36							29.8	14.7	26.3	26.8	54.3	254.5	551.1	"
1936-37							256.0	238.1	248.4	246.3	267.3	387.3	570.9	"
1937-38							48.2	40.0	56.1	64.6	94.8	269.2	528.1	"
1938-39							100.7	90.2	103.0	106.5	138.2	309.4	574.8	"
1939-40							87.6	82.0	102.5	115.5	149.9	312.3	560.9	"
1940-41							171.8	163.4	179.8	194.5	240.0	391.6	584.1	"
1941-42							165.9	159.9	176.1	179.7	209.0	355.1	564.7	"
1942-43							178.1	164.8	179.7	181.7	220.5	376.8	557.3	"
1943-44							326.4	314.0	327.0	326.8	350.4	458.9	620.7	"
1944-45							249.0	236.9	251.0	251.4	269.6	388.0	579.0	"
1945-46							0.0	0.0	0.0	0.0	0.0	161.9	497.1	"
1946-47							"	"	"	"	1.9	205.9	506.8	"
1947-48							11.1	"	17.7	18.3	43.2	223.2	521.7	"
1948-49							237.4	221.1	232.7	231.5	256.8	393.9	623.9	"
1949-50							37.5	21.7	35.9	35.3	61.8	227.0	457.0	"
1950-51							0.0	0.0	0.0	0.0	3.2	191.6	489.2	"
1951-52							68.3	54.6	72.1	72.5	98.4	284.1	540.1	"
1952-53							65.5	54.5	70.0	71.9	94.9	258.7	502.5	"
1953-54							0.0	0.0	0.0	0.0	0.0	121.5	432.0	"
1954-55							1.4	"	5.4	8.3	36.4	203.7	431.8	"
1955-56							0.0	"	0.0	0.0	0.0	172.2	490.0	"
1956-57							21.3	3.6	17.2	19.5	48.7	221.8	558.4	"
1957-58							0.0	0.0	0.0	0.0	0.0	161.8	510.2	"
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	700
VARIABLE REFILL CURVES					80	MAF	100	100	100	100	100	100	1050	2300
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	100	100	100	100	100	100	1050	2300
					110	MAF	100	100	100	100	100	100	1050	2300
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)							66.2	8.5	0.0	0.0				

Table 7
Mica Upper Rule Curves (Flood Risk Management)
End-of-Period Treaty Storage Contents (ksfd)
2019-20 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
Arrow Upper Rule Curves (Flood Risk Management)
End-of-Period Treaty Storage Contents (ksfd)
2019-20 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
Duncan Upper Rule Curves (Flood Risk Management)
End-of-Period Treaty Storage Contents (ksfd)
2019-20 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
Composite Operating Rule Curves for the Whole of Canadian Treaty Storage
End-of-Period Treaty Storage Contents (ksfd)
2019-20 Assured Operating Plan

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.5	7436.3	7231.4	6386.6	5057.6	3006.2	1428.9	1502.3	1615.8	1863.5	4008.4	6676.2	7814.6
1929-30	"	"	"	"	"	"	2246.7	1408.5	1409.8	1508.6	1853.1	"	6505.8	"
1930-31	"	"	"	"	"	"	2676.5	1428.9	1502.3	1615.8	1863.5	"	6526.3	"
1931-32	"	"	"	"	"	"	839.9	342.8	207.5	197.5	667.0	3087.0	6023.0	"
1932-33	"	"	"	"	"	"	951.2	633.5	591.2	575.0	872.9	2830.9	5653.2	"
1933-34	"	"	"	"	"	"	669.6	143.7	31.5	45.7	338.0	3398.0	6546.8	"
1934-35	"	"	"	"	"	"	1515.9	1245.3	1341.3	1372.9	1634.9	3469.5	6005.8	"
1935-36	"	"	"	"	"	"	1397.7	1001.3	921.0	876.4	1174.8	3633.8	6559.9	"
1936-37	"	"	"	"	"	"	3006.2	1428.9	1502.3	1615.8	1863.5	4008.4	6676.2	"
1937-38	"	"	"	"	"	"	1896.4	1383.7	1437.8	1521.0	1816.6	3580.4	6366.2	"
1938-39	"	"	"	"	"	"	2374.1	1428.9	1495.6	1601.4	1863.5	4008.4	6676.2	"
1939-40	"	"	"	"	"	"	1887.4	1282.0	1313.4	1410.3	1721.9	3916.3	6596.1	"
1940-41	"	"	"	"	"	"	2833.6	1428.9	1502.3	1615.8	1863.5	4008.4	6676.2	"
1941-42	"	"	"	"	"	"	2824.0	"	"	"	"	3621.8	6033.5	"
1942-43	"	"	"	"	"	"	2984.3	"	"	"	"	4008.4	6676.2	"
1943-44	"	"	"	"	"	"	3006.2	"	"	"	"	"	"	"
1944-45	"	"	"	"	"	"	"	"	"	"	"	3822.0	"	"
1945-46	"	"	"	"	"	"	675.0	272.9	205.5	184.6	519.7	2852.5	6154.5	"
1946-47	"	"	"	"	"	"	1296.2	898.7	857.4	878.6	1256.4	3496.8	6329.5	"
1947-48	"	"	"	"	"	"	1076.1	698.9	653.2	593.4	876.3	2980.0	6141.9	"
1948-49	"	"	"	"	"	"	3006.2	1428.9	1502.3	1615.8	1863.5	4008.4	6676.2	"
1949-50	"	"	"	"	"	"	1320.6	934.7	889.6	867.1	1186.6	2966.5	5548.1	"
1950-51	"	"	"	"	"	"	1615.3	1237.4	1243.7	1247.1	1609.1	3545.2	6447.2	"
1951-52	"	"	"	"	"	"	2057.5	1398.3	1473.8	1579.6	1844.4	4008.4	6581.0	"
1952-53	"	"	"	"	"	"	2715.0	1398.2	"	"	1811.7	3574.0	6517.9	"
1953-54	"	"	"	"	"	"	669.6	143.7	93.1	98.6	392.4	2526.9	5503.7	"
1954-55	"	"	"	"	"	"	1714.5	1352.2	1413.5	1390.7	1724.6	3207.5	5672.5	"
1955-56	"	"	"	"	"	"	966.0	613.4	560.2	535.1	864.0	3265.7	6220.5	"
1956-57	"	"	"	"	"	"	1203.5	824.9	795.4	773.3	1124.8	3258.0	6676.2	"
1957-58	"	"	"	"	"	"	835.9	484.9	490.6	555.3	960.3	3124.8	6365.3	"

Table 11
Composite End Storage for the Whole of Canadian Treaty Storage
End of Period Treaty Storage Contents (ksfd)
2019-20 Assured Operating Plan

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.5	7436.3	7231.4	6386.6	5057.6	3006.2	1397.2	1299.5	1272.1	1202.5	2699.2	6160.1	7607.0
1929-30	7794.2	7697.1	7028.8	6231.4	4766.4	3390.7	1262.9	342.5	0.4	185.3	816.6	2680.2	5250.2	7201.1
1930-31	7568.6	7598.9	7128.6	6353.3	5106.7	3390.3	1577.8	488.6	0.9	0.8	0.9	1661.4	4081.0	5009.9
1931-32	4791.0	4580.9	3982.6	3304.9	1760.3	221.1	0.9	0.0	4.3	123.7	437.6	2339.5	5778.0	7566.8
1932-33	7705.8	7814.5	7092.2	6636.1	6386.6	5057.6	2955.7	1320.8	591.2	526.5	689.2	2511.8	5653.2	7814.6
1933-34	7779.5	7814.5	7436.3	7231.4	6386.6	5057.6	3031.8	1462.0	771.1	607.4	1206.8	3398.0	6142.4	7605.0
1934-35	7783.3	7706.7	7073.1	6562.4	6386.6	5057.6	2965.6	1479.3	1333.6	1008.8	1150.0	2918.8	6005.8	7814.6
1935-36	7779.5	7787.4	7372.8	6845.6	5607.1	3968.8	1794.0	920.2	829.7	703.4	1174.8	3633.8	6436.1	7676.7
1936-37	7784.0	7692.0	7054.8	6320.2	4832.1	3287.6	1195.9	301.7	0.0	0.0	74.1	1566.7	4325.6	5833.1
1937-38	5847.0	5726.1	5156.1	4714.2	4046.6	3211.6	1896.4	1383.7	999.0	628.1	762.6	2559.2	5725.2	7673.1
1938-39	7644.0	7619.9	7174.4	6838.7	5667.2	4269.3	2405.2	1428.9	1365.3	1472.5	1863.5	3964.8	5815.2	7773.4
1939-40	7785.4	7694.7	7065.8	6655.3	5656.4	4817.9	2703.6	1282.0	1313.4	1410.3	1721.9	3916.3	5760.5	7064.3
1940-41	7158.7	7041.4	6710.7	6733.1	5564.1	4004.0	2171.6	1017.6	1085.3	1379.3	1813.7	2976.4	4575.3	5528.9
1941-42	5361.8	5238.6	5031.1	5660.3	5121.5	4653.4	2829.7	1428.9	1271.7	1082.6	1143.0	2515.7	4867.6	7313.8
1942-43	7727.6	7713.3	7121.6	6542.4	5850.3	5057.6	2984.3	1428.9	1007.3	1081.2	1379.5	2587.3	4840.4	7477.9
1943-44	7779.5	7814.5	7401.2	7186.5	6273.5	5057.6	3006.2	1423.8	1219.8	1261.1	1310.0	2466.3	4430.1	5141.0
1944-45	4998.1	4821.0	4227.4	3854.1	2478.5	833.3	413.3	193.0	0.0	0.0	0.0	1829.4	4796.5	6431.6
1945-46	6325.6	6140.9	5543.9	5047.1	4179.8	3161.2	1082.8	272.9	0.0	0.0	238.0	2569.0	6061.9	7814.6
1946-47	7779.5	7761.9	7436.3	7229.1	6386.6	5057.6	2872.9	1240.7	857.4	878.6	1256.4	3496.8	6329.5	7814.6
1947-48	7779.5	7785.7	7436.3	7231.4	6386.6	5057.6	2899.4	1180.8	653.2	547.2	710.4	2980.0	6141.9	7814.6
1948-49	7779.5	7814.5	7436.3	7231.4	6386.6	5057.6	3006.2	1428.9	1035.3	1037.2	1352.6	3926.0	6094.1	7400.7
1949-50	7708.1	7656.3	7028.6	6619.0	6203.4	5057.6	2871.2	1222.7	851.7	790.5	827.7	2046.6	5389.7	7814.6
1950-51	7779.5	7814.5	7436.3	7231.4	6386.6	5057.6	2953.4	1355.4	942.1	964.9	1113.8	3545.2	6307.6	7814.6
1951-52	7779.5	7814.5	7436.3	7231.4	6386.6	5057.6	2872.3	1398.3	989.8	923.9	1347.7	3763.5	6484.6	7814.6
1952-53	7779.5	7775.2	7274.9	6752.5	5495.9	4056.6	2769.8	1398.2	1010.0	887.4	963.3	2769.5	5721.5	7628.1
1953-54	7779.5	7814.5	7436.3	7231.4	6386.6	5057.6	2931.6	1354.8	677.0	338.2	325.7	2432.3	5503.7	7814.6
1954-55	7791.2	7814.5	7436.3	7231.4	6386.6	5057.6	2979.5	1380.3	1058.1	931.9	854.9	1886.9	5672.5	7814.6
1955-56	7779.5	7814.5	7436.3	7231.4	6386.6	5057.6	2925.1	1216.3	560.2	527.2	864.0	3265.7	6220.5	7814.6
1956-57	7779.5	7814.5	7436.3	7231.4	6386.6	5057.6	2892.6	1254.3	795.4	763.2	903.3	3258.0	6642.2	7814.6
1957-58	7775.8	7706.7	7185.2	6951.5	5956.8	5019.9	2884.6	1298.9	535.0	555.3	697.1	3124.8	6365.3	7814.6
Max	7814.6	7814.5	7436.3	7231.4	6386.6	5057.6	3031.8	1479.3	1365.3	1472.5	1863.5	3964.8	6642.2	7814.6
Median	7779.5	7737.6	7179.8	6795.6	6080.1	5057.6	2872.6	1309.9	854.6	776.9	933.3	2734.4	5769.3	7674.9
Average	7357.3	7323.5	6848.4	6511.7	5586.4	4306.9	2404.8	1110.1	768.6	729.6	940.1	2843.0	5652.6	7317.4
Min	4791.0	4580.9	3982.6	3304.9	1760.3	221.1	0.9	0.0	0.0	0.0	0.0	1566.7	4081.0	5009.9

Table 12
Comparison of Recent Assured Operating Plan Studies

	2011-12 through 2013-14 1/	2014-15	2015-16 through 2016-17 2/	2017-18 through 2018-19 3/	2019-20 through 2023-24 4/
MICA TARGET OPERATION (ksfd or cfs)					
AUG 15	3364.2	3379.2	3379.2	3494.1	3494.1
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	3454.1
OCT	3428.4	3428.4	3404.1	3404.1	3394.1
NOV	21000	22000	21000	19000	16000
DEC	25000	22000	17000	23000	28000
JAN	24000	24000	24000	24000	28000
FEB	21000	21000	26000	23000	24000
MAR	17000	25000	25000	10000	10000
APR 15	20000	17000	21000	15000	10000
APR 30	10000	10000	10000	10000	10000
MAY	8000	8000	8000	8000	8000
JUN	8000	10000	8000	8000	8000
JUL	3467.2	3467.2	3436.2	3436.2	3374.1
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7814.4	7814.6	7814.6	7814.6	7814.5
1928 DEC	5204	5282.1	5092.5	5436.9	5057.6
1929 APR15	1084.4	1078.2	1024.5	1198.5	1272.1
1929 JUL	7329.8	7500.9	7585.9	7649.8	7607.0
COMPOSITE CANADIAN TREATY STORAGE AVERAGE CONTENT (ksfd) 5/					
AUG 31	7362.8	7406.8	7415.3	7385.9	7346.2
DEC	4630.0	4644.6	4490.1	4524.4	4408.8
APR15	908.6	889.3	716.3	811.0	803.2
JUL	7147.1	7279.9	7303.8	7388.7	7359.8
STEP I GAINS AND LOSSES DUE TO REOPERATION					
U.S. Firm Energy (aMW)	0.1	0.0	0.0	-0.5	0.9
U.S. Dependable Peaking Capacity (MW) 6/	-22.9	-3.9	-2.1	6.9 / 35.3	54.0
U.S. Average Annual Usable Secondary Energy (aMW)	21.6	21.3	17.6	22.7	27.9
BCH Firm Energy (aMW)	43.6	44.0	24.0	18.6	26.1
BCH Dependable Peaking Capacity (MW)	41.7	47.8	28.2	37.2	9.3
BCH Average Annual Usable Secondary Energy (aMW)	-13.9	-33.4	-16.2	-24.1	-25.7
COORDINATED HYDRO LOAD (1929) (aMW)					
AUG 15	10969	11187	11367	12028	11927
AUG 31	11104	10971	10944	11399	11560
SEP	11081	9756	9822	10207	9934
OCT	9920	9758	10051	9233	8894
NOV	11458	11821	12152	11434	11525
DEC	13316	13836	13744	13523	13869
JAN	12878	13323	13933	13862	14121
FEB	11721	13179	12876	13006	13069
MAR	10501	12022	11269	11264	10880
APR 15	9786	10476	10894	9583	10984
APR 30	11502	11012	11600	10684	11329
MAY	13287	12198	12166	12344	11079
JUN	13867	12208	11291	11314	12048
JUL	12531	11954	11812	12256	12096
ANNUAL AVERAGE	11856	11819	11794	11689	11695

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

2/ The AOP 2016-17 utilizes the same Step 1 system regulation studies as used in the AOP 2015-16.

3/ The AOP 2018-19 utilizes the same Step 1 system regulation studies as used in the AOP 2017-18.

4/ AOPs 2019-20, 2020-21, 2022-23 and 2023-24 utilize the same Step I system hydro regulation studies as used in the AOP 2021-22.

5/ Prior to AOP15, average content based on 60 years of modified flows. AOP15 through AOP17. averages based on 70 years of modified flows. AOP18 through AOP24 averages based on 80 years of modified flows.

6/ 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 2019-20 AOP/DDPB

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 (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Canadian Projects					
Mica (1; 1890)	Minimum Flow (Qmin)	3000 cfs		All Periods	In place in AOP79, AOP80, AOP84.
Arrow (2; 1831)	Minimum Flow	5000 cfs		All Periods	In place in AOP79, AOP80, AOP84.
	Draft Rate Limit	1.0 ft/day			
Duncan (5; 1681)	Minimum Flow	100 cfs		All Periods	In place in AOP79, AOP80, AOP84.
	Maximum Flow (QMAX)	10000 cfs		All Periods	
	Draft Rate Limit	1.0 ft/day			
	Other			Remove 5-step logic; Operate to meet IJC orders for Corra Linn.	CRTOC agreement to remove 5-step logic procedures to implement 1938 IJC order. 2012
Base System					
Hungry Horse (10; 1530/1531)	Minimum Flow	400 cfs		Minimum project discharge; All Periods	In place in AOP79, AOP80, AOP84.
	Maximum Flow	9500 cfs		Step 1 only; All Periods	
	Minimum Content (SMIN)			None	
	Other			No VECC limit.	VECC limit not in place in AOP79.
Kerr (11; 1510)	Minimum Flow	1500 cfs		All periods	In place in AOP80, AOP84.
	Maximum Flow			None	
	Minimum Content	614.7 ksfd 426.3 ksfd 614.7 ksfd	2893.0 ft 2890.0 ft 2893.0 ft	Aug 15 - Sep May Jun - Jul	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80.
	Maximum Content (SMAX)	58.6 ksfd	2884.0 ft	March (Included to help meet the Apr 15 FERC requirement.)	In place in AOP80, AOP84.
	Other	0.0 ksfd	2883.0 ft	Conditions permitted, should be on or about empty Apr 15.	FERC, AOP80.
Thompson Falls (54; 1490)				None Noted	
Noxon Rapids (38; 1480)	Minimum Content For Step I:	116.3 ksfd 112.3 ksfd 78.7 ksfd 26.5 ksfd 0.0 ksfd 116.3 ksfd	2331.0 ft 2330.0 ft 2321.0 ft 2305.0 ft 2295.0 ft 2331.0 ft	Aug 15 - Aug 31 Sep - Jan Feb Mar Empty Apr 15, Apr 30, and end of CP May - Jul	In place in AOP84, similar operation in AOP80.
	Minimum & Maximum Content For Steps II & III:	116.3 ksfd	2331.0 ft	All periods	In place in AOP79, AOP84.
Cabinet Gorge (56; 1475)				None Noted	

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Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Base System (continued)					
Albeni Falls (16; 1465)	Minimum Flow	4000 cfs		All periods	In place in AOP80, AOP84.
	Minimum Content	(Dec may fill on restriction, note below)			
		582.4 ksfd	2062.5 ft	Aug 15 - Aug 31	In place in AOP80, AOP84.
		465.7 ksfd	2060.0 ft	Sep	
		190.4 ksfd	2054.0 ft	Oct	
		57.6 ksfd	2051.0 ft	Nov - Apr 15	
		0.0 ksfd	2049.7 ft	Empty at end of CP	
		190.4 ksfd	2054.0 ft	Apr 30	
		279.0 ksfd	2056.0 ft	May	
		582.4 ksfd	2062.5 ft	Jun - Jul	
	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).			
		582.4 ksfd	2062.5 ft	Sep	
		465.7 ksfd	2060.0 ft	Oct	
		57.6 ksfd	2051.0 ft	Nov - Mar	
		279.0 ksfd	2056.0 ft	May	
	Kokanee Spawning	1.0 ft		Draft limit below Nov. 20th Elevation through Dec. 31st.	In place before AOP80; supported by minimum contents noted above.
		0.5 ft		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		All periods	
Box Canyon (57; 1460)				None Noted	
Grand Coulee (19; 1280/1281)	Minimum Flow	30000 cfs		All periods	In place in AOP79, AOP80, AOP84.
	Minimum Content	0.0 ksfd	1208.0 ft	Empty at end of CP	
	Step I only:	884.4 ksfd	1240.0 ft	May	Retain as a power operation (for pumping).
	Steps II & III only:	884.4 ksfd	1240.0 ft	May	
		2615.5 ksfd	1288.0 ft	Aug 15 - Nov	
	Maximum Content				
	Step I only:	2615.5 ksfd	1288.0 ft	Sep - Nov (2 ft draft for Op room)	In place in AOP89
		2574.6 ksfd	1287.0 ft	Dec - Feb (3 ft draft for Op room)	Retain as a power operation.
	Draft Rate Limit	1.3 ft/day		Bank sloughage. This Constraint was submitted as 1.5 ft/day; interpreted as 1.3 ft/day mo avg.	
	VECC	884.4 ksfd	1240.0 ft	May	
Chief Joseph (66; 1270)	Other Spill	500 cfs		All periods	
Wells (67; 1220)	Other Spill	1000 cfs		All periods	2/1/05 C. Wagers, Douglas With fish ladder
	Fish Spill			None	
Rocky Reach (68; 1200)	Fish Spill/Bypass			None	
	Other Spill	200 cfs		Aug 31 - Apr 15 (leakage)	

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Project Operating Procedures for the 2019-20 AOP/DDPB

Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Base System (continued)					
Albeni Falls (16; 1465)	Minimum Flow	4000 cfs		All periods	In place in AOP80, AOP84.
	Minimum Content	(Dec may fill on restriction, note below)			
		582.4 ksfd	2062.5 ft	Aug 15 - Aug 31	In place in AOP80, AOP84.
		465.7 ksfd	2060.0 ft	Sep	
		190.4 ksfd	2054.0 ft	Oct	
		57.6 ksfd	2051.0 ft	Nov - Apr 15	
		0.0 ksfd	2049.7 ft	Empty at end of CP	
		190.4 ksfd	2054.0 ft	Apr 30	
		279.0 ksfd	2056.0 ft	May	
		582.4 ksfd	2062.5 ft	Jun - Jul	
	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).			
		582.4 ksfd	2062.5 ft	Sep	
		465.7 ksfd	2060.0 ft	Oct	
		57.6 ksfd	2051.0 ft	Nov - Mar	
		279.0 ksfd	2056.0 ft	May	
	Kokanee Spawning	1.0 ft		Draft limit below Nov. 20th Elevation through Dec. 31st.	In place before AOP80; supported by minimum contents noted above.
		0.5 ft		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		All periods	
Box Canyon (57; 1460)				None Noted	
Grand Coulee (19; 1280/1281)	Minimum Flow	30000 cfs		All periods	In place in AOP79, AOP80, AOP84.
	Minimum Content	0.0 ksfd	1208.0 ft	Empty at end of CP	
	Step I only:	884.4 ksfd	1240.0 ft	May	Retain as a power operation (for pumping).
	Steps II & III only:	884.4 ksfd	1240.0 ft	May	
		2615.5 ksfd	1288.0 ft	Aug 15 - Nov	
	Maximum Content				
	Step I only:	2615.5 ksfd	1288.0 ft	Sep - Nov (2 ft draft for Op room)	In place in AOP89
		2574.6 ksfd	1287.0 ft	Dec - Feb (3 ft draft for Op room)	Retain as a power operation.
	Draft Rate Limit	1.3 ft/day		Bank sloughage. This Constraint was submitted as 1.5 ft/day; interpreted as 1.3 ft/day mo avg.	
	VECC	884.4 ksfd	1240.0 ft	May	
Chief Joseph (66; 1270)	Other Spill	500 cfs		All periods	
Wells (67; 1220)	Other Spill	1000 cfs		All periods	2/1/05 C. Wagers, Douglas With fish ladder
	Fish Spill			None	
Rocky Reach (68; 1200)	Fish Spill/Bypass			None	
	Other Spill	200 cfs		Aug 31 - Apr 15 (leakage)	

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Project Operating Procedures for the 2019-20 AOP/DDPB

Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Base System (continued)					
Rock Island (69; 1170)	Fish Spill/Bypass			None	
Wanapum (70; 1165)	Fish Spill/Bypass			None	
	Other Spill	2200 cfs		All periods	With fish ladder
Priest Rapids (71; 1160)	Minimum Flow			Limit removed	
	Fish Spill/Bypass			None	
	Other Spill	2200 cfs		All periods	With fish ladder
Brownlee (21; 767)	Minimum Flow	0 cfs		All years, all periods in CP & LT studies.	4-04 C. Henriksen
	Downstream Minimum Flow	6500 cfs		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 (72; 765)	Other Spill	100 cfs		All periods	
Ice Harbor (79; 502)	Fish Spill/Bypass			None	
	Other Spill	740 cfs		All periods	
	Incremental Spill			None	
	Minimum Flow			None	
	Other	204.8 ksfd	440.0 ft	All periods	
McNary (80; 488)	Other Spill	3475 cfs		All periods	
	Incremental Spill			None	

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Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Base System (continued)					
John Day (81; 440)	Fish Spill/Bypass			None	
	Other Spill	800 cfs		All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs		Aug 15 - Nov	
		12500 cfs		Dec - Feb	
		50000 cfs		Mar - Jul	
	Other				
	Step I:	269.7 ksfd	268.0 ft	Aug 15	In place AOP80
		242.5 ksfd	267.0 ft	Aug 31 - Sep	
		153.7 ksfd	263.6 ft	Oct - Mar	
		114.9 ksfd	262.0 ft	Apr 15 - May	
		269.7 ksfd	268.0 ft	Jun - Jul	
	Steps II & III:	190.0 ksfd	265.0 ft	Use JDA as run-of-river plant.	
The Dalles (82; 365)	Fish Spill/Bypass			None	
	Other Spill	1300 cfs		All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs		Aug 15 - Nov	
		12500 cfs		Dec - Feb	
		50000 cfs		Mar - Jul	
Bonneville (83; 320)	Fish Spill/Bypass			None	
	Other Spill	8040 cfs		All periods	
	Incremental Spill			None	
Kootenay Lake (Corra Linn (6; 1665))	Minimum Flow	5000 cfs		All periods	BCHydro agreements 1969.
	Other			Remove 5-step logic; Operate to meet IJC orders for Corra Linn.	CRTOC agreement to remove 5-step logic procedures to implement 1938 IJC order. 2012
Chelan (20; 1210/1211)	Minimum Flow	50 cfs		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	308.5 ksfd	1098.0 ft	Aug 15 - Sep	In place in AOP79, AOP80, AOP84
		308.5 ksfd	1098.0 ft	Jul	
				Note: Constraint valid except as needed to empty at end of CP.	
Couer d'Alene L (18; 1341)	Minimum Flow	50 cfs		All periods	In place in AOP79.
	Minimum Content	112.5 ksfd	2128.0 ft	Aug 15 - Aug 31	
		112.5 ksfd	2128.0 ft	May - Jul	
				Flood control may override these minimum contents.	2-1-00 PNCA submittal
Post Falls (18; 1340)	Minimum Flow	50 cfs		All periods	In place in AOP79, AOP80, AOP84.

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Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Other Major Step I Projects					
Libby (3; 1760)	Minimum Flow	4000 cfs		All periods	2-1-97 PNCA submittal
	Other Spill	200 cfs		All periods	2-1-95 PNCA submittal
	Minimum Content	776.9 ksfd	2363.0 ft	1929 Dec	2-1-93 PNCA submittal,
		676.5 ksfd	2355.0 ft	1929 Jan	in place in AOP99.
		603.6 ksfd	2349.0 ft	1929 Feb	
		2147.7 ksfd	2443.0 ft	1929 Jul	
		652.0 ksfd	2353.0 ft	1930 Dec	
		433.2 ksfd	2334.0 ft	1930 Jan	
		389.3 ksfd	2330.0 ft	1930 Feb	
		348.5 ksfd	2326.0 ft	1930 Mar	
		297.4 ksfd	2321.0 ft	1930 Apr 15	
		444.2 ksfd	2335.0 ft	1930 Apr 30	
		499.1 ksfd	2340.0 ft	1930 May	
		1344.6 ksfd	2402.0 ft	1930 Jun	
		1771.9 ksfd	2425.0 ft	1930 Jul	
		317.8 ksfd	2323.0 ft	1931 Dec	
		192.2 ksfd	2310.0 ft	1931 Jan	
		103.1 ksfd	2300.0 ft	1931 Feb - Apr 30	
		192.2 ksfd	2310.0 ft	1931 May	
		676.5 ksfd	2355.0 ft	1931 Jun	
		868.0 ksfd	2370.0 ft	1931 Jul	
		174.4 ksfd	2308.0 ft	1932 Dec	
		103.1 ksfd	2300.0 ft	1932 Jan	
		0.0 ksfd	2287.0 ft	Empty at end of CP	
		373.1 ksfd		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		July 1931 - No more than this amount lower than July 1930.	
		March - Implement PNCA 6(c)2(c).			
	Max Summer Draft	5.0 ft			Hyddef switches A47.1 and A47.2
	Other			Remove 5-step logic; Operate to meet IJC orders for Corra Linn.	CRTOC agreement to remove 5-step logic procedures to implement 1938 IJC order. 2012
Dworshak (31; 535)	Minimum Flow	1600 cfs		All periods	2-1-12 PNCA submittal (1500 cfs pwrhs/100 cfs hatchery water supply)
	Maximum Flow	14000 cfs		All periods (URC may override)	2-1-02 PNCA submittal
		25000 cfs		Up to 25 kcfs for flood control all periods.	
	Start CP at:	652.6 ksfd	1556.8 ft	Aug 15	
	End CP at:	218.4 ksfd	1490.2 ft	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:	652.6 ksfd	1556.8 ft	Aug 15	Target Elev based on 2010
		497.0 ksfd	1535.0 ft	Aug 31	modified flows and new 80 yr
		390.7 ksfd	1519.2 ft	Sep	Flood Control data for Jul-Aug 15
		1016.0 ksfd	1600.0 ft	Jun	and Sep based on use 80-yr
		780.9 ksfd	1573.4 ft	Jul	Median (May 2012)
	Other Spill	100.0 cfs		All periods	

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Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Other Major Step I Projects (continued)					
Lower Granite (76; 520)	Bypass Date			None	
	Other Spill	510 cfs		Aug 15	2-1-09 PNCA submittal
		470 cfs		Aug 31	
		480 cfs		Sep	
		530 cfs		Oct	
		410 cfs		Nov	
		340 cfs		Dec	
		100 cfs		Jan	
		130 cfs		Feb	
		230 cfs		Mar	
		420 cfs		Apr 15	
		440 cfs		Apr 30 - May	
		460 cfs		Jun	
		450 cfs		Jul	
	Incremental Spill			Removed	
	Fish Spill	18000 cfs		Aug 15 - Aug 31	2-1-14 PNCA submittal
		17333 cfs		Apr 15 [= 20 kcfs X (13/15)]	
		20000 cfs		Apr 30 - May	
		18000 cfs		Jun - Jul	
	Maximum Fish Spill	40000 cfs		Aug 15 - Aug 31	2-1-14 PNCA submittal
		34667 cfs		Apr 15 [= 40 kcfs X (13/15)]	
		40000 cfs		Apr 30 - Jul	
	Minimum Flow	11500 cfs		Aug 15 - Nov	2-1-97 PNCA submittal
		11500 cfs		Mar - Jul	
	Other	224.9 ksfd	733.0 ft	Aug 15 - Oct (On MOP Op)	2-1-11 PNCA submittal
		245.7 ksfd	738.0 ft	Nov - Mar (On full pool)	
		224.9 ksfd	733.0 ft	Apr 15 - Jul (On MOP Op)	
Little Goose (77; 518)	Bypass Date			None	
	Other Spill	620 cfs		Aug 15	2-1-09 PNCA submittal
		500 cfs		Aug 31	
		750 cfs		Sep	
		640 cfs		Oct	
		500 cfs		Nov	
		460 cfs		Dec	
		120 cfs		Jan	
		240 cfs		Feb	
		380 cfs		Mar	
		530 cfs		Apr 15	
		580 cfs		Apr 30	
		660 cfs		May	
		590 cfs		Jun - Jul	
	Incremental Spill			Removed	
	Fish Spill (% of outflow)	30%		Aug 15 - Aug 31	2-1-14 PNCA submittal
		26%		Apr 15 [= 30%*(13/15)]	
		30%		Apr 30 - Jul	
	Minimum Fish Spill	8000 cfs		Aug 15 - Aug 31	2-1-14 PNCA submittal
		6933 cfs		Apr 15 [= 8 kcfs X (13/15)]	
		8000 cfs		Apr 30 - Jul	

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Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Other Major Step I Projects (continued)					
Little Goose (continued) **(77; 518)**	Maximum Fish Spill	28000 cfs		Aug 15 - Aug 31	
		26000 cfs		Apr 15 [= 30 kcfs X (13/15)]	
		30000 cfs		Apr 30	
		28000 cfs		May	
		30000 cfs		Jun	
		28000 cfs		Jul	
	Minimum Flow	11500 cfs		Aug 15 - Nov	2-1-97 PNCA submittal
		11500 cfs		Mar - Jul	
	Other	260.4 ksfd	633.0 ft	Aug 15 - Aug 31 (On MOP Op)	2-1-11 PNCA submittal
		285.0 ksfd	638.0 ft	Sep - Mar (On full pool)	MOP value changed in 2011
		260.4 ksfd	633.0 ft	Apr 15 - Jul (On MOP Op)	
Lower Monumental (78; 504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	860 cfs		Aug 15	2-1-09 PNCA submittal
		770 cfs		Aug 31	
		780 cfs		Sep	
		840 cfs		Oct	
		750 cfs		Nov	
		720 cfs		Dec	
		450 cfs		Jan	
		410 cfs		Feb	
		560 cfs		Mar	
		770 cfs		Apr 15	
		780 cfs		Apr 30	
		840 cfs		May	
		780 cfs		Jun	
		790 cfs		Jul	
	Fish Spill	17000 cfs		Aug 15 - Aug 31	2-1-14 PNCA submittal
		22533 cfs		Apr 15 [= 26000 X (13/15)]	
		25000 cfs		Apr 30	
		22000 cfs		May	
		17000 cfs		Jun - Jul	
	Maximum Fish Spill	24000 cfs		Aug 15 - Aug 31	2-1-14 PNCA submittal
		22533 cfs		Apr 15 [= 26000 X (13/15)]	
		25000 cfs		Apr 30	
		22000 cfs		May	
		19000 cfs		Jun	
		24000 cfs		Jul	
	Minimum Flow	11500 cfs		Aug 15 - Nov	2-1-97 PNCA submittal
		11500 cfs		Mar - Jul	
	Other	180.4 ksfd	537.0 ft	Aug 15 - Aug 31 (On MOP Op)	2-1-11 PNCA submittal
		190.0 ksfd	540.0 ft	Sep - Mar (On full pool)	
		180.4 ksfd	537.0 ft	Apr 15 - Jul (On MOP Op)	
Cushman (158; 2206)	Other Spill	240 cfs		All periods	FERC Requirement 03-08
LaGrande (156; 2188)	Other Spill	30 cfs		All periods	4-1-97 PNCA submittal

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Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation	Source
Other Major Step I Projects (continued)					
Lower Baker (154; 2025)	Minimum Flow	1000 cfs		Aug 15 - Sep	2-1-14 PNCA submittal
		1200 cfs		Oct - Jul	
	Maximum Flow	3600 cfs		Aug 15 - Aug 31	2-1-14 PNCA submittal
		3200 cfs		Sep - Oct	
		3600 cfs		Nov - Dec	
		5600 cfs		Jan - Mar	
		3600 cfs		Apr 15 - May	
		5600 cfs		Jun - Jul	
	Max Storage Limits	67.0 ksfd	442.4 ft	All Periods	2-1-13 PNCA submittal
	Min Storage Limit	30.4 ksfd	404.8 ft	Aug 15 - Sep	2-1-13 PNCA submittal
		18.0 ksfd	389.0 ft	Oct - May	
		30.4 ksfd	404.8 ft	Jun - Jul	
Upper Baker (153; 2028)	Max Storage Limits	107.4 ksfd	727.8 ft	Aug 15 - Sep	2-1-13 PNCA submittal
		89.3 ksfd	720.0 ft	Oct	
		77.1 ksfd	714.8 ft	Nov	
		70.8 ksfd	711.6 ft	Dec - Feb	
		81.8 ksfd	716.8 ft	Mar	
		84.6 ksfd	718.0 ft	Apr 15 - Apr 30	
		107.4 ksfd	727.8 ft	May - Jul	
	Min Storage Limits	100.5 ksfd	724.8 ft	Aug 15 - Aug 31	
		93.5 ksfd	721.8 ft	Sep	
		25.5 ksfd	685.0 ft	Oct - Apr 30	
		69.5 ksfd	710.9 ft	May	
		100.5 ksfd	724.8 ft	Jun - Jul	
Timothy (166; 117)	Minimum Flow	10 cfs		All Periods	AOP98 Basetape
	Maximum Flow	535 cfs		All Periods	AOP98 Basetape
	Minimum Content	31.1 ksfd	3190.0 ft	Aug 15 - Aug 31	2-1-01 PNCA submittal
		27.8 ksfd	3185.2 ft	Sep [= (31.1 ksfd + 24.5)/2]	
		24.5 ksfd	3180.0 ft	Oct - May	
		31.1 ksfd	3190.0 ft	Jun - Jul	
		0.0 ksfd	3125.0 ft	Empty by end of CP	
Long Lake (64; 1305)	Minimum Content	50.1 ksfd	1535.0 ft	Aug 15 - Nov	2-1-02 PNCA submittal
		19.7 ksfd	1522.0 ft	Dec - Mar	
		50.1 ksfd	1535.0 ft	Apr 15 - Jul	
	Draft Rate Limit	1.0 ft/day			2-1-03 PNCA submittal
Priest Lake (146; 1470)	Target Contents	35.5 ksfd	3.0 ft	Aug 15 - Sep	
		23.4 ksfd	2.0 ft	Oct	
		0.0 ksfd	0.0 ft	Nov - Apr 30	
		35.5 ksfd	3.0 ft	May - Jul	
	Maximum Content	0.0 ksfd	0.0 ft	Oct	2-1-03 PNCA submittal
	Max/Min Content	35.5 ksfd	3.0 ft	Maintain at or near after runoff through Sep.	

Appendix A
Project Operating Procedures for the 2019-20 AOP/DDPB

Project Name (COE#; BPA&BC#)	Constraint Type	Requirements		Explanation		Source
Other Major Step I Projects (continued)						
Ross (150; 2070)	Maximum Flow	6300 cfs		All Periods		2-1-05 PNCA submittal
	Minimum Contents	521.6 ksfd	1601.0 ft	Aug 15 - Aug 31	Dependent	2-1-12 PNCA submittal
		504.5 ksfd	1598.0 ft	Jun	on Skagit	
		530.5 ksfd	1602.5 ft	Jul	Fisheries	
	Target Contents	0.0 ksfd	1475.0 ft	Empty at end of CP		
		Note: Fixed ARCs and VRCs data from SCL based on 80-yr modified streamflow. (April 2012)				
Gorge (152; 2065)	Maximum Flow	4500 cfs		Aug 31		2-1-13 PNCA submittal
		4000 cfs		Sep - Oct		
		4600 cfs		Nov - Dec		
		5000 cfs		Mar		
		4500 cfs		Apr 15 - Apr 30		
		3500 cfs		May		
	Minimum Flow	2000 cfs		Aug 15 - Aug 31		2-1-13 PNCA submittal
		1500 cfs		Sep - Oct		
		1700 cfs		Nov		
		2000 cfs		Dec		
		2700 cfs		Jan		
		2600 cfs		Feb		
		3000 cfs		Mar		
		2800 cfs		Apr 15 - Apr 30		
		2000 cfs		May		
		2400 cfs		Jun		
		2600 cfs		Jul		
		Note: Additional minimum flows are provided via the Skagit Fisheries Settlement; Monthly minimum flows are provided which vary by water year				

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COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2019-20

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2019-20

January 2016

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) 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 2019-20 (DDPB20).

Information relevant to DDPB20 that is described in AOP20 is referred to and not repeated in this document.

Special terms used in this document, but not defined herein, have the meanings defined in the Treaty, Protocol, or the Entity Agreements referenced in AOP20.

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 Entity agreements referenced in Section 2 of AOP20.

For DDPB20, capacity critical procedures (as described in Subsection 2(b) of the AOP20) were incorporated on a non-prejudicial, non-precedential basis.

The Canadian Entitlement Benefits were computed from the following studies:

Step I -- Operation of the total United States of America (U.S.) Columbia Basin hydro and thermal system, with 15.5 million acre-feet (Maf) of Canadian Treaty Storage operated for optimum power generation subject to flood risk management (FRM) in both countries including coordination with other generation in Canada and the U.S.;

Step II -- Operation of the Step I thermal system, the base hydro system, and 15.5 Maf of Canadian Treaty Storage operated for optimum power generation subject to FRM in both countries;

Step II -- Critical Head Study: Operation of the Step I thermal system, the base hydro system, and 15.5 Maf of Canadian Treaty Storage operated for maximum peaking capability of the U.S. system subject to FRM. This study is used to calculate the Capacity Credit Limit. The procedures for the

Capacity Credit Limit are described in Subsection 2(b) of the AOP20; and

Step III -- Operation of the Step I thermal system and the base hydro system operated for FRM 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 U.S. (Joint Optimum). However, as indicated in Section 4 below, the calculations were not needed for the 2019-20 operating year.

3. Results of Canadian Entitlement Computations

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

Dependable Capacity	= 1141.5 megawatts (MW)
Average Annual Usable Energy	= 454.3 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 U.S. resulted in a 7.1 average annual megawatt (aMW) increase in the Energy Entitlement and increase of 10.0 MW in the Capacity Entitlement (as determined from the Capacity Credit Limit) compared to the Step II study based on optimum power generation only in the U.S. (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 AOP20.

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 AOP20. 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 Thermal Displacement Market (TDM) for the downstream power benefit determination of average annual usable energy. The TDM is 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.

The Entities have agreed to modify the DDPB20 Table 2 calculation of TDM, as was done since DDPB13, to use thermal imports (e.g. market purchases of power from California, but not Canadian Entitlement or Skagit Treaty power) to support exports (not including Canadian Entitlement, plant sales, flow-through-transfers,seasonal exchanges or excess extra-regional thermal installations), on an annual basis, as either flow-through-transfers or seasonal exchanges.

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) January 2015 White Book (WB14) load forecast as described in Subsection 7(a) of the AOP20. 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 included in the Step I load-resource balance as a resource adjustment. The Steps II and III capacity balance also includes the hydro maintenance and the peaking reserves as shown.

The firm energy load carrying capability for the Steps I and III Systems is based on the same critical periods as recent studies. The Step II system critical period started August 16, 1943, one period earlier than the AOP19 Step II study. The firm peak load carrying capability for each system is based on the highest peak load period (January) within the firm energy critical period and the year expected to have the lowest hydro capability for that period. For the AOP/DDPB20, these periods are January 1932, January 1945, and January 1937 for the Steps I, II, and III systems, respectively.

For this AOP, the Step II critical head study results are also shown in Table 4.

Table 5 Computation of Canadian Entitlement

A. Joint Optimum Generation in Canada and the U.S.
B. Optimum Generation in the U.S. Only
C. Optimum Generation in the U.S. with a 0.5 Maf reduction in Total Canadian Treaty Storage.

The essential elements used in the computation of the Canadian Entitlement arising from the downstream power benefits under the Joint Optimum and U.S. Optimum are shown under Columns A and B, respectively. The elements for the computation of maximum allowable reduction in downstream benefits are shown in column C.

Table 5.1 Calculation of the Capacity Credit Limit

This new table shows the information used in calculation of the Capacity Credit Limit, including the January peak hydro capability from the Step II critical head study.

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 U.S. Optimum Step III system regulation studies[1] 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, and 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 2018-19 DDPB and Notable Assumptions

Data from recent DDPBs are summarized in Table 6. As described in Subsection 2(a) of the AOP, the Entities have agreed that the AOP20 – AOP24 studies would be based on the AOP22, including all load and resource assumptions and procedures and hydroregulation studies. As a result, the following explanation of changes and notable assumptions that impact computation of the Entitlement are compared to the 2018-19 DDPB (DDPB19) studies.

a) Steps II and III Hydro Firm Loads

The Steps II and III hydro firm loads shown on Table 3 are noticeably different in the spring and early summer months compared to the DDPB19. For DDPB20, the loads trend higher in April and June and lower March and May compared to the 2018-19 loads.

DDPB20 minus DDPB19 Table 3 Hydro Loads (aMW)

	15-Aug	15-Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	15-Apr	30-Apr	May	June	July	Ann. Avg.	CP Avg
DDPB20 S2	8829	8982	7323	6516	8538	10385	10671	9617	7993	8820	9095	9270	10402	9551	9008	8907
DDPB19 S2	8741	8734	7407	6670	8595	10244	10529	9631	8737	8306	8848	10025	9097	9468	8977	8906
Difference	88	248	-85	-154	-57	141	142	-14	-743	513	248	-754	1305	82	31	0
DDPB20 S3	6487	6621	5147	4426	6195	7821	8078	7149	5729	6660	6934	7176	8135	7132	6693	6966
DDPB19 S3	6353	6346	5199	4546	6219	7636	7891	7123	6434	6104	6641	7883	6782	7001	6621	6978
Difference	134	275	-52	-120	-23	185	187	26	-705	556	293	-707	1354	131	72	-12

The average critical period load factor increased slightly from 75.08% in AOP19 to 76.68% in AOP20.

b) Thermal Installations

The total Step I thermal installation energy capability shown in Tables 1-3 increased by 1338 annual aMW compared to the DDPB19. This is primarily due to the increased thermal needed for peak load/resource balance, and to a much lesser extent, to the increase in PNWA firm load. The additional peak thermal resources resulted in a 1140 annual aMW firm energy surplus which is exported uniformly as shown in Table 1a.

Beginning with AOP/DDPB14 and continuing with this AOP/DDPB, the Entities have agreed to use the average of the two year maintenance schedule for CGS, thereby eliminating the year to year Energy Entitlement variability, and reducing the effect on the AOP storage operations.

The TDM increased by 273 annual aMW due to the increase in PNWA load. Both the thermal installation and TDM changes are shown in the following table.

DDPB20 minus DDPB19 Table 2 Thermal Installations and Thermal Displacement Market (aMW)

	15-Aug	31-Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	15-Apr	30-Apr	May	June	July	Ann. Avg.	CP Avg
DDPB20 TI	11643	11650	11687	11752	11932	12026	11987	11950	11792	10050	9788	9029	9403	11588	11225	11324
DDPB19 TI	10381	10380	10271	10335	10428	10637	10590	10442	9700	9326	8815	7116	9437	10287	9888	9973
Difference	1262	1270	1416	1416	1504	1388	1397	1508	2093	724	973	1913	-35	1301	1338	1351
DDPB20 TDM	10241	10247	10283	10346	10522	10613	10576	10540	10386	8687	8431	7682	8042	10186	9831	9928
DDPB19 TDM	10041	10040	9933	9996	10087	10291	10245	10100	9376	9012	8513	6848	9108	9948	9558	9641
Difference	200	207	350	350	436	323	331	440	1010	-325	-82	834	-1065	237	273	286

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 AOP20), which were updated to 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

The critical rule curves and refill curves were updated in accordance with procedures defined in POP, except for the changes described in Subsection 7(f) of the AOP20. The Mica/Arrow operating criteria for the Step I study is also used in the Step II study.

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

Changes to operating procedures, constraints, and plant data are described in Subsection 7(g) of the AOP20.

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

Because the Entities have agreed that the AOP20 – AOP24 studies would be based on AOP22, the AOP20 uses the same system regulation studies as the AOP22, in which the Entities conducted a full set of Step II (-42, -12, and -22) and Step III (-13) critical period and 30-year system regulation studies for the 2021-22 operating year in accordance with procedures described in Section 3.3 of the POP. In addition the Entities ran a Step II critical head study as described in Subsection 7(g). The system regulation studies used version 29 (.net) of the HYDSIM model. The critical period studies establish the length of the critical stream flow period, the hydro firm load carrying capability, and critical rule curves.

The Step II critical period began in the second half of August rather than September as compared to DDPB19. The Step II critical period comprises 20.5 calendar-months from 16 August 1943 through 30 April 1945. The Step III critical stream flow period is unchanged from the DDPB19 studies. 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 DDPB19, increased by 0.5 aMW, while the average annual firm energy increased by 31.1 aMW. The Step III critical period generation decreased by 11.7 aMW, but the average annual firm energy increased by 72.1 aMW.

The Step II 30-year average generation, compared to DDPB19, increased by 21 aMW, and the Step III 30-year average generation increased by 43 aMW.

g) Step II Critical Head Study

The Step II study was balanced with respect to energy capability, but the peaking capability of the system had a 1582 MW deficit based on January 1945 hydro conditions. Because the Step II system was peak deficit, a critical head study was performed where the peaking capability of the system was maximized and the load reduced until both the peak and energy load could be carried with no peak or energy deficits. The hydro peak capability was maximized by limiting reservoir draft to critical head, the hydraulic head at which the full-gate output of the project's turbines equals the generator-rated capacity, through January, then allowing draft without jeopardizing refill. The January 1945 peaking capability of the Step II base system was 23,249 MW, resulting in a peak capacity surplus of 0 MW.

h) Downstream Power Benefits

The Canadian Capacity Entitlement decreased from 1284.0 MW in the DDPB19 to 1141.5 MW in the DDPB20, a decrease of 142.5 MW. This is the result of application of the Capacity Credit Limit (CCL) in DDPB20. Without application of the CCL the reduction would have been about 20 MW.

The Canadian Energy Entitlement decreased from 472.5 annual aMW in the DDPB19 to 454.3 annual aMW in the DDPB20, a decrease of 18.2 annual aMW. This decrease is primarily the result of an increase in firm energy in Step III.

End Notes

[1] The Step II DDPB22-42 30 year system regulation study dated 18 November 2015 and the Step III DDPB22-13 30-year system regulation study dated 3 December 2015 were used to determine the critical period and 30-year system generation.

Table 1A
Determination of Step I Firm Energy Hydro Loads
(Average MW)
For 2019-20 Assured Operating Plan

		15-Aug	31-Aug	30-Sep	31-Oct	30-Nov	31-Dec	31-Jan	28-Feb	31-Mar	15-Apr	30-Apr	31-May	30-Jun	31-Jul	Ann. Avg.	CP Avg. 1/
1 Pacific Northwest Area (PNWA) Firm Load																	
a) White Book Regional Firm Load 2/	+	24191	24441	22469	21565	24096	26380	26639	25394	23312	22234	22234	21649	23522	25126	23889	23971
b) Exclude 99% of UP&L's Idaho load 3/	-	543	542	483	449	440	475	447	461	435	415	415	463	599	661	489	486
c) Remove WB Coulee Pumping in load	-	201	197	188	83	25	25	23	22	64	234	234	266	247	291	139	129
d) Add BuRec Coulee pumping data 4/	+	201	130	160	69	15	7	3	1	42	212	227	218	200	243	112	103
e) ...Total PNWA Firm Loads	Σ	**23649**	**23833**	**21958**	**21102**	**23646**	**25888**	**26173**	**24912**	**22855**	**21797**	**21812**	**21138**	**22876**	**24418**	**23372**	**23459**
f) Annual Load Shape in Percent	%	101.2%	102.0%	93.9%	90.3%	101.2%	110.8%	112.0%	106.6%	97.8%	93.3%	93.3%	90.4%	97.9%	104.5%	100.0%	100.4%
2 Flows-Out of firm power from PNWA																	
a) White Book Exports 5/	+	965	1260	1178	1247	1043	967	866	853	1158	1344	1170	1153	1463	1292	1134	1121
b) Remove WB Canadian Entitlement	-	429	469	449	449	449	449	449	449	449	449	449	449	449	449	449	450
c) Add estimated CE export 6/	+	431	431	431	431	431	431	431	431	431	431	431	431	431	431	431	431
d) Add export for AOP firm surplus 7/	+	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140
e) Add Seasonal Exchange for WB Balance 8/	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Add Seasonal Exchange for AOP Hydro 8/	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Add imported thermal used out of region 9/	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) *...Subtotal for Table 2*	*Σ*	*2108*	*2362*	*2300*	*2369*	*2165*	*2088*	*1988*	*1974*	*2279*	*2466*	*2291*	*2274*	*2584*	*2414*	*2256*	*2242*
i) Remove Plant Sales	-	536	790	728	797	593	517	416	402	708	894	720	703	1012	842	684	670
j) Remove Flow-through-transfer	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
k) ...Total (Net Exports)	Σ	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**	**1572**
3 Flows-In of firm power to PNWA, except from coordinated thermal installations																	
a) White Book Imports 10/	+	574	574	504	471	640	742	637	620	505	450	450	495	641	689	580	583
b) Remove UP&L imports for 1(b) 3/	-	542	542	483	449	440	475	447	461	435	415	415	463	599	661	489	486
c) Remove Eastern Thermal Installations 11/	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d) Include Seasonal Exchange for WB Balance 8/	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Include Canadian Import for WB deficits 12/	+	0	76	0	0	0	17	356	379	0	0	220	0	0	0	73	80
f) Include California Import for WB deficits 13/	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Include Seas. Exch. Imports for AOP Hydro 8/	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) Remove Flow-Through-Xfers	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
i) ...Total	Σ	**31**	**107**	**21**	**22**	**200**	**284**	**546**	**537**	**69**	**35**	**255**	**32**	**43**	**28**	164	178
4 Total Load		**25189**	**25297**	**23509**	**22652**	**25017**	**27175**	**27198**	**25947**	**24357**	**23334**	**23128**	**22677**	**24406**	**25962**	**24780**	**24853**
5 PNWA Non-Step I Hydro and Non-Thermal Resources																	
a) Hydro Independents (1929)	-	1017	998	982	1054	1056	946	969	798	888	1063	1102	1430	1380	1124	1061	943
b) Non-Step I Coordinated Hydro (1929)	+/-	492	455	549	931	916	939	1240	677	702	808	703	630	1043	658	794	806
c) WB Small Hydro	-	318	316	236	156	125	117	110	116	149	278	280	402	431	413	238	226
d) WB Renewable NUGs	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) WB Renewables	-	956	1451	1299	1402	1052	950	751	721	1300	1583	1254	1344	1797	1434	1225	1201
f) ...Subotal (1929)	Σ	**2784**	**3221**	**3066**	**3543**	**3149**	**2952**	**3071**	**2312**	**3039**	**3732**	**3339**	**3806**	**4651**	**3629**	**3319**	**3176**
6 Step I System Load (1929) 14/	Σ	**22405**	**22076**	**20443**	**19109**	**21869**	**24223**	**24127**	**23635**	**21318**	**19602**	**19789**	**18871**	**19755**	**22333**	**21461**	**21676**
7 Coordinated Thermal Installations 15/																	
a) Columbia Generation Station (WNP2)	+	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	1075	711	538	1023	995	1008
b) Generic Thermal Installations	+	10568	10575	10612	10677	10857	10951	10912	10875	10717	8975	8713	8318	8865	10565	10230	10316
c) ...Total	Σ	**11643**	**11650**	**11687**	**11752**	**11932**	**12026**	**11987**	**11950**	**11792**	**10050**	**9788**	**9029**	**9403**	**11588**	**11225**	**11324**
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/	+	673	678	628	605	673	733	741	707	652	624	624	606	653	694	666	669
9 Step I Hydro Resources (1929) 17/	Σ	**11435**	**11104**	**9385**	**7963**	**10610**	**12930**	**12881**	**12392**	**10178**	**10176**	**10626**	**10448**	**11004**	**11439**	**10902**	**11021**
10 Total Step I System Resources (1929)	Σ	**22405**	**22076**	**20443**	**19109**	**21869**	**24223**	**24127**	**23635**	**21318**	**19602**	**19789**	**18871**	**19755**	**22333**	**21461**	**21676**
11 Coordinated Hydro Load (1929) 18/	Σ	**11927**	**11560**	**9934**	**8894**	**11525**	**13869**	**14121**	**13069**	**10880**	**10984**	**11329**	**11079**	**12048**	**12096**	**11695**	**11827**
a) Coordinated Hydro Load Shape (1929) 19/		102.0%	98.8%	84.9%	76.0%	98.5%	118.6%	120.7%	111.7%	93.0%	93.9%	96.9%	94.7%	103.0%	103.4%	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 2014 White Book (WB14) total regional firm load estimate, which includes estimated Coulee pumping and Idaho loads served by UP&L (now Rocky Mountain Power).
3/ Annex B requires exclusion of Idaho load from area served by UP&L (now Rocky Mountain Power) in 1964.
Imports to serve this load are also excluded, but imports for the 1% within the region are included.
4/ Coulee pumping loads were updated to the PNCA 2/1/2015 data submittal to be consistent with the pumping flows in the Base Flows.
5/ WB14 exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and an estimate of the Canadian Entitlement.
6/ Assumes 446.3 aMW Energy Entitlement exported to Canada, reduced by 3.4% contractual losses to the border.
7/ Added firm export surplus to balance the firm energy loads and resources.
8/ Seasonal Exchanges were not employed in this AOP, but lines 2e), 2f), 3d) and 3g) were retained for continuity.
9/ Added thermal export to balance difference between thermal import and equivalent thermal installation based on generic annual shape.
10/ WB14 Imports include coordinated thermal installations, seasonal & capacity exchanges, flow-through-transfers, and Skagit Treaty power.
11/ Imports identified as coordinated thermal installations are excluded, to be replaced by a portion of the Generic Thermal Installations.
12/ Added Canadian import as a portion of the resources needed to balance WB deficits.
13/ Added California import as a portion of the resources needed to balance WB deficits.
14/ Line 4 minus line 5f), based on 1929 hydro independent capability.
15/ Thermal installations are CGS, plus a generic thermal installation that is sized to meet the Step 1 System peak load.
16/ Transmission losses are 2.60% of all resources including imports.
17/ Step I Hydro (US hydro projects at and upstream of Bonneville Dam) critical period capability shaped to 1929 load, line 6 plus 8a), & 8b), less line 7c).
18/ The Coordinated Hydro Model Load is the Step I Hydro Resources plus Non-Step I Coordinated Hydro, lines 9 + 5b).
19/ The Coordinated Hydro Model 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
(MW)
For 2019-20 Assured Operating Plan

		15-Aug	31-Aug	30-Sep	31-Oct	30-Nov	31-Dec	31-Jan	28-Feb	31-Mar	15-Apr	30-Apr	31-May	30-Jun	31-Jul
1 **Pacific Northwest Area (PNWA) Firm Load**															
a) White Book Regional Firm Load	+	32690	32690	29072	29479	32761	35856	36339	34108	31581	29711	29711	28098	31230	33517
b) Exclude 99% of UPL's Idaho load 1/	-	771	771	638	578	572	654	598	597	574	545	545	587	843	923
c) Adj.for Federal Peak Diversity 2/	-	715	1163	856	922	712	1149	481	651	831	871	1023	917	839	700
d) Remove Whitebook Est Peak Coulee Pumping	-	512	512	449	365	264	337	296	313	402	433	433	474	480	510
e) Add BuRec Coulee Pumping, Feb 1 submittal	+	401	361	352	337	270	395	317	255	340	349	334	380	380	413
f) ....Total PNWA Firm Loads	Σ	**31094**	**30605**	**27481**	**27951**	**31483**	**34110**	**35281**	**32802**	**30115**	**28212**	**28045**	**26500**	**29447**	**31797**
g) Monthly Load Factors	%	76.1%	77.9%	79.9%	75.5%	75.1%	75.9%	74.2%	75.9%	75.9%	77.3%	77.8%	79.8%	77.7%	76.8%
2 **Flows-Out of firm power from PNWA**															
a) White Book Exports	+	1393	1393	1393	1393	1385	1385	1385	1385	1385	1385	1393	1333	1393	1393
b) Remove WB Canadian Entitlement	-	1324	1324	1324	1324	1324	1324	1324	1324	1324	1324	1324	1324	1324	1324
c) Add estimated CE Export capacity	+	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112	1112
d) Add export for WB surplus	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Add WB Seasonal Exchange Export	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Add AOP Seasonal Exchange Export	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Thermal Installations used outside region 3/	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) ...Subtotal	Σ	*1181*	*1181*	*1181*	*1181*	*1173*	*1173*	*1173*	*1173*	*1173*	*1173*	*1181*	*1121*	*1181*	*1181*
i) Remove Plant Sales	-	66	66	66	66	58	58	58	58	58	58	66	8	66	66
j) Remove Flow-through-transfer	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
k) ...Total	Σ	**1115**	**1115**	**1115**	**1115**	**1115**	**1115**	**1115**	**1115**	**1115**	**1115**	**1115**	**1114**	**1115**	**1115**
3 **Flows-In of firm power to PNWA, except from coordinated thermal installations**															
a) White Book Imports	+	925	925	790	731	980	1085	1059	1091	793	697	697	740	998	1078
b) Remove UP&L imports for SW Idaho	-	771	771	638	578	572	654	598	597	574	545	545	587	843	923
c) Remove Eastern Thermal Instal	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d) Add Seasonal Exchange for WB Surplus	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Add Canadian Import for WB deficits	+	0	0	0	0	0	27	631	459	0	0	12	0	0	0
f) Add California Import for WB deficits	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Add Seasonal Exchange for AOP hydro	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) Remove Flow-Through-transfers	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
i) ...subotal to remove from System Load	Σ	**154**	**154**	**153**	**153**	**408**	**457**	**1092**	**952**	**219**	**153**	**165**	**153**	**155**	**156**
4 **PNWA Non-Step I Hydro and Non-thermal Resources**															
a) Hydro Independents (1932)	+	1283	1272	1229	1048	1180	1309	1483	1185	1556	1557	1571	1818	1775	1529
b) Non Step-1 Coordinated Hydro (1932)	+	1490	1563	2210	2089	2101	2077	1987	1849	1770	1813	1966	2004	2351	2424
c) WB Small Hydro	+	376	374	304	220	168	156	152	163	201	318	320	439	452	445
d) WB Renewable NUGs	+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) WB Renewables	+	128	129	129	129	129	129	129	129	128	128	127	128	128	128
f) .... Subtotal (1932) to remove from System Load	Σ	**3277**	**3338**	**3871**	**3485**	**3578**	**3671**	**3750**	**3326**	**3654**	**3816**	**3984**	**4388**	**4706**	**4526**
5 **Step I System Load 4/ (1932)**	Σ	**28778**	**28228**	**24573**	**25429**	**28613**	**31097**	**31555**	**29638**	**27357**	**25359**	**25011**	**23073**	**25702**	**28231**
6 **Coordinated Thermal Installations**															
a) Columbia Generating Station (CGS)	+	1130	1130	1130	1130	1130	1130	1130.0	1130	1130	1130	1130	1130	565	1130
b) Generic Thermal Installations	+	11501	11501	11575	11698	11863	11942	11950	11900	11840	10380	10372	11312	11063	11499
c) ...Total	Σ	**12631**	**12631**	**12705**	**12828**	**12993**	**13072**	**13080**	**13030**	**12970**	**11510**	**11502**	**12442**	**11628**	**12629**
7 **Step I Hydro Resources Needed (1932) 5/**	Σ	**26721**	**26116**	**22326**	**23209**	**26033**	**28108**	**27936**	**25971**	**23854**	**23171**	**22886**	**18772**	**22775**	**26055**
8 **Step I Resource Adjustments**															
a) Hydro Maintenance (1932) 6/	-	5327	5333	5647	5749	5078	4386	3588	3872	4380	4490	4555	3411	3583	5060
b) ...Hydro maint. as % regulated hydro capacity	%	17.9%	17.9%	18.4%	18.8%	16.7%	14.3%	12.0%	13.6%	16.2%	16.0%	16.0%	11.7%	11.6%	15.5%
c) Transmission System Losses (1932) 7/	-	1156	1158	1180	1168	1196	1223	1251	1183	1121	1107	1119	1223	1237	1213
d) Reserves (12.7% of load) 8/	-	4091	4029	3632	3691	4140	4474	4622	4307	3966	3725	3703	3507	3881	4180
e) ....Peak reserves as % load	%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%
f) ....Total Adjustments	Σ	**-10574**	**-10519**	**-10459**	**-10608**	**-10413**	**-10082**	**-9461**	**-9363**	**-9468**	**-9322**	**-9377**	**-8141**	**-8701**	**-10453**
9 **Required Step I Resources**	Σ	**28778**	**28228**	**24573**	**25429**	**28613**	**31097**	**31555**	**29638**	**27357**	**25359**	**25011**	**23073**	**25702**	**28231**
10 **Coordinated Hydro load and Surplus/Deficit (1932)**															
a) Coordinated Hydro Load (1932) 9/	Σ	28211	27680	24536	25297	28134	30185	29923	27821	25624	24983	24852	20776	25127	28479
b) Actual Coord. Hydro Gen (1932) 10/	Σ	29741	29774	30643	30518	30471	30571	29923	28370	27119	28055	28457	29258	30892	31020
c) ...Surplus/Deficit (1932)	Σ	1530	2094	6107	5221	2337	386	0	549	1495	3071	3605	8482	5766	2542

Notes:

1/ Annex B requires exclusion of Idaho load from area served by UP&L (now Rocky Mountain Power) in 1964.
Imports to serve this load are also excluded, but imports for the 1% within the region are included.

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

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

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

5/ Step I hydro resources needed to meet the load = line 5 minus lines 6c and 8f. Actual resource capability is higher.

6/ Maintenance factors based on agreed forecast hydro maintenance rates.

7/ Transmission losses are 3.13% of all resources including imports, net of reserves and maintenance.

8/ Agreed-upon value.

9/ Lines 4b and 7.

10/ System Instantaneous Peak (1932)

Table 2
Determination of Thermal Displacement Market
(Average MW)
For 2019-20 AOP/DDPB Steps II and III Studies

			15-Aug	31-Aug	30-Sep	31-Oct	30-Nov	31-Dec	31-Jan	28-Feb	31-Mar	15-Apr	30-Apr	31-May	30-Jun	31-Jul	Annual Average	CP Avg (42.5 mo)
1	**STEP I THERMAL INSTALLATIONS**																	
a)	From Table 1A, line 7(c)		11643	11650	11687	11752	11932	12026	11987	11950	11792	10050	9788	9029	9403	11588	11225	11324
2	**DISPLACEABLE THERMAL RESOURCES**																	
a)	Minimum Gen. from % of Thermal	-	263	263	264	266	270	273	272	271	267	223	217	207	221	263	255	257
b)	Net Displaceable Thermal Resources	Σ	**11380**	**11387**	**11422**	**11486**	**11662**	**11753**	**11715**	**11679**	**11525**	**9827**	**9571**	**8822**	**9182**	**11325**	**10971**	**11067**
3	**SYSTEM SALES (i.e. Amount of Coordinated Thermal Installation Power Used Outside PNWA)**																	
a)	Flows-Out (Table 1A, line 2(h))	+	2108	2362	2300	2369	2165	2088	1988	1974	2279	2466	2291	2274	2584	2414	2256	2242
b)	...Exclude Exported CE	-	431	431	431	431	431	431	431	431	431	431	431	431	431	431	431	431
c)	...Exclude Plant Sales	-	536	790	728	797	593	517	416	402	708	894	720	703	1012	842	684	670
d)	...Exclude WB Flow-Through-Transfer	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e)	...Exclude WB Seasonal Exchange	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f)	...Exclude SeasEx for WB Surp/Def	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g)	...Exclude SeasEx for AOP Hydro Diff.	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h)	...Exclude Other Flow-ThruTransfer	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
i)	...Exclude Other Seasonal Exchange	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
j)	Total System Sales	Σ	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140
k)	Uniform Average Annual System Sales		1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140	1140
4	**THERMAL DISPLACEMENT MARKET**																	
a)	Line 2b) minus 3k)	Σ	**10241**	**10247**	**10283**	**10346**	**10522**	**10613**	**10576**	**10540**	**10386**	**8687**	**8431**	**7682**	**8042**	**10186**	**9831**	**9928**

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 wind projects with firm sales contracts with California utilities; line 2i), Table 1A.
3d) Flow-through-transfers from the White Book.
3e) Seasonal Exchanges from the White Book.
3f) Seasonal exchange added to White Book value to export WB surplus.
3g) Seasonal Exchanges were not employed in this AOP.
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. Line 3a) less the sum of lines 3b) through 3i).
3k) Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.
4a) 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 2019-20 AOP/DDPB Studies

Period	PACIFIC NORTHWEST AREA LOADS: Area Energy Load 1/ aMW	Annual Energy Load Shape %	Peak Load MW	Load Factor %	THERMAL INSTALLATIONS: Energy Capability 2/ aMW	Annual Energy Shape %	Peak Capability 2/ MW	Capacity Factor %
August 1-15	23649	101.18%	31094	76.06%	11643.4	103.72%	12631	92.18%
August 16-31	23833	101.97%	30605	77.87%	11650.1	103.78%	12631	92.23%
September	21958	93.95%	27481	79.90%	11686.6	104.11%	12705	91.98%
October	21102	90.29%	27951	75.50%	11751.8	104.69%	12828	91.61%
November	23646	101.17%	31483	75.11%	11932.2	106.30%	12993	91.84%
December	25888	110.76%	34110	75.89%	12025.7	107.13%	13072	92.00%
January	26173	111.98%	35281	74.18%	11986.8	106.78%	13080	91.64%
February	24912	106.59%	32802	75.95%	11949.9	106.45%	13030	91.71%
March	22855	97.79%	30115	75.89%	11792.3	105.05%	12970	90.92%
April 1-15	21797	93.26%	28212	77.26%	10050.2	89.53%	11510	87.32%
April 16-30	21812	93.32%	28045	77.78%	9787.6	87.19%	11502	85.09%
May	21138	90.44%	26500	79.76%	9029.0	80.43%	12442	72.57%
June	22876	97.88%	29447	77.69%	9402.6	83.76%	11628	80.86%
July	24418	104.47%	31797	76.79%	11588.2	103.23%	12629	91.76%
Annual Avg. 7/	23372.3	100.00%		76.76%	11225.3	100.00%		88.76%
S1 CP Avg (42.5 mo)	23459.0			**76.68%**	11324.0			
S2 CP Avg (20.5 mo)	23451.0				11395.2			
S3 CP Avg (5.5 mo)	24435.1	AvgAnnEn/MaxPeak		66.25%	11766.7	AvgAnnEn/MaxPeak		85.82%

Period	STEP II SYSTEM: Total Energy Load 3/ aMW	Total Peak Load MW	Hydro Energy Load 4/ aMW	Hydro Peak Load MW	STEP III SYSTEM: Total Energy Load 3/ aMW	Total Peak Load MW	Hydro Energy Load 4/ aMW	Hydro Peak Load MW
August 1-15	20472.8	26918	8829.4	14287	18130.0	23838	6486.6	11207
August 16-31	20632.2	26495	8982.0	13864	18271.1	23463	6621.0	10832
September	19009.3	23791	7322.7	11086	16833.9	21068	5147.4	8363
October	18268.1	24198	6516.3	11369	16177.5	21429	4425.8	8600
November	20470.3	27255	8538.0	14262	18127.7	24136	6195.5	11143
December	22411.2	29529	10385.4	16458	19846.5	26150	7820.8	13078
January	22657.8	30544	10671.0	17464	20065.0	27048	8078.1	13969
February	21566.9	28397	9617.0	15367	19098.9	25147	7149.0	12118
March	19785.5	26071	7993.2	13100	17521.4	23087	5729.1	10117
April 1-15	18869.9	24423	8819.6	12913	16710.5	21628	6660.2	10119
April 16-30	18882.9	24279	9095.2	12777	16722.0	21500	6934.4	9998
May	18299.1	22941	9270.1	10500	16205.0	20316	7176.0	7875
June	19804.4	25493	10401.8	13865	17538.1	22576	8135.4	10947
July	21139.0	27527	9550.8	14898	18720.0	24377	7131.7	11748
Annual Avg. 7/	20233.6		9008.3		17918.2		6692.8	
S2 CP Avg (20.5 mo)	20301.8		8906.6					
S3 CP Avg (5.5 mo)					18733.0		6966.3	
Joint Optimum S2 CP capability 5/ =			**8906.6**		S3 CP capability 6/ =		**6966.3**	

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 1A line 7c), and Table 1B line 6c)).

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 critical water years.

Table 4
Summary of Steps I, II, and III Power Regulations
For 2019-20 Assured Operating Plan

	BASIC DATA		STEP I			STEP II					STEP III			
	# OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	CAPACITY Jan 1932 MW	ENERGY CRITICAL PERIOD Avg.Gen aMW	USABLE STORAGE kaf	CAPACITY Jan 1945 MW	CAPACITY CRITICAL HEAD Jan 1945 MW	ENERGY CRITICAL PERIOD Avg.Gen aMW	ENERGY 30 YEAR ANNUAL Ave. Gen aMW	USABLE STORAGE kaf	CAPACITY Jan 1937 MW	ENERGY CRITICAL PERIOD Avg.Gen aMW	ENERGY 30 YEAR ANNUAL Ave. Gen aMW
1 Hydro Resources														
a) Canadian Storage														
Mica			7000			7000								
Arrow			7100			7100								
Duncan			1400			1400								
Subtotal			15500			15500								
b) Base System														
Hungry Horse	4	428	3072	142	93	3008	155	383	107	100	3008	304	235	98
Kerr	3	160	1219	166	122	1219	175	180	111	129	1219	176	156	125
Thompson Falls	6	85	0	85	56	0	85	85	53	58	0	85	66	58
Noxon Rapids	5	554	231	490	151	0	528	528	131	201	0	528	176	201
Cabinet Gorge	4	239	0	262	104	0	262	262	91	125	0	262	117	126
Albeni Falls	3	50	1155	21	22	1155	18	23	21	21	1155	22	21	20
Box Canyon	4	74	0	71	46	0	70	73	44	48	0	70	57	47
Grand Coulee	24+3SS	6684	5185	5907	2020	5072	6389	6399	1830	2401	5072	5586	1220	2311
Chief Joseph	27	2535	0	2535	1076	0	2535	2535	979	1314	0	2535	706	1238
Wells	10	840	0	840	422	0	840	840	391	492	0	840	286	444
Chelan	2	54	677	59	37	676	60	60	36	45	676	61	57	46
Rocky Reach	11	1267	0	1274	609	0	1274	1274	564	733	0	1274	407	672
Rock Island	18	513	0	529	276	0	529	529	259	323	0	529	190	295
Wanapum	10	986	0	880	503	0	880	880	467	590	0	880	329	523
Priest Rapids	10	912	0	900	489	0	900	900	457	563	0	900	330	499
Brownlee	5	675	975	675	199	974	675	675	257	287	974	675	244	288
Oxbow	4	220	0	220	83	0	220	220	106	116	0	220	105	116
Ice Harbor	6	693	0	693	206	0	693	693	220	297	0	693	162	298
McNary	14	1127	0	1086	615	0	1078	1078	589	752	0	1078	436	696
John Day	16	2484	535	2483	944	0	2483	2483	916	1264	0	2483	686	1221
The Dalles	22+2F	2074	0	2039	768	0	2039	2039	743	1011	0	2039	562	977
Bonneville	18+2F	1088	0	1109	554	0	1109	1109	536	686	0	1109	418	649
Kootenay Lake	0	0	673	0	0	673	0	0	0	0	673	0	0	0
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	0	223	0	0	0
Total Base System 1/		23742	13945	22467	9395	13000	22998	23249	8907	11556	13000	22348	6966	10949
c) Additional Step 1 Projects														
Libby	5	600	4980	373	203									
Boundary	6	1055	0	855	368									
Spokane River Plants 2/	24	173	104	161	98									
Hells Canyon	3	450	0	409	165									
Dworshak	3	450	2015	444	154			NOT APPLICABLE TO STEP II					NOT APPLICABLE TO STEP III	
Lower Granite	6	932	0	932	161									
Little Goose	6	932	0	932	169									
Lower Monumental	6	932	0	928	165									
Pelton, Rereg & RB	7	423	274	434	142									
Total added Step 1		5947	7373	5469	1626									
d) Total Hydro		29689	36818	27936	11021	28500	22998	23249	8907	11556	13000	22348	6966	10949
2 Thermal Installations 3/				13080	11324		13080	13080	11395	11225		13080	11767	11225
3 Resource Adjustments														
a) Hydro maintenance 4/			12.0%	3588	0	14.1%	3237	3273	0	0	14.1%	3146	0	0
b) Peaking reserves 5/			12.7%	4622	n.a.	12.7%	3879	3725	n.a.	n.a.	12.7%	3435	n.a.	n.a.
c) Transmission losses 6/				1251	668		n.a.	n.a.	n.a.	n.a.		n.a.	n.a.	n.a.
4 Total Resources 7/				31555	21676		28961	29331	20302	22781		28847	18733	22174
5 Steps I, II, & III System Loads														
a) PNW Area firm load				35281	23459									
b) Add Net of Exports + Imports				24	1394									
c) Remove Non-Step I resources				1987	806									
d) Remove Hydro Independents				1483	943									
e) Remove Misc. resources				280	1427									
f) Net Step I,II,III System Load 8/				31555	21676		30544	29331	20302	20234		27048	18733	17918
6 SURPLUS (Line 4 - 5f))				0	0		-1582	0	0	2547		1799	0	4256
CRITICAL PERIOD	Starts		August 16, 1928			August 16, 1943					November 1, 1936			
	Ends		February 29, 1932			April 30, 1945					April 15, 1937			
	Length		42.5 Months			20.5 Months					5.5 Months			
	Study ID		22-41			22-42			9/		22-13			

FOOTNOTES FOR TABLE 4

1/ The Table 4 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 agreed to be a different percentage of hydro peaking capability than Step I. Hydro maintenance energy losses are assumed to be 0 in Steps I, II & III

5/ Steps I, II, and III peak reserves are 12.7% of load.

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 are lines 1d) + 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 6, 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/ The Step II Critical Head study is from the 22-12 study.

Table 5
Computation of Canadian Entitlement
For 2019-20 Assured Operating Plan

A. Joint Optimum Power Generation in Canada and the U.S. (From 22-42 and 22-13 studies).
B. Optimum Power Generation in the U.S. Only (From 22-12 and 22-13 studies).
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 22-22 study).

Determination of Dependable Capacity Credited to Canadian Storage (MW)			
	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	8906.6	8904.6	8869.4
Step III - Critical Period Average Generation 2/	6966.3	6966.2	6966.2
Gain Due to Canadian Storage	1940.3	1938.4	1903.2
Average Critical Period Load Factor in percent 3/	76.7%	76.7%	76.7%
Dependable Capacity Gain 4/	2530.4	2527.9	2482.0
Capacity Credit Limit (from CCL Table 5.1) 5/	2283.0	2263.0	2263.0
Canadian Share of Dependable Capacity 6/	**1141.5**	**1131.5**	**1131.5**
Determination of Increase in Average Annual Usable Hydro Energy (aMW)			
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Firm Energy 7/	9008.7	9007.1	8972.0
Thermal Displacement Energy 8/	2415.0	2401.7	2417.4
Remaining Usable Energy 9/	52.7	53.4	57.3
System Average Annual Usable Energy	11476.4	11462.2	11446.6
Step III (without Canadian Storage) 2/			
Firm Energy 7/	6693.1	6693.0	6693.0
Thermal Displacement Energy 8/	3620.6	3620.6	3620.6
Remaining Usable Energy 9/	254.1	254.1	254.1
System Average Annual Usable Energy	10567.8	10567.7	10567.7
Average Annual Usable Energy Gain 10/	908.7	894.5	878.9
Canadian Share of Average Annual Energy Gain 6/	**454.3**	**447.2**	**439.5**

1/ Step II values were obtained from AOP 22-42, 22-12 and 22-22 studies.
2/ Step III values were obtained from AOP 22-13 U.S. Optimum and Joint Optimum studies.
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 5.1, calculated using the 1993 Entitlement Forecast Report methodology.
6/ One-half Dependable Capacity (as limited by the CCL) or Usable Energy Gain.
7/ From 30-year average firm load served, which includes 7 leap years (29 days in Feb.), which is 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 Annual Average Usable Energy.

Table 5.1
Calculation of the Capacity Credit Limit
For 2019-20 Assured Operating Plan

CCL Application All units in MW		Step 2 1/ Jan 1945 (MW)		Step 3 2/ Jan 1937 (MW)
Hydro Peaking Capability		23249		22348
Thermal Peak		13080		13080
Hydro Maintenance	14.08%	-3273		-3146
Reserves on Load	12.70%	-3725		-3638
Total Peaking Capability 3/		29331		28644
Peak Load from Firm Energy Study		30544		27048
Firm Peak Load Carrying Capability (FPLCC) 4/		29331		27048
Capacity Credit Limit (CCL = 29331 - 27048)			2283.0	
Canadian Share			**1141.5**	

Notes:
1/ From 22-12 Critical Head Study
2/ From 22-13 Firm Energy Critical Period Study
3/ Maximum peak load that can be served from the respective system regulation study
4/ FPLCC is the lesser of the Peak Load from the Firm Energy study or
the Peaking Capability of Resources.

Table 6
Comparison of Recent DDPB Studies

	2015-16	2016-17	2017-18	2018-19	2021-22
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	22478.2	22801.8	22775.6	23045.6	23372.3
January Load Factor (%) 1/	112.5	112.6	112.1	112.0	112.0
Critical Period (CP) Avg. Load Factor (%)	73.9	74.0	74.6	75.1	76.7
Annual Firm Exports 2/	832.3	841.9	725.6	795.2	1571.7
Annual Firm Imports 3/	378.6	400.4	233.1	429.3	164.1
Annual Non-Step 1 Hydro & Misc Rsrc 4/	3022.4	3012.8	3130.5	3295.1	3318.5
Total Annual Step 1 Load 5/	19909.5	20230.6	20137.6	20116.4	21461.3
THERMAL INSTALLATIONS (MW) 6/					
January Peak Capability	12146.7	12533.5	12367.5	12596.8	13079.7
CP Energy	9662.4	9995.3	9994.3	9973.2	11324.0
CP Minimum Generation	216.6	224.8	224.8	224.3	256.9
Average Annual System Export Sales	252.6	239.3	195.9	107.5	1139.6
Average Annual Displaceable Market	9111.5	9448.2	9490.6	9557.7	9831.0
Average Annual Energy 7/	9578.8	9910.5	9909.4	9887.7	11225.3
HYDRO RESOURCES (aMW)					
Average Annual Step 1 Hydro Resources 8/	10994.7	10991.3	10890.9	10890.9	10901.8
Average Annual Step 1 Coord Hydro Load 9/	11793.9	11790.9	11689.3	11689.3	11695.4
CRITICAL PERIOD (MONTHS)					
STEP I	42.5	42.5	42.5	42.5	42.5
STEP II	20	20	20	20	20.5
STEP III	5.5	5.5	5.5	5.5	5.5
BASE STREAMFLOWS AT THE DALLES 10/					
Step I 30-yr Avg Streamflow, cfs	175084	175084	173390	173390	173389
Step I CP Average, cfs	114487	114487	112665	112665	112684
Step II CP Average, cfs	101376	101376	99211	99211	130294
Step III CP Average, cfs	56088	56088	54698	54698	54475
CAPACITY BENEFITS (MW)					
Step II CP Generation	8951.5	8948.4	8902.8	8906.1	8906.6
Step III CP Generation	6981.7	6974.5	6957.1	6978.0	6966.3
Step II Gain over Step III	1969.9	1973.9	1945.7	1928.1	1940.3
CANADIAN ENTITLEMENT	1332.3	1333.2	1304.1	1284.0	1141.5
Change due to Mica Reoperation	1.2	0.0	1.3	0.0	10.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm	8960.1	8944.7	8999.4	8977.6	9008.7
Step II Thermal Displacement	2383.9	2422.6	2407.8	2432.6	2415.0
Step II Remaining Usable Secondary	68.1	58.6	51.0	49.9	52.7
Step II System Average Annual Usable	11412.0	11425.8	11458.2	11460.1	11476.4
Step III Annual Firm	6422.8	6354.9	6644.2	6621.0	6693.1
Step III Thermal Displacement	3681.8	3800.3	3598.5	3633.4	3620.6
Step III Remaining Usable Secondary	330.0	309.8	265.4	260.7	254.1
Step III System Average Annual Average	10434.6	10465.1	10508.2	10515.1	10567.8
CANADIAN ENTITLEMENT 11/	488.7	484.0	475.0	472.5	454.3
Change due to Mica Reoperation	3.7	3.7	1.3	1.3	7.1
Step II Peak Capability (MW) (from Energy Study)	28367	30163	29649	28785	28961
Step II Peak Capability (MW) (from Critical Head Study) 12/					29331
Step II Peak Load (MW) (from Energy Study)	27306	29051	29014	28761	30544
Step III Peak Capability (MW) (from Energy Study)	27703	28035	29105	28272	28847
Step III Peak Load (MW) (from Energy Study)	23568	23992	25400	25168	27048

FOOTNOTES FOR TABLE 6

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

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

3. Average annual total firm imports (Table 1A, row 3i).

4. Average annual PNWA Non-Step I Hydro and Non-Thermal Resources (Table 1A, row 5f).

5. Average annual total Step I load (Table 1A, row 6).

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.

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

8. Average annual Step I Hydro Resources (Table 1A, row 9).

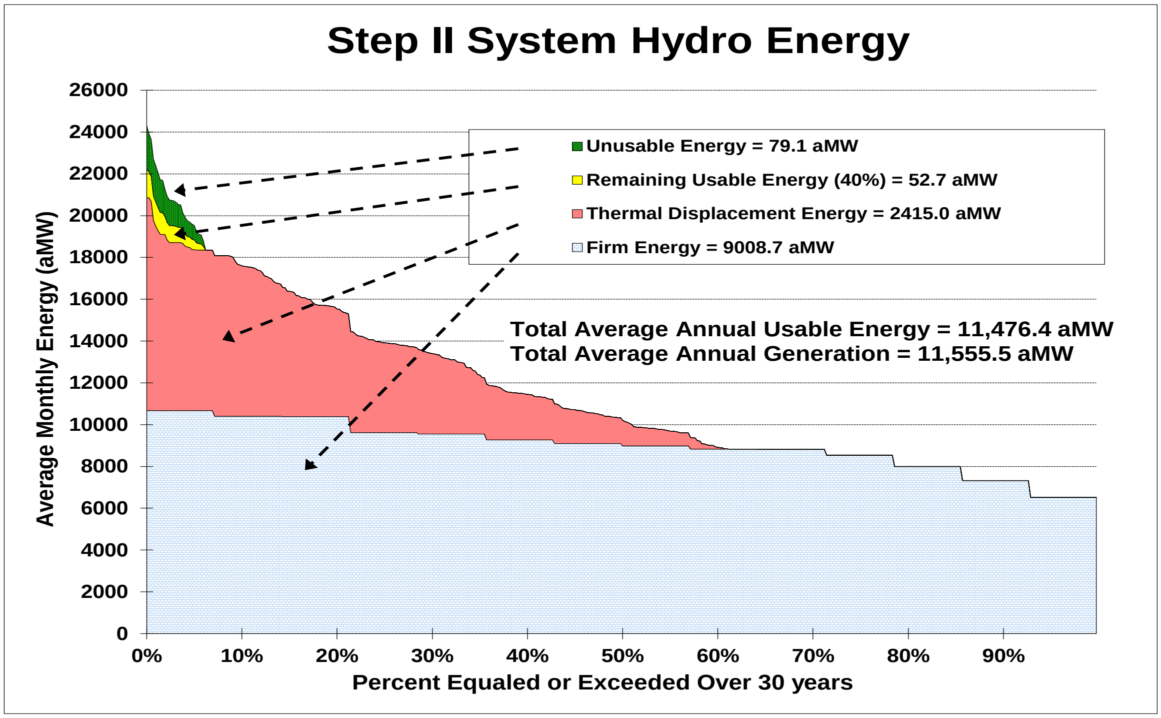
9. Average annual Step I Coordinated Hydro load (Table 1A, row 11).

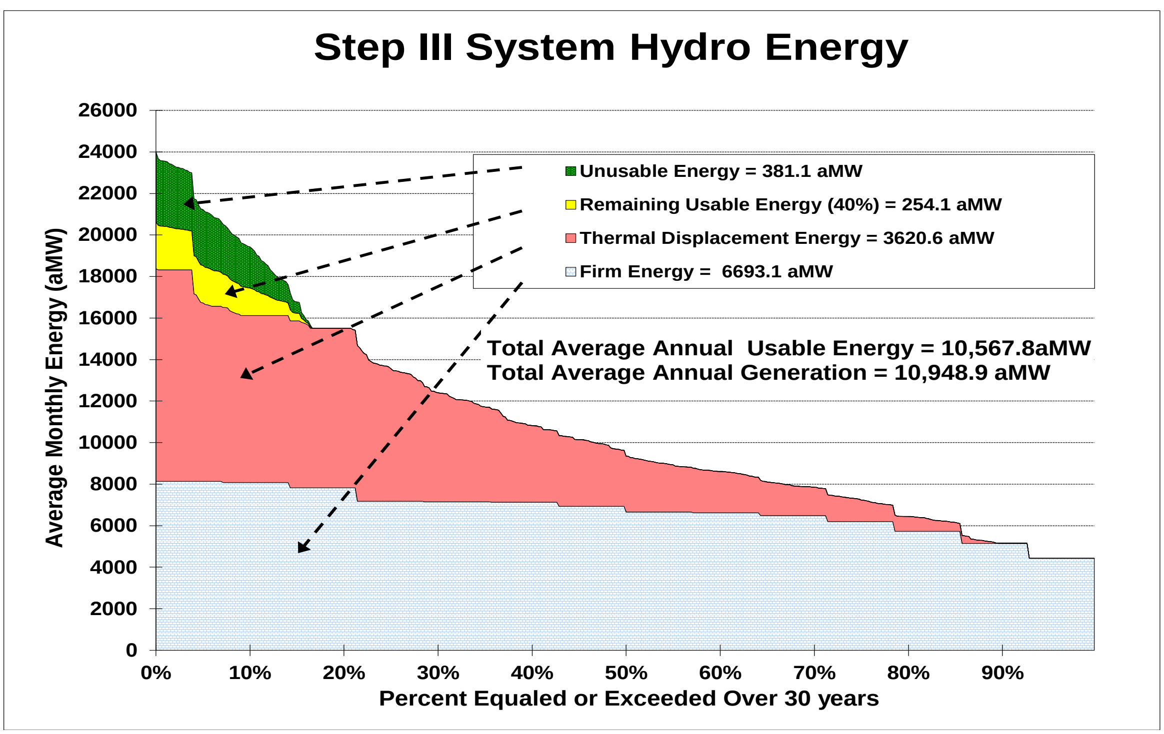
10. The 2010 level modified flows were used beginning with the 2017-18 DDPB with adjustments for the Grand Coulee pumping and return flows. The 2015-16 and 2016-17 DDPBs, based upon 2000 level modified flows, include updated adjustments for the Grand Coulee pumping but not for return flows.

11. The energy benefits for 2015-16, 2017-18 and 2021-22 are all based upon Step II 30-year Joint Optimum 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) to estimate the increase in the energy entitlement that would have resulted 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. The energy benefits for 2019-20, 2020-21, 2022-23 and 2023-24 are based upon the 2021-22 30-Year Joint Optimum hydro regulation studies.

12. The Step II peaking capability is determined from the Step II critical head study. The Firm Peak Load Carrying Capability (FPLCC) is defined to be the minimum of the peak load from the energy study and the peak capability of the resources.

Chart 1
Duration Curves of 30-Year Monthly Hydro Generation
(Average monthly MW)





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