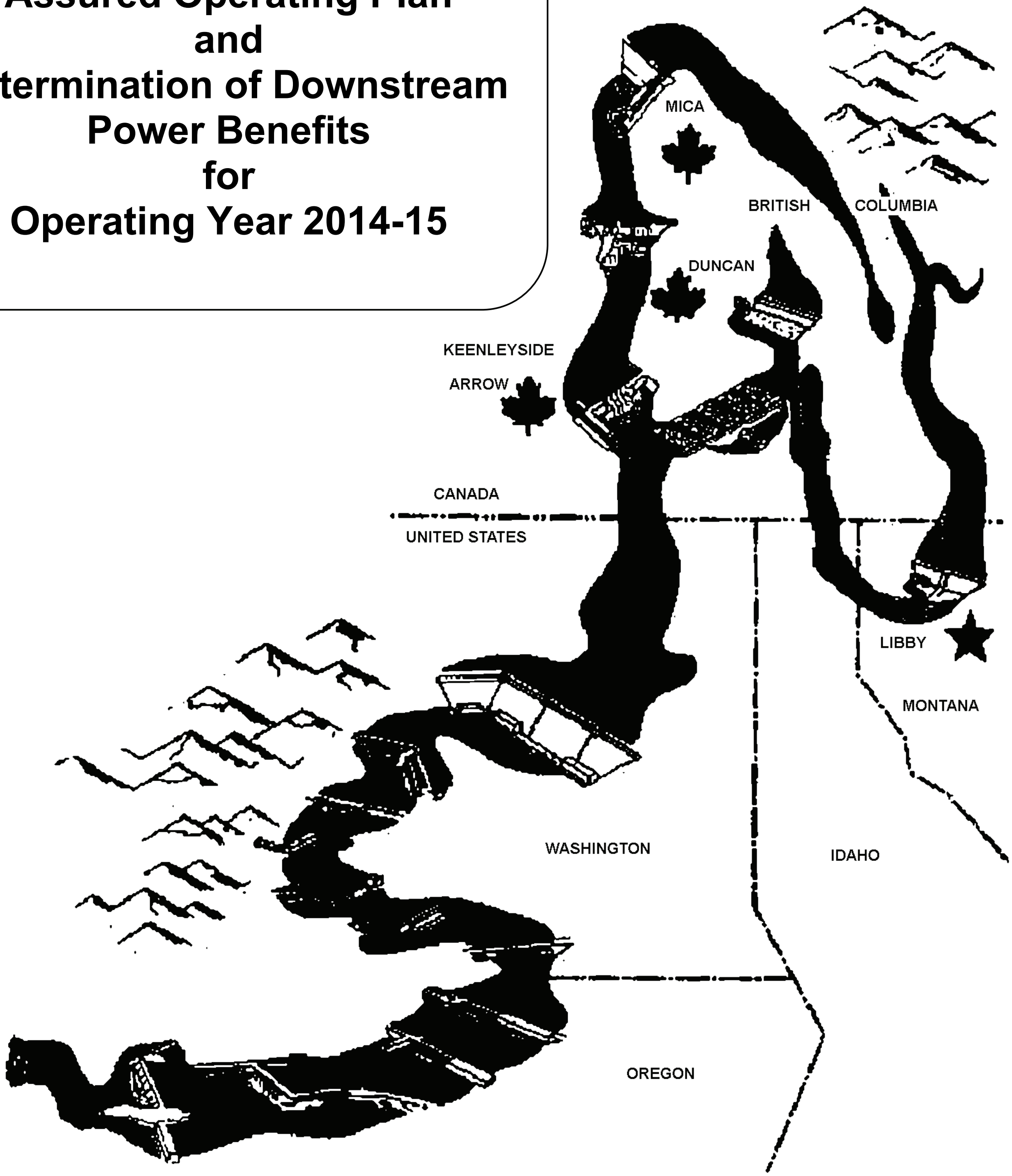
COLUMBIA RIVER TREATY
Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2014-15



Columbia River Treaty Operating Committee
September 2010

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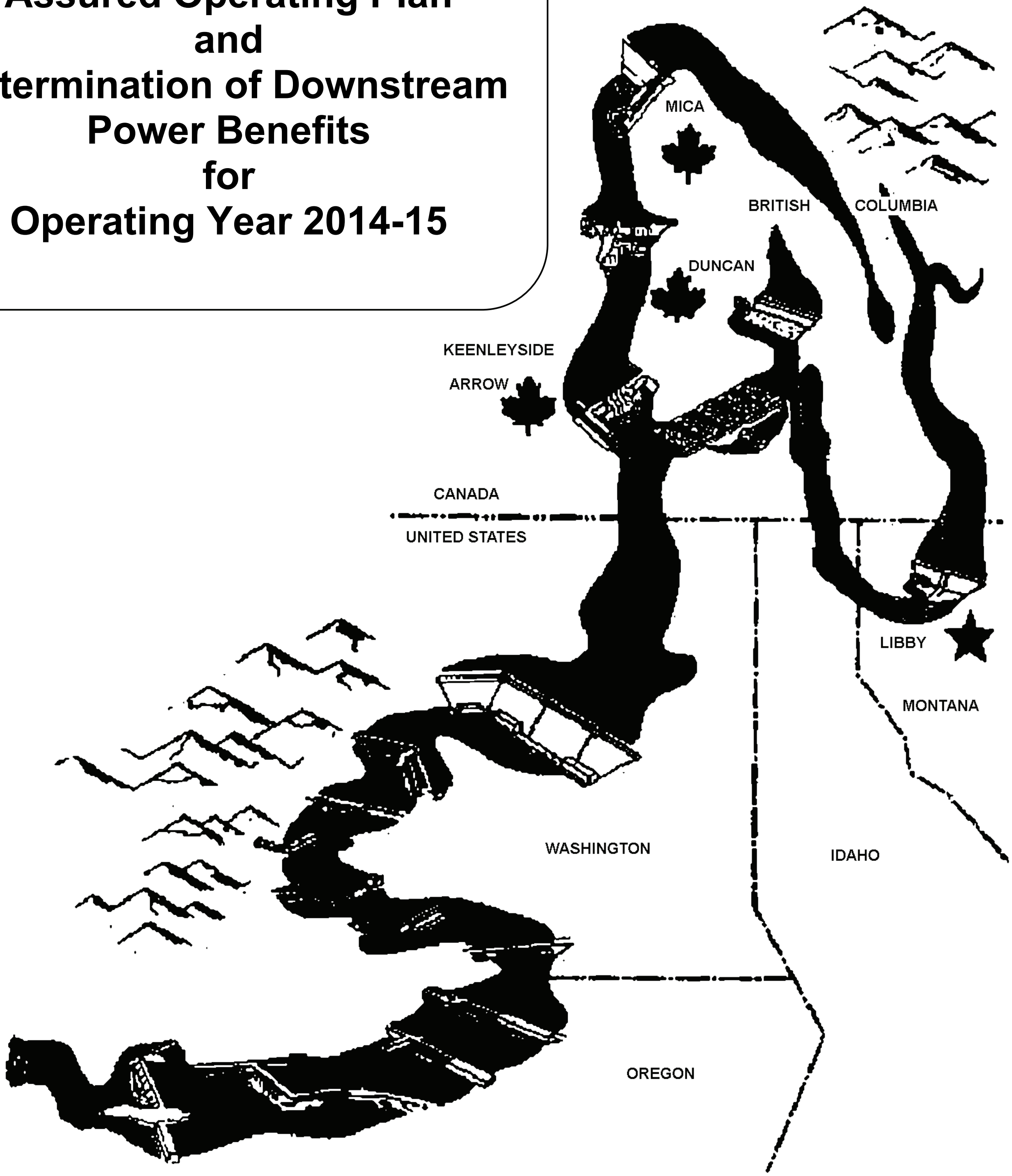
COLUMBIA RIVER TREATY
Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2014-15



Columbia River Treaty Operating Committee

September 2010

COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR OPERATING YEAR 2014-15

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 2014-15" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2014-15," both dated September 2010, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2014-15.

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

Executed for the Canadian Entity this 27th day of September, 2010.

By: ______________________

David G. Cobb
Chair

Executed for the United States Entity this 20th day of September, 2010.

By: ______________________

Stephen J. Wright
Chairman

By: ______________________

Brigadier General John R. McMahon
Member

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COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 2014-15

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TABLE OF CONTENTS

Section **Page**

1. Introduction 1
2. Development of the Assured Operating Plan 1
   a) Procedures 1
   b) System Regulation Studies 3
   c) Evaluation of the Joint Optimum Study 3
      (1) Determination of Optimum Generation in Canada and the USA 3
      (2) Maximum Permitted Reduction in Downstream Power Benefits 4
3. Rule Curves 4
   a) Critical Rule Curves 5
   b) Refill Curves 5
      (1) Assured Refill Curves 5
      (2) Variable Refill Curves 5
   c) Operating Rule Curve Lower Limits (ORCLLs) 6
   d) Upper Rule Curves (Flood Control) 6
   e) Operating Rule Curves 6
4. Operating Rules 7
   a) Operation at or above ORC 7
   b) Operation below ORC 7
   c) Canadian Treaty Project Operating Criteria 7
      (1) Mica Project Operating Criteria 7
      (2) Arrow Project Operating Criteria (APOC) 8
   d) Other Canadian Project Operation 9
5. Preparation of the Detailed Operating Plan 9
6. Canadian Entitlement 10
7. Summary of Changes Compared to the 2013-14 AOP and Notable Assumptions 10
   a) Pacific Northwest Area (PNWA) Firm Load 10
   b) Flows of Power at Points of Interconnection 10
   c) Non-Step I Hydro and Other Non-Thermal Resources 11
   d) Thermal Installations 11
   e) Hydro Project Modified Stream Flows 12
   f) Hydro Project Rule Curves 12
   g) Other Hydro Project Operating Procedures, Constraints, and Plant Data 12

End Notes 13
Table 1 - Mica Project Operating Criteria (English Units) 15
Table 1.1a - Arrow Project Operating Criteria: Definition (English Units) 16
Table 1.1b - Arrow Project Operating Criteria: 30-Year Operating Data (English Units) 17
Table 1.1c - Arrow Project Operating Criteria: Implementation Distribution Factors 18
Table 2 - Comparison of Assured Operating Plan Study Results 19
Table 3 - Critical Rule Curves End of Period Treaty Storage Contents (English Units) 20
Table 4 - Mica Assured and Variable Refill Curves (English Units) 21
Table 5 - Arrow Assured and Variable Refill Curves (English Units) 22
Table 6 - Duncan Assured and Variable Refill Curves (English Units) 23
Table 7 - Mica Upper Rule Curves (Flood Control) (English Units) 24
Table 8 - Arrow Upper Rule Curves (Flood Control) (English Units) 25
Table 9 - Duncan Upper Rule Curves (Flood Control) (English Units) 26
Table 10 - Composite ORCs for the Whole of Canadian Treaty Storage (English Units) 27
Table 11 - Composite Canadian Treaty Storage Operation (English Units) 28
Table 12 - Comparison of Recent Assured Operating Plan Studies (English Units) 29
Table 1M - Mica Project Operating Criteria (Metric Units) 30
Table 1.1aM - Arrow Project Operating Criteria: Definition (Metric Units) 31
Table 1.1bM - Arrow Project Operating Criteria: 30-Year Operating Data (Metric Units) 32
Table 3M - Critical Rule Curves End of Period Treaty Storage Contents (Metric Units) 33
Table 4M - Mica Assured and Variable Refill Curves (Metric Units) 34
Table 5M - Arrow Assured and Variable Refill Curves (Metric Units) 35
Table 6M - Duncan Assured and Variable Refill Curves (Metric Units) 36
Table 7M - Mica Upper Rule Curves (Flood Control) (Metric Units) 37
Table 8M - Arrow Upper Rule Curves (Flood Control) (Metric Units) 38
Table 9M - Duncan Upper Rule Curves (Flood Control) (Metric Units) 39
Table 10M - Composite ORCs for the Whole of Canadian Treaty Storage (Metric Units) 40
Table 11M - Composite Canadian Storage Operation (Metric Units) 41
Table 12M - Comparison of Recent Assured Operating Plan Studies (Metric Units) 42
Appendix A - Project Operating Procedures for the 2014-15 AOP/DDPB 43

HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2014-15

September 2010

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 an Assured Operating Plan (AOP) be agreed to by the Entities created by the Treaty for the operation of the Treaty storage in Canada (Canadian Treaty Storage) during the sixth succeeding year. This AOP for operating year 2014-15 (AOP15) provides the Entities with an operating plan for Canadian Treaty Storage and information for planning the power systems that are dependent on or coordinated with the operation of the Canadian Treaty Storage projects.

2. Development of the Assured Operating Plan

a) Procedures

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

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

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

- Except for the changes noted below, the "Columbia River Treaty Entity Agreement on the Principles and Procedures for Preparing and Implementing Hydroelectric Operating Plans For Operation of Canadian Treaty Storage" (POP), dated October 2003 and signed 16 December 2003, including the 18 November 2003 update to Appendix 1, the November 2004 additions of Appendix 6, Streamline Procedures, and Appendix 7, Table of Median

Stream flows, and the 25 September 2007 addition of Appendix 8 concerning Water Supply Forecasts.

Special terms used in this document, but not defined herein, have the meanings defined in the Treaty, Protocol, or the above Entity Agreements. The POP is based on criteria contained in Annex A and Annex B of the Treaty, the Protocol, and the Columbia River Treaty Flood Control Operating Plan (FCOP), dated May 2003. For this AOP, the Entities have agreed to use only the first of the three streamline procedures defined in Appendix 6 of the POP, which is "Forecasting Loads and Resources" for determining the thermal installations with a modification to allocate available uncommitted Pacific Northwest Area (PNWA) resources and available uncommitted imports from Canada and California, together with a seasonal exchange, to balance the forecasted PNWA firm energy deficit, as described in Subsection 7(b) of this document.

In addition, the Entities have agreed to:

- Include an import from Canada equal to 53% of the estimated Canadian Entitlement, as was done in AOP14;

- Allocate available uncommitted PNWA resources and available imports from California, together with a seasonal exchange, to balance the White Book (WB) firm load/resource deficit, as was done in the AOP14 studies and is described in Subsection 7(b); and

- Adjust thermal installation maintenance schedules as described in Subsection 7(d).

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 (AOP15-41) System Regulation Study. [1]

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

b) System Regulation Studies

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

System regulation studies for the AOP were based on 2014-15 operating year estimated loads and resources in the USA PNWA, including estimated flows of power from and to adjacent areas, and hydro resources in the Columbia River Basin in British Columbia.

In accordance with Protocol VIII, the AOP15 is based on a 30-year stream flow period and the Entities have agreed to use an operating year of 1 August to 31 July. The studies used historical flows for the period August 1928 through July 1958, modified by estimated irrigation depletions for the 2000 level [3] and including updated estimates of Grand Coulee pumping requirements.

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

The flood control operation at Canadian projects was based on individual project flood control criteria instead of a composite curve. The Canadian Entity selected a 5.03/4.44 cubic kilometer (km^3) (4.08/3.6 million acre-feet (Maf)) Mica/Arrow flood control allocation in accordance with Section 6 of the FCOP. Flood Control and Variable Refill Curves are based on historical inflow volumes. Although only 19.12 km^3 (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 25.29 km^3 (20.5 Maf) of usable storage for on-call flood control purposes. Flood Control Rule Curves are implemented in the System Regulation Studies as URCs.

c) Evaluation of the Joint Optimum Study

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

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

To determine whether optimum power generation in both Canada and the

USA was achieved in the system regulation studies, the annual firm energy capability, dependable peaking capability, and average annual usable secondary energy were computed for both the Canadian and USA systems. 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 USA Optimum Study.

In order to measure optimum power generation for the AOP15, 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 USA Optimum Study. The Entities agree that this result is in accordance with Subsection 3.2.A of the POP. The results of these calculations are shown in Table 2.

(2) Maximum Permitted Reduction in Downstream Power Benefits

Annex A, paragraph 7, of the Treaty defines the limits to any reduction in the downstream power benefits in the USA resulting from a change in 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 USA alone; and (ii) Canadian Treaty Storage operation for optimum generation in both Canada and the USA. Using the storage operation for optimum generation in both Canada and the USA, there is a 10.0 aMW increase in the Canadian Entitlement for average annual usable energy and a 1.5 aMW increase in the dependable capacity compared to the operation for optimum generation in the USA alone. (See Table 5 of the DDPB15, columns A and B.)

Since there is no reduction in entitlement, the Entities have determined in Section 4 of the DDPB15 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 2014-15 Operating Year shall be guided by the ORCs and CRCs for the whole of Canadian Treaty Storage, Flood Control 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 hydroregulation 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/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 PDRs are determined in accordance with Section 2.3.B and Appendix 1 of the POP. The 1930-31 inflows are the second lowest January through July unregulated stream flows 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 98.68 km^3 (80 Maf) and 135.69 km^3 (110 Maf), the PDRs were interpolated linearly between the values shown in Tables 4-6. In those years when the January through July runoff volume at The Dalles was less than 98.68 km^3 (80 Maf), or greater than 135.69 km^3 (110 Maf), the PDR values for 98.68 km^3 and 135.69 km^3 (80 Maf and

110 Maf), respectively, were used. For AOP15, as in the AOP12 through AOP14, 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 2014-15, 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 stream flows 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 Control)

The URCs indicate the end-of-period storage content to which each individual Canadian Treaty Storage project shall be evacuated for flood control. The URCs used in the studies were based upon Flood Control Storage Reservation Diagrams contained in the FCOP and analysis of system flood control 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 control space in Mica and Arrow to maximum drafts of 5.03 km^3 and 4.44 km^3 (4.08 Maf and 3.6 Maf) respectively. In actual operation, the URCs will be computed as outlined in the FCOP using the latest forecast of runoff available at that time.

e) Operating Rule Curves

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

During the period 1 August through 31 December, the ORC is defined as the CRC for the first year of the critical period (CRC1) or the ARC, whichever is higher. During the period 1 January through 31 July, the ORC is defined as the higher of the CRC1 and the ARC, unless the VRC (limited by the VRCLL) is lower, then the VRC defines the ORC. During the period 1 January through 15 April, the ORC will not be lower than the ORCLL. The ORC shall be less than or equal to the URC at each individual project. 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 AOP15-41 System Regulation Study will apply to the operation of Canadian Treaty Storage in the 2014-15 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 USA in accordance with Annex A, paragraph 7, of the Treaty, subject to project physical characteristics and operating constraints.

b) Operation below ORC

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

c) Canadian Treaty Project Operating Criteria

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

(1) Mica Project Operating Criteria

In general, the Mica operation in each period is either a target flow or a 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

4(a) or 4(b) above, compensating changes will be made from Arrow to the extent possible.

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

The adoption of the above described procedure for addressing total combined storage draft from Mica and Arrow in this AOP15 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 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 apply from February to June depending on the forecast for The Dalles residual unregulated runoff for the current month through July. The maximum and minimum outflow limits apply under all water conditions, subject to flood control requirements and a maximum combined draft of 17.39 km^3 (14.1 Maf) at Mica + Arrow, respectively. In no circumstance shall the minimum outflow be reduced below the Treaty specified minimum of 142 m^3/s (5,000 cfs).

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

d) Other Canadian Project Operation

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta are included in the AOP15 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. Preparation of the Detailed Operating Plan

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

". . . the powers and the duties of the entities include: . . .

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

The 2014-15 DOP (DOP15) 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 DOP15. Failing agreement on updating the data and/or criteria, the DOP15 for Canadian Treaty Storage shall include the rule curves, Mica and Arrow operating criteria, and other data and criteria provided in this AOP. Actual operation of Canadian Treaty Storage during the 2014 -15 Operating Year shall be guided by the DOP15.

The values used in the AOP studies to define the various rule curves were 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. When refill of Canadian Treaty Storage is being guided by Flood Control Refill Curves, such curves will be computed on a day-by-day basis using the residual volume-of-inflow forecasts depleted by the volume required for minimum outflow, unless higher flows are required to meet firm load, from 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 2014-15."

The Treaty specifies return of the Canadian Entitlement at a point near Oliver, British Columbia, unless otherwise agreed by the Entities. Because no cross border transmission exists near Oliver, the Entities completed an agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024, dated 29 March 1999.[4] This arrangement covers the full 1 August 2014 through 31 July 2015 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 2013-14 AOP and Notable Assumptions

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

a) Pacific Northwest Area (PNWA) Firm Load

Loads for the AOP15 are based on Bonneville Power Administration's (BPA) March 2009 Draft White Book (WB09)[5] expected load forecast. The Draft WB09 forecast for the 2014-15 regional firm load is 23,495 annual aMW, and is based on a 2.0% annual load growth from the 2014 to 2015 operating year. This forecast for the AOP15 is 224 aMW (0.96%) higher than the WB08 forecast used in the AOP14. As there were only minor changes to the Idaho portion of the Utah Power & Light load and to the Coulee pumping requirements, the net PNWA firm load increased by 211 annual aMW (0.93%) from the AOP14 to AOP15.

The average critical period load factor increased from 74.60% in AOP14 (WB08) to 74.76% in AOP15 (WB09). This was mainly due to changes in the 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 AOP15, the estimate of the amount of Canadian Entitlement energy and uncommitted resources that would be assumed to serve load in the PNWA was based on a similar procedure as in the AOP14. This procedure assumes all of the Canadian Entitlement is returned to Canada, but that same power is then available as an uncommitted import for the PNWA. The procedure determines the WB09 firm energy deficit without uncommitted thermal resources, adds a seasonal exchange to dispose of any surplus firm energy and minimize the firm deficits, and then uses a two-step pro rata approach to allocate uncommitted PNWA resources (including unreported combustion turbine (CT) capability) and available uncommitted imports from Canada and California to eliminate deficits. The first step reduces or eliminates the monthly deficits using available uncommitted PNWA resources (without unreported CT capability) and available Canadian imports. For the AOP15, the Entities had agreed that 53% (256 annual aMW) of the estimated Canadian Entitlement (483 annual aMW) would be used as a Canadian import for serving PNWA load, with the uncommitted PNWA resources (without unreported CT capability) being allocated next to reduce or eliminate the monthly deficits. Any remaining deficits are then allocated based on the proportion of available unreported CT capability and assumed available California imports. The resulting amount of allocated imports are included in the Step I load/resource balance. Compared to AOP14, this is equivalent to a 12 annual aMW decrease in Entitlement energy serving load in the U.S.

- The estimated Canadian Entitlement included in export loads was 483 average annual MW of energy and 1333 MW of capacity. The amount computed for the DDPB15 is 479.9 average annual MW of energy and 1368.6 MW of capacity. Iterative studies to update the Canadian Entitlement assumed in the load estimate (see DDPB Table 1) were not performed because the effect on the amount of thermal installations would not significantly affect the results of the studies.
- Compared to the AOP14, power flows-out (exports that are mostly to the southwest but also include the Entitlement) decreased by 772 annual aMW, and power flows-in (imports) decreased by 710 annual aMW. These differences are primarily due to changes in WB imports/exports.
- For the AOP15, a seasonal exchange to reshape the residual hydro load to reflect differences between AOP and Whitebook hydro capabilities was not used.

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 AOP15, these resources have increased by 78 annual aMW over the AOP14. This is primarily due to the addition of wind projects

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 in the 2006-07 and all later AOPs. The procedure includes the Columbia Generating Station (CGS, formerly called Washington Public Power Supply System #2 nuclear power plant) 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 maintenance cycle at CGS was used, which resulted in the same annual average generation from AOP14 to AOP15. The thermal installation maintenance schedules were adjusted and now include a two week maintenance outage for the five combustion turbines that did not have maintenance outages in the AOP14. The total thermal installations increased by 86 annual aMW from AOP14 to AOP15 due to a combination of all changes in loads and resources and maintenance schedules as explained above.

e) Hydro Project Modified Stream flows

The unregulated base stream flows for the Step I System Regulation Studies were the same as the AOP14 studies which were based on the 2000 Level Modified Stream flows and updates to Grand Coulee pumping from the PNCA 2009 Feb. 1 data submittal.

f) Hydro Project Rule Curves

The AOP15 did not utilize the Streamline Procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage"; instead, the full Step I, II and III hydroregulation studies were performed. Some notable assumptions 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 (1225 ft for March-April, 1240 ft for May and 1285 ft for June).

- The agreed allocation of flood control space in Mica and Arrow is 5.03 and 4.44 km^3 (4.08 and 3.6 Maf), respectively.

- The use of the AOP15, 30-year URC data developed by the Corps of Engineers.

- Hedges (also called forecast errors) for Mica, Arrow, Duncan, Libby, and Dworshak were updated from new studies, with large increases at Canadian projects and Dworshak.

- For Step II, the AOP12 Optimizer ARCs were used instead of those developed during the AOP15 process, and combined with adjusted AOP15 VRCs to produce the final PDRs.

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

The AOP15 hydro project operating procedures, constraints and plant data were updated from the PNCA 2009 Feb. 1 data submittal 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 minimum flow requirements are 166 m^3/s (5,850 cfs), in all periods plus the flow needed to reach 368 m^3/s (13,000 cfs) at Lime Point during July through September.

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

- Grand Coulee, which is normally drafted 0.61 m (2 ft) at the beginning of the critical period, is held full through August 31, 1928 to avoid a surplus.

- 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 the 2006 AOP because they are no longer coordinated resources in PNCA Planning. Although included in the Step I hydroregulation model, these projects are now essentially the same as a hydro-independent project.

- Ross and Gorge operating data were updated to the Feb 2009 (2010) PNCA data submittal.

- Hydro-independent projects are not yet updated for the 2000 Modified Flows.

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[1] "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 15-41," dated July 29, 2010.

[2] The conversion factors used are:
(a) million acre-feet (Maf) times 1.2335 equals cubic kilometers (km^3);
(b) thousand second-foot-days (ksfd) times 2.4466 equals cubic hectometers (hm3);
(c) cubic feet per second (cfs) divided by 35.3147 equals cubic meters per second (m^3/s); and
(d) feet (ft) times 0.3048 equals meters (m).

[3] "Report on 2000 Level Modified Streamflow, 1928 to 1999, Columbia River and Costal Basins," prepared by BPA, dated May 2004.

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

[5] March 2009 Draft (study #57) of the "2009 Pacific Northwest Loads & Resources Study, Operating Years 2009 through 2018," dated June 2009 and published November 2009.

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2014-15 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	3,300 - FULL	-	3,379.2	-	34,000	15,000
	1,450 - 3,300	25,000	-	0	-	15,000
	0 - 1,450	32,000	-	0		15,000
August 16-31	3,060 - FULL	-	3,529.2	-	34,000	15,000
	1,300 - 3,060	25,000	-	0	-	15,000
	0 - 1,300	32,000	-	0	-	15,000
September	3,570 - FULL	-	3,529.2	-	34,000	10,000
	3,480 - 3,570	25,000	-	0	-	10,000
	2,140 - 3,480	27,000	-	0	-	10,000
	0 - 2,140	32,000	-	0	-	10,000
October	3,450 - FULL	-	3,428.4	-	34,000	10,000
	2,860 - 3,450	21,000	-	0	-	10,000
	1,360 - 2,860	25,000	-	0	-	10,000
	0 - 1,360	32,000	-	0	-	10,000
November	3,400 - FULL	22,000	-	0	-	10,000
	3,030 - 3,400	19,000	-	0	-	10,000
	1100 - 3,030	25,000	-	0	-	10,000
	0 - 1,100	32,000	-	0	-	10,000
December	3,240 - FULL	22,000	-	204.1	-	10,000
	2,400 - 3,240	25,000	-	204.1	-	10,000
	690 - 2,400	27,000	-	204.1	-	10,000
	0 - 690	32,000	-	204.1	-	10,000
January	2,250 - FULL	24,000	-	204.1	-	12,000
	2,210 - 2,250	26,000	-	204.1	-	12,000
	1,560 - 2,210	28,000	-	204.1	-	12,000
	0 - 1,560	29,000	-	204.1	-	12,000
February	1,370 - FULL	21,000	-	0	-	12,000
	940 - 1,370	26,000	-	0	-	12,000
	850 - 940	22,000	-	0	-	12,000
	0 - 850	26,000	-	0	-	12,000
March	570 - FULL	25,000	-	0	-	12,000
	440 - 570	17,000	-	0	-	12,000
	160 - 440	21,000	-	0	-	12,000
	0 - 160	26,000	-	0	-	12,000
April 1-15	520 - FULL	17,000	-	0	-	12,000
	400 - 520	12,000	-	0	-	12,000
	20 - 400	15,000	-	0	-	12,000
	0 - 20	21,000	-	0	-	12,000
April 16-30	890 - FULL	10,000	-	0	-	10,000
	490 - 890	12,000	-	0	-	10,000
	40 - 490	10,000	-	0	-	10,000
	0 - 40	15,000	-	0	-	10,000
May	160 - FULL	8,000	-	0	-	8,000
	20 - 160	10,000	-	0	-	8,000
	0 - 20	12,000		0	-	8,000
June	2,140 - FULL	10,000	-	0	-	8,000
	1,450 - 2,140	8,000	-	0	-	8,000
	1,140 - 1,450	10,000		0	-	8,000
	0 - 1,140	16,000	-	0	-	8,000
July	3,110 - FULL	-	3,467.2	-	34,000	10,000
	2,880 - 3,110	-	3,405.2	-	34,000	10,000
	1,650 - 2,880	22,000	-	0	-	10,000
	0 - 1,650	24,000	-	0	-	10,000

Notes:

1/ If the Mica target end-of-month storage content is less than 3529.2 ksfd, then a maximum outflow of 34000 cfs will apply.

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

TABLE 1.1a
(English Units)
ARROW PROJECT OPERATING CRITERIA
DEFINITION
2014-15 ASSURED OPERATING PLAN

Period	Vol Runoff Period	The Dalles Vol Runoff (Maf)	Max Storage Limit (ksfd)	Max Outflow Limit (cfs)	Min Outflow Limit (cfs)
15 Aug - 31-Dec	-		URC	-	10,000
31-Jan	-		URC	70,000	10,000
29 Feb	1 Feb - 31 Jul	≤ 70	URC	60,000	20,000
		>70 to <80	URC to 1800		
		≥ 80	1800		
31-Mar	1 Mar - 31 Jul	≤ 65	URC	-	20,000
		>65 to <75	URC to 900		
		≥ 75	900		
15-Apr	1 Apr - 31 Jul	≤ 61	URC	-	15,000
		>61 to <70	URC to 900		
		≥ 70	900		
30-Apr	1 Apr - 31 Jul	≤ 61	URC	-	12,000
		>61 to <70	URC to 1000		
		≥ 70	1000		
31-May	1 May - 31 Jul	≤ 68	URC	-	10,000
		>68 to <70	URC to 2200		
		≥ 70	2200		
30-Jun	1 Jun - 31 Jul	≤ 33	URC	-	5,000
		>33 to <35	URC to 3300		
		≥ 35	3300		
31-Jul	-		URC	-	10,000

Notes:
1/ If the Maximum Storage Limit is computed to be above the URC, then the URC will apply.
2/ Interpolate when there are two values. For example, if the February-July volume runoff is between 70 Maf and 80 Maf, then the Maximum Storage Limit is interpolated between February's URC and 1800 ksfd.
3/ The Maximum Average Monthly Outflow Limit takes precedence over the Maximum Storage Limit. However, the Maximum Outflow Limit may be exceeded to avoid storage above the URC.
4/ The Minimum Average Monthly Outflow Limit is an operating limit and may be reduced to as low as 5,000 cfs (Treaty minimum) to avoid drafting Mica+Arrow storage beyond 14.1 Maf.

TABLE 1.1b
(English Units)
ARROW PROJECT OPERATING CRITERIA
30 YEAR OPERATING DATA
FOR 2014-15 ASSURED OPERATING PLAN

	AUG15-DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
Maximum Average Monthly Flow Limits (cfs)									
	-	70,000	60,000	-	-	-	-	-	-
Minimum Average Monthly Flow Limits (cfs)									
	10,000	10,000	20,000	20,000	15,000	12,000	10,000	5,000	10,000
End-of-Period Maximum Storage Limits (ksfd)									
1928-29	-	-	URC	URC	URC	URC	URC	URC	-
1929-30	-	-	URC	URC	URC	URC	URC	URC	-
1930-31	-	-	URC	URC	URC	URC	URC	URC	-
1931-32	-	-	1800.0	900.0	900.0	1000.0	2200.0	3300.0	-
1932-33	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1933-34	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1934-35	-	-	1800.0	900.0	900.0	1000.0	URC	3300.0	-
1935-36	-	-	1825.0	900.0	900.0	1000.0	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	3548.8	-
1937-38	-	-	1800.0	900.0	900.0	1000.0	URC	3300.0	-
1938-39	-	-	1947.9	960.4	1525.2	1574.3	URC	URC	-
1939-40	-	-	2203.3	1562.3	2333.2	2345.9	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1942-43	-	-	1800.0	900.0	900.0	1000.0	2200.0	3300.0	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	1940.5	1116.9	1303.6	1370.2	URC	3300.0	-
1945-46	-	-	1800.0	900.0	900.0	1000.0	URC	3300.0	-
1946-47	-	-	1800.0	900.0	900.0	1000.0	2200.0	3300.0	-
1947-48	-	-	1800.0	900.0	900.0	1000.0	URC	3300.0	-
1948-49	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1949-50	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1950-51	-	-	1800.0	900.0	900.0	1000.0	URC	3300.0	-
1951-52	-	-	1800.0	900.0	900.0	1000.0	2200.0	3300.0	-
1952-53	-	-	1800.0	900.0	900.0	1000.0	URC	3300.0	-
1953-54	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1954-55	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1955-56	-	-	1800.0	900.0	900.0	1000.0	2200.0	3300.0	-
1956-57	-	-	1800.0	900.0	900.0	1000.0	2200.0	3300.0	-
1957-58	-	-	1800.0	900.0	900.0	1000.0	2200.0	3300.0	-

TABLE 1.1c
APOC IMPLEMENTATION
DISTRIBUTION FACTORS FOR THE DALLES
2014-15 ASSURED OPERATING PLAN

Forecast Date	Forecast Period	The Dalles Distribution Factors 1/ Jan-Jul	Feb-Jul	Mar-Jul	Apr-Jul	May-Jul	Jun-Jul
1-Jan	1 Jan - 31 Jul	1.0000	0.9392	0.8589	0.7735	0.7174	0.4393
1-Feb	1 Feb - 31 Jul		1.0000	0.9145	0.8235	0.7638	0.4677
1-Mar	1 Mar - 31 Jul			1.0000	0.9005	0.8352	0.5114
1-Apr	1 Apr - 31 Jul				1.0000	0.9275	0.5679
1-May	1 May - 31 Jul					1.0000	0.6123
1-Jun	1 Jun - 31 Jul						1.0000

Notes:
1/ Unless otherwise agreed, the DOP15 will apply these distribution factors to the monthly volume forecast at The Dalles for computing the Month-July runoff volumes required by the APOC. These distribution factors are calculated from the median 71 year Jan-Jul, Feb-Jul, etc., volumes.

For Example, in the month of May:

	From Table 1.1c			Look up Table 1.1a			
1 May Forecast Forecast Volume = 65 Maf (May-Jul)	The Dalles Distribution Factor	Month-Jul Volume Runoff (Maf)	Month-Jul Volume Runoff (km^3)	The Dalles Volume Runoff (Maf)	The Dalles Volume Runoff (km^3)	Maximum Storage Limit (ksfd)	Maximum Storage Limit (hm^3)
May	1.0000	65.0	80.2	$\leq$ 68	$\leq$ 83.9	URC	URC
June	0.6123	39.8	49.1	$\geq$ 35	$\geq$ 43.2	3300	8073.8

TABLE 2
COMPARISON OF 2014-15 ASSURED OPERATING PLAN
STUDY RESULTS

Study 15-41 provides Optimum Generation in Canada and in the United States.
Study 15-11 provides Optimum Generation in the United States only.

	Study No. 15-41	Study No. 15-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	11939.4	11939.4	0.0		
Canada 2/, 3/	2956.1	2912.2	44.0		
Total	14895.5	14851.6	43.9	3	131.7
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	29585.0	29594.0	-9.0		
Canada 2/, 5/	5814.4	5766.6	47.8		
Total	35399.4	35360.6	38.8	1	38.8
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3223.8	3202.5	21.3		
Canada 2/, 7/	279.1	312.5	-33.4		
Total	3502.9	3515.0	-12.1	2	-24.1
			Net Change in Value =		146.4

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

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

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

4/ U.S. system dependable peaking capability was determined from January 1932.

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

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

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

TABLE 3
(English Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2014 - 15 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	3492.1	3352.4	2997.2	2488.7	1591.1	768.9	471.2	458.9	469.8	930.7	2576.4	3406.7
1929-30	3512.5	3513.9	3250.1	2824.3	2192.0	1557.8	553.9	69.6	0.0	0.0	220.2	870.1	2069.1	3138.9
1930-31	3360.4	3407.3	3249.8	2824.3	2189.8	1423.1	550.7	35.7	0.0	0.0	0.0	571.4	1764.8	2334.8
1931-32	2365.5	2344.7	2080.3	1596.5	1040.5	236.8	79.7	0.0						
							ARROW							
1928-29	3579.6	3579.6	3539.8	3355.7	3019.2	2407.6	1583.3	872.5	621.0	525.3	554.3	1316.1	2854.4	3454.5
1929-30	3561.8	3563.2	3295.6	2844.3	2207.3	1506.4	571.6	237.3	0.0	9.1	317.4	1259.6	2266.4	3183.1
1930-31	3407.9	3455.4	3295.9	2845.2	2206.0	1376.8	713.1	208.0	0.0	0.0	0.0	612.3	1535.8	1730.5
1931-32	1764.2	1854.8	2009.9	1590.4	1020.5	357.1	124.8	0.0						
							DUNCAN							
1928-29	705.8	705.8	631.7	631.3	595.0	385.8	264.9	79.4	88.5	94.0	105.3	222.8	497.6	639.7
1929-30	697.0	704.7	705.8	705.8	624.7	371.4	148.8	7.0	0.0	0.0	33.1	148.1	367.7	585.3
1930-31	651.8	704.9	705.8	705.1	627.4	382.2	169.5	23.2	0.0	0.0	2.0	159.2	397.1	314.1
1931-32	238.8	131.8	100.8	92.1	50.0	0.0	0.0	0.0						
							COMPOSITE							
1928-29	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3439.3	1720.8	1180.7	1078.2	1129.4	2469.6	5928.4	7500.9
1929-30	7771.3	7781.8	7251.5	6374.4	5024.0	3435.6	1274.3	313.9	0.0	9.1	570.7	2277.8	4703.2	6907.3
1930-31	7420.1	7567.6	7251.5	6374.6	5023.2	3182.1	1433.3	266.9	0.0	0.0	2.0	1342.9	3697.7	4379.4
1931-32	4368.5	4331.3	4191.0	3279.0	2111.0	593.9	204.5	0.0						

Note: These rule curves are input to the AOP 2015 Step 1 study.
They will be adjusted to eliminate any Canadian composite crossovers according to 3 a) of the AOP document.

TABLE 4
(English Units)
MICA
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2014 - 15 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	403.7	582.3	647.6	664.0	658.9	647.4	654.2	679.1	742.4	1504.6	3103.6	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2208.0	2023.6	1966.3	1962.1	2002.4	2520.1	3074.8	3529.2
1929-30							1184.6	958.8	893.0	908.1	1063.8	1917.0	2784.7	"
1930-31							1442.7	1226.4	1155.8	1148.9	1238.4	1935.9	2861.1	"
1931-32							995.3	785.3	721.8	716.2	832.7	1643.2	2738.8	"
1932-33							901.8	727.1	681.0	673.3	750.0	1542.6	2572.6	"
1933-34							83.6	0.0	0.0	0.0	43.8	1289.9	2829.8	"
1934-35							1170.6	977.7	943.6	955.6	1024.9	1746.6	2652.3	"
1935-36							951.3	758.4	713.1	705.0	799.2	1691.6	2917.2	"
1936-37							2194.7	1989.6	1917.6	1902.5	1990.9	2532.2	3107.1	"
1937-38							1274.5	1081.9	1018.1	1016.6	1108.9	1866.3	2832.7	"
1938-39							1247.3	1099.1	1042.6	1061.6	1172.0	1958.9	3098.4	"
1939-40							1028.3	843.0	804.1	817.3	946.1	1756.3	2853.5	"
1940-41							1627.9	1432.7	1381.3	1393.6	1569.9	2312.3	3088.9	"
1941-42							1671.5	1480.2	1420.6	1409.5	1484.9	2162.5	2988.4	"
1942-43							1912.1	1698.5	1635.7	1624.2	1776.0	2490.6	3076.1	"
1943-44							2300.4	2079.8	2021.3	2015.2	2083.2	2641.3	3249.8	"
1944-45							2227.7	2044.0	1999.4	2004.0	2053.0	2568.0	3167.2	"
1945-46							695.3	471.1	406.2	388.5	479.2	1342.9	2734.7	"
1946-47							809.2	639.0	602.8	606.6	722.5	1602.3	2804.4	"
1947-48							758.0	567.1	515.8	493.5	572.9	1398.8	2688.6	"
1948-49							2456.3	2243.3	2163.3	2150.8	2227.7	2767.8	3477.3	"
1949-50							1113.8	884.1	808.8	790.9	874.9	1618.9	2495.7	"
1950-51							1105.1	923.1	879.8	879.7	992.8	1737.4	2865.2	"
1951-52							1512.2	1288.4	1219.2	1195.2	1276.2	2031.3	3015.8	"
1952-53							1793.8	1588.4	1528.5	1516.9	1575.9	2185.7	2982.0	"
1953-54							668.4	473.0	438.9	434.7	517.7	1315.4	2467.2	"
1954-55							1429.0	1251.1	1208.0	1209.5	1295.3	1957.9	2665.9	"
1955-56							976.9	780.5	717.1	701.9	789.8	1635.9	2777.9	"
1956-57							1145.7	942.3	893.4	890.2	978.8	1721.6	3115.8	"
1957-58							979.2	788.5	746.2	748.6	853.2	1618.9	2873.1	"
DISTRIBUTION FACTORS							0.9760	0.9800	0.9760	0.9820	0.9660	0.7910	0.5060	N/A
FORECAST ERRORS (KSFD)							728.0	522.0	455.0	420.0	420.0	401.0	397.0	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3478	6834	42766
VARIABLE REFILL CURVES					80	MAF	3000	3000	3000	3000	3000	3000	22000	30000
(BY VOLUME RUNOFF AT THE DALLE					95	MAF	3000	3000	3000	3000	3000	3000	22000	30000
					110	MAF	3000	3000	3000	3000	3000	3000	22000	30000
VARIABLE REFILL CURVE LOWER LIMIT					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)							413.9	22.4	0.0	0.0				

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2014 - 15 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	538.0	741.0	821.7	955.7	2177.2	3320.5	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							2473.0	2946.1	2953.2	2883.5	3014.2	3579.6	3291.8	3579.6
1929-30							1194.4	1289.6	1381.8	1372.8	1741.8	3002.4	3369.3	"
1930-31							1441.0	1765.4	1793.6	1758.0	1975.9	2857.4	3313.5	"
1931-32							0.0	0.0	0.0	0.0	220.7	1692.5	2935.3	"
1932-33							314.2	228.8	268.4	233.9	462.5	1736.1	2869.3	"
1933-34							0.0	0.0	0.0	22.3	533.5	2164.4	3365.4	"
1934-35							610.6	763.8	953.5	960.9	1159.6	2230.4	3009.4	"
1935-36							711.7	559.5	572.2	502.8	710.4	2205.8	3291.0	"
1936-37							2782.3	3210.8	3207.3	3108.9	3260.9	3579.6	3361.4	"
1937-38							887.7	1113.2	1181.1	1183.3	1444.5	2561.5	3181.6	"
1938-39							1362.8	1541.4	1580.9	1545.3	1841.0	2947.1	3434.8	"
1939-40							1103.3	1086.1	1210.6	1282.6	1633.1	2726.1	3391.1	"
1940-41							1928.1	2450.2	2515.9	2602.1	3043.3	3579.6	3579.6	"
1941-42							1899.3	2426.2	2485.0	2416.8	2623.2	3401.1	3416.0	"
1942-43							2360.3	2818.6	2851.7	2768.0	3067.2	3579.6	3579.6	"
1943-44							3294.5	3579.6	3579.6	3579.6	3579.6	"	"	"
1944-45							2651.8	3179.7	3224.7	3183.3	3309.2	"	3522.5	"
1945-46							244.1	123.8	130.1	127.7	372.1	1677.8	3073.6	"
1946-47							752.1	582.4	586.1	604.3	864.3	2196.5	3173.0	"
1947-48							583.0	454.2	450.9	413.6	592.1	1792.7	3100.9	"
1948-49							2034.9	2525.9	2580.9	2523.5	2759.9	3579.6	3579.6	"
1949-50							471.8	475.3	531.1	484.9	714.6	1861.2	2745.0	"
1950-51							775.6	851.5	964.6	900.6	1202.6	2301.1	3244.2	"
1951-52							808.9	1209.1	1274.6	1195.2	1405.8	2642.1	3213.6	"
1952-53							1390.4	1893.4	1961.5	1904.7	2058.1	2906.3	3194.3	"
1953-54							14.1	0.0	0.0	0.0	206.1	1419.7	2878.9	"
1954-55							550.9	976.6	1087.7	1036.0	1278.5	2275.0	2724.7	"
1955-56							253.8	166.9	237.1	187.8	453.4	1919.5	3103.6	"
1956-57							322.7	378.5	455.4	406.8	665.8	1862.1	3244.6	"
1957-58							121.2	38.1	167.4	208.0	549.9	1788.9	3140.2	"
DISTRIBUTION FACTORS							0.9740	0.9770	0.9710	0.9750	0.9520	0.7430	0.4680	N/A
FORECAST ERRORS (KSFD)							1485.0	1095.0	954.0	810.0	810.0	723.0	679.0	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	7322	5079	23024	66715
VARIABLE REFILL CURVES						80 MAF	5000	5000	5000	5000	5000	5000	42000	53000
(BY VOLUME RUNOFF AT THE DALLE						95 MAF	5000	5000	5000	5000	5000	5000	42000	53000
						110 MAF	5000	5000	5000	5000	5000	5000	42000	53000
VARIABLE REFILL CURVE LOWER LIMIT						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)							401.3	21.7	0.0	0.0				

TABLE 6
(English Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2014 - 15 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	31.4	91.8	158.1	188.7	206.3	217.4	227.6	236.8	250.9	261.8	277.3	434.1	655.7	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							327.8	310.1	319.2	317.3	333.3	438.6	592.3	705.8
1929-30							326.2	308.1	317.0	314.7	338.4	459.0	604.1	"
1930-31							270.5	253.8	266.3	269.1	291.3	408.7	592.3	"
1931-32							0.0	0.0	0.0	5.5	40.1	223.7	501.9	"
1932-33							"	"	"	0.0	0.0	49.0	363.5	"
1933-34							8.9	11.0	36.1	50.5	96.1	302.9	574.6	"
1934-35							59.4	49.5	73.5	75.5	98.9	262.8	497.0	"
1935-36							35.9	20.2	32.9	33.5	60.3	259.7	553.7	"
1936-37							263.4	244.8	256.0	254.1	274.5	393.9	573.5	"
1937-38							52.6	43.6	60.8	69.5	99.0	272.6	530.7	"
1938-39							107.7	96.5	110.3	114.0	145.1	315.5	577.5	"
1939-40							94.7	88.3	109.9	123.1	156.8	318.4	563.6	"
1940-41							179.1	170.0	187.4	202.3	247.2	398.2	586.8	"
1941-42							172.0	165.3	182.6	186.3	215.0	360.3	567.3	"
1942-43							182.4	168.4	184.3	186.5	224.6	380.4	559.9	"
1943-44							333.9	320.8	334.6	334.6	357.7	465.6	623.4	"
1944-45							256.1	243.3	258.2	258.9	276.5	394.2	581.7	"
1945-46							0.0	0.0	0.0	0.0	0.0	164.8	499.6	"
1946-47							"	"	"	"	6.1	209.2	509.4	"
1947-48							15.3	3.4	22.3	23.1	47.2	226.4	524.3	"
1948-49							242.5	225.5	238.0	237.0	261.7	398.2	626.7	"
1949-50							41.7	25.2	40.5	40.1	65.8	230.1	459.4	"
1950-51							0.0	0.0	0.0	0.0	7.1	194.6	491.7	"
1951-52							72.6	58.1	76.7	77.3	102.5	287.4	542.7	"
1952-53							70.0	58.4	74.9	77.0	99.2	262.2	505.1	"
1953-54							0.0	0.0	0.0	0.0	0.0	124.3	434.3	"
1954-55							6.7	"	11.2	14.3	41.5	208.0	434.2	"
1955-56							0.0	"	0.0	0.0	0.0	175.2	492.5	"
1956-57							25.5	7.1	21.8	24.3	52.7	225.0	561.0	"
1957-58							0.0	0.0	0.0	0.0	0.0	164.9	512.7	"
DISTRIBUTION FACTORS							0.9750	0.9810	0.9760	0.9790	0.9580	0.7530	0.4820	N/A
FORECAST ERRORS (KSFD)							128.0	104.0	105.0	94.0	94.0	87.0	78.0	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	100	100	100	100	100	100	100	100	100	100	100	114	641	5705
VARIABLE REFILL CURVES					80	MAF	100	100	100	100	100	100	1200	2400
(BY VOLUME RUNOFF AT THE DALLE					95	MAF	100	100	100	100	100	100	1150	2400
					110	MAF	100	100	100	100	100	100	1100	2400
VARIABLE REFILL CURVE LOWER LIMIT					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)							125.5	4.4	0.0	0.0				

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2014 - 15 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	3203.9	3088.6	2960.8	2960.8	2960.8	3091.6	3529.2	3529.2
1929-30	,,	,,	,,	,,	,,	,,	3145.9	2978.5	2792.8	2792.8	2792.8	2825.9	3261.9	,,
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	2299.1	3387.3	"
1932-33	"	"	"	"	"	"	2691.3	2112.5	,,	,,	,,	1661.5	2868.9	"
1933-34	"	"	"	"	"	"	,,	,,	"	"	1838.3	2743.4	3216.5	"
1934-35	"	"	"	"	"	"	"	"	"	"	1472.2	1918.6	2873.0	"
1935-36	"	"	"	"	"	"	2698.3	2105.4	"	"	1556.5	2718.7	3529.2	"
1936-37	"	"	"	"	"	"	3109.9	2910.0	2688.3	2688.3	2688.3	2801.9	3394.7	"
1937-38	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1513.3	2307.3	3253.6	"
1938-39	"	"	"	"	"	"	2835.9	2387.7	1892.0	1892.0	1959.1	3159.2	3306.6	"
1939-40	"	"	"	"	"	"	2993.8	2677.7	2339.9	2339.9	2339.9	3117.7	3340.1	"
1940-41	"	"	"	"	"	"	3319.5	3308.6	3296.5	3296.5	3296.5	3337.0	3394.4	"
1941-42	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	1955.6	3280.3	"
1942-43	"	"	"	"	"	"	,,	,,	,,	,,	,,	1754.0	2831.9	"
1943-44	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3410.6	3529.2	"
1944-45	"	"	"	"	"	"	2829.2	2375.0	1872.6	1872.6	1872.6	2392.8	,,	"
1945-46	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2710.5	3296.8	"
1946-47	"	"	"	"	"	"	,,	,,	,,	,,	,,	2535.7	3529.2	"
1947-48	"	"	"	"	"	"	2698.3	2105.4	"	"	"	2327.9	,,	"
1948-49	"	"	"	"	"	"	2691.3	2112.5	"	"	1498.9	2430.8	3525.1	"
1949-50	"	"	"	"	"	"	,,	,,	"	"	1472.2	1472.2	2727.0	"
1950-51	"	"	"	"	"	"	"	"	"	"	,,	2469.8	3119.9	"
1951-52	"	"	"	"	"	"	2698.3	2105.4	"	"	1546.2	2498.6	3249.4	"
1952-53	"	"	"	"	"	"	2691.3	2112.5	"	"	1472.2	1953.5	3109.6	"
1953-54	"	"	"	"	"	"	,,	,,	"	"	,,	1863.0	2342.3	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1472.2	2926.5	3516.8
1955-56	"	"	"	"	"	"	2698.3	2105.4	"	"	"	2284.7	3282.4	3529.2
1956-57	"	"	"	"	"	"	2691.3	2112.5	"	"	"	3000.5	3529.2	"
1957-58	"	"	"	"	"	"	,,	,,	"	"	"	2574.8	,,	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2014 - 15 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	3188.4	3156.6	3121.4	3121.4	3121.4	3230.9	3579.6	3579.6
1929-30	,,	,,	,,	,,	,,	,,	3134.4	3053.9	2964.6	2964.6	2964.6	2964.6	,,	,,
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	2359.9	"	"
1932-33	"	"	"	"	"	"	2721.0	2267.2	,,	,,	,,	1764.6	3211.2	"
1933-34	"	"	"	"	"	"	,,	,,	"	"	2151.2	2445.2	3579.6	"
1934-35	"	"	"	"	"	"	"	"	"	"	1764.6	2036.8	,,	"
1935-36	"	"	"	"	"	"	2726.5	2261.7	"	"	2180.2	2889.9	"	"
1936-37	"	"	"	"	"	"	3100.7	2989.8	2866.9	2866.9	2866.9	2866.9	"	"
1937-38	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	2073.1	"	"
1938-39	"	"	"	"	"	"	2845.9	2504.8	2127.0	2127.0	2127.0	2283.9	"	"
1939-40	"	"	"	"	"	"	2990.9	2773.5	2540.8	2540.8	2540.8	3125.6	"	"
1940-41	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3342.5	"	"
1941-42	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	2004.2	2908.0	"
1942-43	"	"	"	"	"	"	,,	,,	,,	,,	2289.1	2612.2	3579.6	"
1943-44	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3297.0	,,	"
1944-45	"	"	"	"	"	"	2840.2	2493.8	2110.3	2110.3	2110.3	2201.4	"	"
1945-46	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	1933.4	"	"
1946-47	"	"	"	"	"	"	,,	,,	,,	,,	,,	2231.0	"	"
1947-48	"	"	"	"	"	"	2726.5	2261.7	"	"	"	2080.4	"	"
1948-49	"	"	"	"	"	"	2721.0	2267.2	"	"	"	2991.5	"	"
1949-50	"	"	"	"	"	"	,,	,,	"	"	"	1764.6	2621.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2107.6	3579.6	"
1951-52	"	"	"	"	"	"	2726.5	2261.7	"	"	1949.7	2724.7	,,	"
1952-53	"	"	"	"	"	"	2721.0	2267.2	"	"	1764.6	1764.6	"	"
1953-54	"	"	"	"	"	"	,,	,,	"	"	,,	2180.2	2675.7	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1770.0	2741.1	"
1955-56	"	"	"	"	"	"	2726.5	2261.7	"	"	1918.9	2626.7	3579.6	"
1956-57	"	"	"	"	"	"	2721.0	2267.2	"	"	1764.6	2664.8	,,	"
1957-58	"	"	"	"	"	"	,,	,,	"	"	,,	2697.5	"	"

TABLE 9
(English Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2014 - 15 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	432.4	705.8	705.8
1929-30	,,	,,	,,	,,	,,	,,	408.7	322.6	322.6	322.6	322.6	436.1	655.2	,,
1930-31	"	"	"	"	"	"	390.7	288.3	288.3	288.3	292.9	434.1	656.1	"
1931-32	"	"	"	"	"	"	277.3	65.5	65.5	65.5	65.5	275.5	626.4	"
1932-33	"	"	"	"	"	"	273.7	,,	,,	,,	,,	132.7	492.6	689.8
1933-34	"	"	"	"	"	"	,,	"	"	"	509.2	605.3	687.2	705.8
1934-35	"	"	"	"	"	"	"	"	"	"	65.5	168.0	485.5	"
1935-36	"	"	"	"	"	"	277.3	"	"	"	104.6	337.0	660.3	"
1936-37	"	"	"	"	"	"	374.8	258.1	258.1	258.1	258.1	377.6	621.2	"
1937-38	"	"	"	"	"	"	290.1	96.8	96.8	96.8	116.9	294.1	631.5	"
1938-39	"	"	"	"	"	"	285.1	87.2	87.2	87.2	111.9	337.7	558.6	"
1939-40	"	"	"	"	"	"	301.1	111.4	111.4	111.4	111.4	305.7	582.7	"
1940-41	"	"	"	"	"	"	344.4	200.1	200.1	200.1	216.3	372.0	619.8	"
1941-42	"	"	"	"	"	"	326.1	165.3	165.3	165.3	165.3	316.7	540.9	"
1942-43	"	"	"	"	"	"	329.3	171.4	171.4	171.4	171.4	241.9	443.9	"
1943-44	"	"	"	"	"	"	412.5	327.2	327.2	327.2	327.2	440.4	672.1	"
1944-45	"	"	"	"	"	"	381.5	270.7	270.7	270.7	270.7	393.8	653.6	"
1945-46	"	"	"	"	"	"	273.7	65.5	65.5	65.5	73.2	326.8	677.6	"
1946-47	"	"	"	"	"	"	,,	,,	,,	,,	83.5	314.0	637.9	"
1947-48	"	"	"	"	"	"	277.3	"	"	"	65.5	249.9	658.4	"
1948-49	"	"	"	"	"	"	368.0	245.0	245.0	245.0	264.3	485.5	705.8	"
1949-50	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	181.4	534.2	"
1950-51	"	"	"	"	"	"	,,	,,	,,	,,	,,	527.8	606.5	"
1951-52	"	"	"	"	"	"	277.3	"	"	"	95.6	295.4	595.0	"
1952-53	"	"	"	"	"	"	273.7	"	"	"	65.5	188.4	489.4	"
1953-54	"	"	"	"	"	"	,,	"	"	"	,,	189.7	435.6	689.2
1954-55	"	"	"	"	"	"	"	"	"	"	"	72.6	435.0	694.9
1955-56	"	"	"	"	"	"	277.3	"	"	"	"	321.0	636.6	705.8
1956-57	"	"	"	"	"	"	273.7	"	"	"	71.9	376.7	691.7	"
1957-58	"	"	"	"	"	"	,,	"	"	"	65.5	334.4	683.4	"

TABLE 10
(English Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2014 - 15 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3439.3	1878.2	1646.1	1762.6	1975.4	4114.2	6958.9	7814.6
1929-30	"	"	"	"	"	"	2643.9	1878.2	1646.1	1762.6	1975.4	4115.9	6709.3	,,
1930-31	"	"	"	"	"	"	3148.6	1878.2	1646.1	1762.6	1975.4	4090.5	6766.9	,,
1931-32	"	"	"	"	"	"	1522.1	795.0	654.2	684.6	1003.2	3420.8	6176.0	,,
1932-33	"	"	"	"	"	"	1428.6	960.3	922.6	907.2	1204.9	3289.7	5805.4	7798.6
1933-34	"	"	"	"	"	"	940.7	55.1	36.1	72.8	673.4	3757.2	6724.9	7814.6
1934-35	"	"	"	"	"	"	1906.7	1582.2	1460.7	1566.3	1763.6	3709.4	6147.2	,,
1935-36	"	"	"	"	"	"	1788.5	1338.1	1259.3	1215.4	1513.1	3941.5	6761.9	,,
1936-37	"	"	"	"	"	"	3437.8	1878.2	1646.1	1754.9	1956.2	4059.4	6997.6	,,
1937-38	"	"	"	"	"	"	2287.7	1685.0	1456.0	1570.3	1797.1	3850.3	6545.0	,,
1938-39	"	"	"	"	"	"	2735.6	1728.6	1482.4	1588.0	1810.0	3997.3	6977.5	,,
1939-40	"	"	"	"	"	"	2257.1	1729.7	1505.1	1612.2	1809.5	3987.5	6737.6	,,
1940-41	"	"	"	"	"	"	3353.5	1811.4	1582.6	1700.9	1914.4	4053.8	6996.2	,,
1941-42	"	"	"	"	"	"	3346.4	1806.7	1560.5	1666.1	1863.4	3825.5	6437.3	,,
1942-43	"	"	"	"	"	"	3356.8	1809.8	1566.6	1672.2	1869.5	3923.7	6596.3	,,
1943-44	"	"	"	"	"	"	3439.3	1878.2	1646.1	1762.6	1975.4	4115.9	7047.5	,,
1944-45	"	"	"	"	"	"	3430.5	1878.2	1646.1	1759.7	1968.8	4075.6	7005.8	,,
1945-46	"	"	"	"	"	"	1222.1	599.3	536.3	516.2	851.3	3185.5	6307.9	,,
1946-47	"	"	"	"	"	"	1686.8	1225.8	1188.9	1210.9	1592.9	3891.0	6486.8	,,
1947-48	"	"	"	"	"	"	1466.5	1025.7	989.0	930.2	1212.2	3417.9	6313.8	,,
1948-49	"	"	"	"	"	"	3416.9	1866.9	1633.2	1737.8	1959.8	4080.0	7050.8	,,
1949-50	"	"	"	"	"	"	1711.1	1269.4	1225.8	1204.1	1522.5	3418.2	5576.4	,,
1950-51	"	"	"	"	"	"	2006.2	1624.8	1395.2	1500.8	1705.2	3806.8	6601.1	,,
1951-52	"	"	"	"	"	"	2446.6	1699.5	1460.7	1566.3	1793.7	3969.2	6772.1	,,
1952-53	"	"	"	"	"	"	3107.0	1699.8	1460.7	1566.3	1763.6	3457.6	6665.7	,,
1953-54	"	"	"	"	"	"	1195.2	499.1	438.9	434.7	723.8	2859.4	5452.3	7798.0
1954-55	"	"	"	"	"	"	2105.4	1645.8	1406.4	1515.1	1739.6	3314.8	5824.8	7791.3
1955-56	"	"	"	"	"	"	1503.7	940.2	891.3	866.9	1195.8	3599.3	6374.0	7814.6
1956-57	"	"	"	"	"	"	1672.5	1154.5	1131.4	1110.2	1460.9	3591.7	6909.2	,,
1957-58	"	"	"	"	"	"	1506.0	811.4	821.6	887.1	1292.3	3458.4	6526.0	,,

TABLE 11
(English Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2014 - 15 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3439.3	1720.8	1180.7	1078.2	1129.4	2469.6	5928.3	7500.9
1929-30	7771.3	7781.8	7251.5	6374.4	5024.0	3435.6	1274.3	313.9	0.0	9.1	570.7	2277.8	4703.2	6907.3
1930-31	7420.1	7567.6	7251.5	6374.5	5023.2	3182.1	1433.3	266.9	0.0	0.0	2.0	1342.9	3697.7	4379.4
1931-32	4368.5	4331.3	4191.0	3279.0	2111.0	593.9	204.5	0.0	0.0	118.9	554.7	2796.6	6231.2	7752.6
1932-33	7814.6	7814.6	7291.2	6610.8	6430.6	5282.1	3182.7	1553.5	922.6	857.8	1012.3	2375.0	5773.3	7736.6
1933-34	7814.6	7814.6	7663.6	7339.4	6611.4	5334.9	3372.9	1755.8	828.3	679.4	1319.5	3757.2	6125.7	7465.2
1934-35	7726.2	7766.4	7177.4	6523.6	6611.4	5282.1	3192.7	1723.8	1300.7	1058.5	1103.6	2691.8	5802.3	7752.6
1935-36	7814.6	7808.3	7580.2	6906.6	5825.8	4004.6	1823.5	819.1	425.5	346.6	952.9	3932.3	6710.7	7752.6
1936-37	7810.8	7798.1	7322.0	6508.7	5211.4	3327.8	1275.2	311.4	0.0	8.7	8.5	1344.6	3997.4	5594.9
1937-38	5601.3	5611.2	5391.0	4714.5	4287.2	3140.9	2313.7	1685.0	641.9	541.2	675.0	2575.7	5658.3	7576.8
1938-39	7638.6	7684.3	7416.7	6827.6	5849.5	4616.1	2765.4	1726.8	1089.2	1121.3	1535.4	3669.1	5308.4	7432.0
1939-40	7648.4	7735.7	7177.4	6563.4	5666.0	4608.4	2495.1	1729.7	1487.3	1572.1	1809.5	3987.5	5591.4	7039.6
1940-41	7298.1	7280.0	7087.4	6841.4	5815.0	4056.0	2581.0	1295.4	1067.2	1311.5	1655.6	3213.2	4503.7	5640.8
1941-42	5650.3	5717.5	5867.0	6271.5	5902.3	5282.1	3346.4	1856.8	1065.3	945.0	1034.6	2776.6	5080.3	7495.6
1942-43	7681.3	7808.0	7461.2	6832.6	6257.8	5282.1	3356.8	1835.8	1196.4	1083.9	1286.9	2440.0	4837.1	7327.1
1943-44	7664.6	7814.6	7663.6	7339.4	6598.6	5282.1	3439.3	1775.3	1135.9	1103.9	1222.9	2249.0	4149.1	4782.6
1944-45	4857.8	4862.4	4652.6	3984.0	2926.6	1315.2	676.3	184.4	0.0	0.0	0.1	1673.1	4638.0	6240.8
1945-46	6164.6	6040.0	5747.1	5152.9	4375.8	3218.9	1251.9	599.3	216.5	181.2	464.2	2757.7	6194.2	7752.6
1946-47	7814.6	7814.6	7663.6	7300.9	6611.4	5282.1	3099.9	1473.3	1131.0	1155.9	1484.5	3819.4	6486.8	7814.6
1947-48	7814.6	7808.2	7663.6	7339.4	6611.4	5282.1	3126.4	1415.9	983.8	883.2	1090.5	3417.9	6313.8	7814.6
1948-49	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3416.9	1913.7	1521.5	1516.9	1886.3	4080.0	6495.8	7450.3
1949-50	7663.2	7781.8	7341.4	6788.6	6506.4	5282.1	3098.2	1465.4	1008.3	889.8	938.2	2118.3	5022.8	7814.6
1950-51	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3294.4	1685.9	1283.6	1306.4	1497.0	3771.6	6425.3	7814.6
1951-52	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3099.3	1699.5	1274.7	1081.6	1251.5	3450.5	6087.7	7752.6
1952-53	7814.6	7804.9	7478.4	6824.2	5769.9	4249.4	3134.4	1699.8	965.5	830.1	854.8	2287.5	5477.8	7386.2
1953-54	7664.6	7814.6	7663.6	7339.4	6611.4	5282.1	3158.6	1606.5	700.1	436.3	468.8	2576.8	5452.3	7798.0
1954-55	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3206.5	1645.8	1262.4	1229.2	994.4	2026.0	5397.3	7791.3
1955-56	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3223.6	1494.2	891.3	858.2	1195.8	3582.9	6374.0	7814.6
1956-57	7814.6	7814.6	7663.6	7339.4	6611.4	5282.1	3119.6	1489.7	1119.8	1087.9	1273.0	3591.7	6877.9	7752.6
1957-58	7709.0	7786.9	7365.3	6966.6	6217.1	5226.1	3093.0	1512.6	821.6	869.2	966.8	3378.3	6526.0	7752.6
Max	7814.6	7814.6	7663.6	7339.4	6611.4	5334.9	3439.3	1913.7	1521.5	1572.1	1886.3	4080.0	6877.9	7814.6
Median	7748.8	7806.5	7439.0	6837.0	6344.2	5282.1	3109.8	1580.0	996.1	886.5	1062.6	2767.2	5715.8	7656.7
Average	7331.0	7358.3	7100.5	6612.6	5837.8	4494.1	2649.8	1341.9	850.7	805.4	1008.0	2881.0	5595.6	7229.6
Min	4368.5	4331.3	4191.0	3279.0	2111.0	593.9	204.5	0.0	0.0	0.0	0.1	1342.9	3697.7	4379.4

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

	2006-07 through 2008-09 1/	2009-10	2010-11	2011-12 through 2013-14 2/	2014-15
MICA TARGET OPERATION (ksfd or cfs)					
AUG 15	3454.2	3454.2	3439.2	3364.2	3379.2
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	3428.4	3428.4	3428.4	3428.4	3428.4
NOV	20000	22000	21000	21000	22000
DEC	25000	25000	25000	25000	22000
JAN	24000	23000	27000	24000	24000
FEB	21000	20000	21000	21000	21000
MAR	18000	17000	21000	17000	25000
APR 15	18000	18000	22000	20000	17000
APR 30	12000	11000	10000	10000	10000
MAY	10000	10000	8000	8000	8000
JUN	10000	10000	8000	8000	10000
JUL	3379.2	3436.2	3467.2	3467.2	3467.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7786.1	7811.6	7794.1	7814.4	7814.6
1928 DEC	5133.8	5110.5	5086.0	5204.0	5282.1
1929 APR15	839.3	671.5	1048.2	1084.4	1078.2
1929 JUL	7147.7	7168.9	7233.2	7329.8	7500.9
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)					
Pre AOP15: 60-Yr Average, AOP15: 70-Yr Average 3/					
AUG 31	7360.7	7455.5	7438.0	7362.8	7406.8
DEC	4634.9	4640.3	4612.9	4630.0	4644.6
APR15	1178.5	877.8	842.6	908.6	889.3
JUL	7193.7	7277.6	7268.9	7147.1	7279.9
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.2	-0.3	-0.3	0.1	0.0
U.S. Dependable Peaking Capacity	-21.0	-2.7	-19.1	-22.9	-3.9
U.S. Average Annual Usable Secondary Energy	0.3	13.8	16.0	21.6	21.3
BCH Firm Energy	90.3	50.2	34.4	43.6	44.0
BCH Dependable Peaking Capacity	11.0	44.9	43.8	41.7	47.8
BCH Average Annual Usable Secondary Energy	-29.3	-28.2	-20.8	-13.9	-33.4
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	11137	11138	11138	10969	11187
AUG 31	11165	11166	11167	11104	10971
SEP	10849	10850	11025	11081	9756
OCT	9782	9783	9958	9920	9758
NOV	11157	11157	11333	11458	11821
DEC	13192	13193	13369	13316	13836
JAN	13075	13076	13076	12878	13323
FEB	11901	11901	11902	11721	13179
MAR	11315	11316	10967	10501	12022
APR 15	10589	10590	10241	9786	10476
APR 30	12822	12823	12475	11502	11012
MAY	13491	13491	13493	13287	12198
JUN	14079	14079	14080	13867	12208
JUL	12723	12724	12725	12531	11954
ANNUAL AVERAGE	12037	12038	12039	11856	11819

1/ The AOP/DDPB 2006-07, 2007-08 and 2008-09 utilize the same system regulation studies.

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

3/ Prior to AOP15, average content based on 60 years of modified flows. AOP15 average based on 70 years of modified flows.

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2014-15 ASSURED OPERATING PLAN

		Target Operation		Target Operation Limits		
Month	End of Previous Month **Arrow** Storage Content	Month Outflow (m^3/s)	End-of-Month Treaty Storage Content 1/ (hm^3)	Minimum Treaty Storage Content 2/ (hm^3)	Maximum Outflow 1/ (m^3/s)	Minimum Outflow (m^3/s)
August 1-15	8073.8 - FULL	-	8,267.6	-	962.77	424.75
	3547.6 - 8073.8	707.92	-	0.0	-	424.75
	0.0 - 3547.6	906.14	-	0.0	-	424.75
August 16-31	7486.6 - FULL	-	8,634.5	-	962.77	424.75
	3180.6 - 7486.6	707.92	-	0.0	-	424.75
	0.0 - 3180.6	906.14	-	0.0	-	424.75
September	8734.4 - FULL	-	8,634.5	-	962.77	283.17
	8514.2 - 8734.4	707.92	-	0.0	-	283.17
	5235.7 - 8514.2	764.55	-	0.0	-	283.17
	0.0 - 5235.7	906.14	-	0.0	-	283.17
October	8440.8 - FULL	-	8,387.9	-	962.77	283.17
	6997.3 - 8440.8	594.65	-	0.0	-	283.17
	3327.4 - 6997.3	707.92	-	0.0	-	283.17
	0.0 - 3327.4	906.14	-	0.0	-	283.17
November	8318.4 - FULL	622.97	-	0.0	-	283.17
	7413.2 - 8318.4	538.02	-	0.0	-	283.17
	2691.3 - 7413.2	707.92	-	0.0	-	283.17
	0.0 - 2691.3	906.14	-	0.0	-	283.17
December	7927.0 - FULL	622.97	-	499.4	-	283.17
	5871.8 - 7927.0	707.92	-	499.4	-	283.17
	1688.2 - 5871.8	764.55	-	499.4	-	283.17
	0.0 - 1688.2	906.14	-	499.4	-	283.17
January	5504.9 - FULL	679.60	-	499.4	-	339.80
	5407.0 - 5504.9	736.24	-	499.4	-	339.80
	3816.7 - 5407.0	792.87	-	499.4	-	339.80
	0.0 - 3816.7	821.19	-	499.4	-	339.80
February	3351.8 - FULL	594.65	-	0.0	-	339.80
	2299.8 - 3351.8	736.24	-	0.0	-	339.80
	2079.6 - 2299.8	622.97	-	0.0	-	339.80
	0.0 - 2079.6	736.24	-	0.0	-	339.80
March	1394.6 - FULL	707.92	-	0.0	-	339.80
	1076.5 - 1394.6	481.39	-	0.0	-	339.80
	391.5 - 1076.5	594.65	-	0.0	-	339.80
	0.0 - 391.5	736.24	-	0.0	-	339.80
April 1-15	1272.2 - FULL	481.39	-	0.0	-	339.80
	978.6 - 1272.2	339.80	-	0.0	-	339.80
	48.9 - 978.6	424.75	-	0.0	-	339.80
	0.0 - 48.9	594.65	-	0.0	-	339.80
April 16-30	2177.5 - FULL	283.17	-	0.0	-	283.17
	1198.8 - 2177.5	339.80	-	0.0	-	283.17
	97.9 - 1198.8	283.17	-	0.0	-	283.17
	0.0 - 97.9	424.75	-	0.0	-	283.17
May	391.5 - FULL	226.53	-	0.0	-	226.53
	48.9 - 391.5	283.17	-	0.0	-	226.53
	0.0 - 48.9	339.80	-	0.0	-	226.53
June	5235.7 - FULL	283.17	-	0.0	-	226.53
	3547.6 - 5235.7	226.53	-	0.0	-	226.53
	2789.1 - 3547.6	283.17	-	0.0	-	226.53
	0.0 - 2789.1	453.07	-	0.0	-	226.53
July	7608.9 - FULL	-	8,482.9	-	962.77	283.17
	7046.2 - 7608.9	-	8,331.2	-	962.77	283.17
	4036.9 - 7046.2	622.97	-	0.0	-	283.17
	0.0 - 4036.9	679.60	-	0.0	-	283.17

1/ If the Mica target end-of-month storage content is less than 8634.5 hm^3, then a maximum outflow of 962.77 m^3/s will apply.
2/ Mica outflows will be reduced to minimum to maintain the reservoir above the minimum Treaty storage content.
This will override any flow target.

TABLE 1.1aM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
DEFINITION
2014-15 ASSURED OPERATING PLAN

Period	Volume Runoff Period	The Dalles Volume Runoff (km^3)	Maximum Storage Limit 1/ 2/ (hm^3)	Maximum Outflow Limit 3/ (m^3/s)	Minimum Outflow Limit 4/ (m^3/s)
August 15 - December	-		URC	-	283.2
January	-		URC	1,982	283.2
February	1 Feb - 31 Jul	≤ 86	URC	1,699	566.3
		>86 to <99	URC to 4404		
		≥ 99	4404		
March	1 Mar - 31 Jul	≤ 80	URC	-	566.3
		>80 to <93	URC to 2202		
		≥ 93	2202		
April 15	1 Apr - 31 Jul	≤ 75	URC	-	424.8
		>75 to <86	URC to 2202		
		≥ 86	2202		
April 30	1 Apr - 31 Jul	≤ 75	URC	-	339.8
		>75 to <86	URC to 2447		
		≥ 86	2447		
May	1 May - 31 Jul	≤ 84	URC	-	283.2
		>84 to <86	URC to 5383		
		≥ 86	5383		
June	1 Jun - 31 Jul	≤ 41	URC	-	141.6
		>41 to <43	URC to 8074		
		≥ 43	8074		
July	-		URC	-	283.2

Notes:

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

2/ Interpolate when there are two values. For example, if the February-July volume runoff is between 86 km^3 and 99 km^3, then the Maximum Storage Limit is interpolated between February's URC and 4404 hm^3.

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

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

TABLE 1.1bM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
30 YEAR OPERATING DATA
FOR 2014-15 ASSURED OPERATING PLAN

	AUG15-DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
Maximum Average Monthly Flow Limits (m^3/s)									
	-	1,982	1,699	-	-	-	-	-	-
Minimum Average Monthly Flow Limits (m^3/s)									
	283.2	283.2	566.3	566.3	424.8	339.8	283.2	141.6	283.2
End-of-Period Maximum Storage Limits (hm^3)									
1928-29	-	-	URC	URC	URC	URC	URC	URC	-
1929-30	-	-	URC	URC	URC	URC	URC	URC	-
1930-31	-	-	URC	URC	URC	URC	URC	URC	-
1931-32	-	-	4403.9	2201.9	2201.9	2446.6	5382.5	8073.8	-
1932-33	-	-	4403.9	2201.9	2201.9	2446.6	URC	URC	-
1933-34	-	-	4403.9	2201.9	2201.9	2446.6	URC	URC	-
1934-35	-	-	4403.9	2201.9	2201.9	2446.6	URC	8073.8	-
1935-36	-	-	4465.0	2201.9	2201.9	2446.6	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	8682.5	-
1937-38	-	-	4403.9	2201.9	2201.9	2446.6	URC	8073.8	-
1938-39	-	-	4765.7	2349.7	3731.6	3851.7	URC	URC	-
1939-40	-	-	5390.6	3822.3	5708.4	5739.5	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	4403.9	2201.9	2201.9	2446.6	URC	URC	-
1942-43	-	-	4403.9	2201.9	2201.9	2446.6	5382.5	8073.8	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	4747.6	2732.6	3189.4	3352.3	URC	8073.8	-
1945-46	-	-	4403.9	2201.9	2201.9	2446.6	URC	8073.8	-
1946-47	-	-	4403.9	2201.9	2201.9	2446.6	5382.5	8073.8	-
1947-48	-	-	4403.9	2201.9	2201.9	2446.6	URC	8073.8	-
1948-49	-	-	4403.9	2201.9	2201.9	2446.6	URC	URC	-
1949-50	-	-	4403.9	2201.9	2201.9	2446.6	URC	URC	-
1950-51	-	-	4403.9	2201.9	2201.9	2446.6	URC	8073.8	-
1951-52	-	-	4403.9	2201.9	2201.9	2446.6	5382.5	8073.8	-
1952-53	-	-	4403.9	2201.9	2201.9	2446.6	URC	8073.8	-
1953-54	-	-	4403.9	2201.9	2201.9	2446.6	URC	URC	-
1954-55	-	-	4403.9	2201.9	2201.9	2446.6	URC	URC	-
1955-56	-	-	4403.9	2201.9	2201.9	2446.6	5382.5	8073.8	-
1956-57	-	-	4403.9	2201.9	2201.9	2446.6	5382.5	8073.8	-
1957-58	-	-	4403.9	2201.9	2201.9	2446.6	5382.5	8073.8	-

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2014 - 15 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8634.5	8543.8	8202.0	7332.9	6088.9	3892.8	1881.2	1152.8	1122.7	1149.4	2277.1	6303.4	8334.8
1929-30	8593.7	8597.1	7951.7	6909.9	5362.9	3811.3	1355.2	170.3	0.0	0.0	538.7	2128.8	5062.3	7679.6
1930-31	8221.6	8336.3	7951.0	6909.9	5357.6	3481.8	1347.3	87.3	0.0	0.0	0.0	1398.0	4317.8	5712.3
1931-32	5787.4	5736.5	5089.7	3906.0	2545.7	579.4	195.0	0.0						
							ARROW							
1928-29	8757.8	8757.8	8660.5	8210.1	7386.8	5890.4	3873.7	2134.7	1519.3	1285.2	1356.2	3220.0	6983.6	8451.8
1929-30	8714.3	8717.7	8063.0	6958.9	5400.4	3685.6	1398.5	580.6	0.0	22.3	776.6	3081.7	5545.0	7787.8
1930-31	8337.8	8454.0	8063.7	6961.1	5397.2	3368.5	1744.7	508.9	0.0	0.0	0.0	1498.1	3757.5	4233.8
1931-32	4316.3	4538.0	4917.4	3891.1	2496.8	873.7	305.3	0.0						
							DUNCAN							
1928-29	1726.8	1726.8	1545.5	1544.5	1455.7	943.9	648.1	194.3	216.5	230.0	257.6	545.1	1217.4	1565.1
1929-30	1705.3	1724.1	1726.8	1726.8	1528.4	908.7	364.1	17.1	0.0	0.0	81.0	362.3	899.6	1432.0
1930-31	1594.7	1724.6	1726.8	1725.1	1535.0	935.1	414.7	56.8	0.0	0.0	4.9	389.5	971.5	768.5
1931-32	584.2	322.5	246.6	225.3	122.3	0.0	0.0	0.0						
							COMPOSITE							
1928-29	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	8414.6	4210.1	2888.7	2637.9	2763.2	6042.1	14504.4	18351.7
1929-30	19013.3	19039.0	17741.5	15595.6	12291.7	8405.5	3117.7	768.0	0.0	22.3	1396.3	5572.9	11506.8	16899.4
1930-31	18154.0	18514.9	17741.5	15596.1	12289.8	7785.3	3506.7	653.0	0.0	0.0	4.9	3285.5	9046.8	10714.6
1931-32	10688.0	10597.0	10253.7	8022.4	5164.8	1453.0	500.3	0.0						

TABLE 4M
(Metric Units)
MICA
ASSURED AND VARIABLE REFILL CURVES, DISTRIBUTION FACTORS AND FORECAST ERRORS, POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2014 - 15 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	0.0	987.7	1424.7	1584.4	1624.5	1612.1	1583.9	1600.6	1661.5	1816.4	3681.2	7593.3	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							5402.1	4950.9	4810.7	4800.5	4899.1	6165.7	7522.8	8634.5
1929-30							2898.2	2345.8	2184.8	2221.8	2602.7	4690.1	6813.0	"
1930-31							3529.7	3000.5	2827.8	2810.9	3029.9	4736.4	7000.0	"
1931-32							2435.1	1921.3	1766.0	1752.3	2037.3	4020.3	6700.7	"
1932-33							2206.3	1778.9	1666.1	1647.3	1835.0	3774.1	6294.1	"
1933-34							204.5	0.0	0.0	0.0	107.2	3155.9	6923.4	"
1934-35							2864.0	2392.0	2308.6	2338.0	2507.5	4273.2	6489.1	"
1935-36							2327.5	1855.5	1744.7	1724.9	1955.3	4138.7	7137.2	"
1936-37							5369.6	4867.8	4691.6	4654.7	4870.9	6195.3	7601.8	"
1937-38							3118.2	2647.0	2490.9	2487.2	2713.0	4566.1	6930.5	"
1938-39							3051.6	2689.1	2550.8	2597.3	2867.4	4792.6	7580.5	"
1939-40							2515.8	2062.5	1967.3	1999.6	2314.7	4297.0	6981.4	"
1940-41							3982.8	3505.2	3379.5	3409.6	3840.9	5657.3	7557.3	"
1941-42							4089.5	3621.5	3475.6	3448.5	3633.0	5290.8	7311.4	"
1942-43							4678.1	4155.6	4001.9	3973.8	4345.2	6093.5	7526.0	"
1943-44							5628.2	5088.4	4945.3	4930.4	5096.8	6462.2	7951.0	"
1944-45							5450.3	5000.9	4891.7	4903.0	5022.9	6282.9	7748.9	"
1945-46							1701.1	1152.6	993.8	950.5	1172.4	3285.5	6690.7	"
1946-47							1979.8	1563.4	1474.8	1484.1	1767.7	3920.2	6861.2	"
1947-48							1854.5	1387.5	1262.0	1207.4	1401.7	3422.3	6577.9	"
1948-49							6009.6	5488.5	5292.7	5262.1	5450.3	6771.7	8507.6	"
1949-50							2725.0	2163.0	1978.8	1935.0	2140.5	3960.8	6106.0	"
1950-51							2703.7	2258.5	2152.5	2152.3	2429.0	4250.7	7010.0	"
1951-52							3699.7	3152.2	2982.9	2924.2	3122.4	4969.8	7378.5	"
1952-53							4388.7	3886.2	3739.6	3711.2	3855.6	5347.5	7295.8	"
1953-54							1635.3	1157.2	1073.8	1063.5	1266.6	3218.3	6036.3	"
1954-55							3496.2	3060.9	2955.5	2959.2	3169.1	4790.2	6522.4	"
1955-56							2390.1	1909.6	1754.5	1717.3	1932.3	4002.4	6796.4	"
1956-57							2803.1	2305.4	2185.8	2178.0	2394.7	4212.1	7623.1	"
1957-58							2395.7	1929.1	1825.7	1831.5	2087.4	3960.8	7029.3	"
DISTRIBUTION FACTORS							0.9760	0.9800	0.9760	0.9820	0.9660	0.7910	0.5060	N/A
FORECAST ERRORS (hm^3)							1781.1	1277.1	1113.2	1027.6	1027.6	981.1	971.3	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	98.49	193.52	1211.00
VARIABLE REFILL CURVES					98.68 km^3		84.95	84.95	84.95	84.95	84.95	84.95	622.97	849.50
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		84.95	84.95	84.95	84.95	84.95	84.95	622.97	849.50
					135.69 km^3		84.95	84.95	84.95	84.95	84.95	84.95	622.97	849.50
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(By VOLUME RUNOFF AT THE DALLES)					117.18 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							1012.6	54.8	0.0	0.0				

TABLE 5M
(Metric Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES, DISTRIBUTION FACTORS AND FORECAST ERRORS, POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2014 - 15 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1316.3	1812.9	2010.4	2338.2	5326.7	8123.9	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							6050.4	7207.9	7225.3	7054.8	7374.5	8757.8	8053.7	8757.8
1929-30							2922.2	3155.1	3380.7	3358.7	4261.5	7345.7	8243.3	"
1930-31							3525.6	4319.2	4388.2	4301.1	4834.2	6990.9	8106.8	"
1931-32							0.0	0.0	0.0	0.0	540.0	4140.9	7181.5	"
1932-33							768.7	559.8	656.7	572.3	1131.6	4247.5	7020.0	"
1933-34							0.0	0.0	0.0	54.6	1305.3	5295.4	8233.8	"
1934-35							1493.9	1868.7	2332.8	2350.9	2837.1	5456.9	7362.8	"
1935-36							1741.2	1368.9	1399.9	1230.2	1738.1	5396.7	8051.8	"
1936-37							6807.2	7855.5	7847.0	7606.2	7978.1	8757.8	8224.0	"
1937-38							2171.8	2723.6	2889.7	2895.1	3534.1	6267.0	7784.1	"
1938-39							3334.2	3771.2	3867.8	3780.7	4504.2	7210.4	8403.6	"
1939-40							2699.3	2657.3	2961.9	3138.0	3995.5	6669.7	8296.7	"
1940-41							4717.3	5994.7	6155.4	6366.3	7445.7	8757.8	8757.8	"
1941-42							4646.8	5935.9	6079.8	5912.9	6417.9	8321.1	8357.6	"
1942-43							5774.7	6896.0	6977.0	6772.2	7504.2	8757.8	8757.8	"
1943-44							8060.3	8757.8	8757.8	8757.8	8757.8	"	"	"
1944-45							6487.9	7779.5	7889.6	7788.3	8096.3	"	8618.1	"
1945-46							597.2	302.9	318.3	312.4	910.4	4104.9	7519.9	"
1946-47							1840.1	1424.9	1434.0	1478.5	2114.6	5374.0	7763.1	"
1947-48							1426.4	1111.2	1103.2	1011.9	1448.6	4386.0	7586.7	"
1948-49							4978.6	6179.9	6314.4	6174.0	6752.4	8757.8	8757.8	"
1949-50							1154.3	1162.9	1299.4	1186.4	1748.3	4553.6	6715.9	"
1950-51							1897.6	2083.3	2360.0	2203.4	2942.3	5629.9	7937.3	"
1951-52							1979.1	2958.2	3118.4	2924.2	3439.4	6464.2	7862.4	"
1952-53							3401.8	4632.4	4799.0	4660.0	5035.3	7110.6	7815.2	"
1953-54							34.5	0.0	0.0	0.0	504.2	3473.4	7043.5	"
1954-55							1347.8	2389.3	2661.2	2534.7	3128.0	5566.0	6666.3	"
1955-56							620.9	408.3	580.1	459.5	1109.3	4696.2	7593.3	"
1956-57							789.5	926.0	1114.2	995.3	1628.9	4555.8	7938.2	"
1957-58							296.5	93.2	409.6	508.9	1345.4	4376.7	7682.8	"
DISTRIBUTION FACTORS							0.9740	0.9770	0.9710	0.9750	0.9520	0.7430	0.4680	N/A
FORECAST ERRORS (hm^3)							3633.2	2679.0	2334.1	1981.7	1981.7	1768.9	1661.2	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	207.34	143.82	651.97	1889.16
VARIABLE REFILL CURVES					98.68 km^3		141.58	141.58	141.58	141.58	141.58	141.58	1189.31	1500.79
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		141.58	141.58	141.58	141.58	141.58	141.58	1189.31	1500.79
					135.69 km^3		141.58	141.58	141.58	141.58	141.58	141.58	1189.31	1500.79
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(By VOLUME RUNOFF AT THE DALLES)					117.18 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							981.8	53.1	0.0	0.0				

TABLE 6M
(Metric Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES,
DISTRIBUTION FACTORS AND FORECAST ERRORS,
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2014 - 15 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	76.8	224.6	386.8	461.7	504.7	531.9	556.8	579.4	613.9	640.5	678.4	1062.1	1604.2	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							802.0	758.7	781.0	776.3	815.5	1073.1	1449.1	1726.8
1929-30							798.1	753.8	775.6	769.9	827.9	1123.0	1478.0	"
1930-31							661.8	620.9	651.5	658.4	712.7	999.9	1449.1	"
1931-32							0.0	0.0	0.0	13.5	98.1	547.3	1227.9	"
1932-33							"	"	"	0.0	0.0	119.9	889.3	"
1933-34							21.8	26.9	88.3	123.6	235.1	741.1	1405.8	"
1934-35							145.3	121.1	179.8	184.7	242.0	643.0	1216.0	"
1935-36							87.8	49.4	80.5	82.0	147.5	635.4	1354.7	"
1936-37							644.4	598.9	626.3	621.7	671.6	963.7	1403.1	"
1937-38							128.7	106.7	148.8	170.0	242.2	666.9	1298.4	"
1938-39							263.5	236.1	269.9	278.9	355.0	771.9	1412.9	"
1939-40							231.7	216.0	268.9	301.2	383.6	779.0	1378.9	"
1940-41							438.2	415.9	458.5	494.9	604.8	974.2	1435.7	"
1941-42							420.8	404.4	446.7	455.8	526.0	881.5	1388.0	"
1942-43							446.3	412.0	450.9	456.3	549.5	930.7	1369.9	"
1943-44							816.9	784.9	818.6	818.6	875.1	1139.1	1525.2	"
1944-45							626.6	595.3	631.7	633.4	676.5	964.4	1423.2	"
1945-46							0.0	0.0	0.0	0.0	0.0	403.2	1222.3	"
1946-47							"	"	"	"	14.9	511.8	1246.3	"
1947-48							37.4	8.3	54.6	56.5	115.5	553.9	1282.8	"
1948-49							593.3	551.7	582.3	579.8	640.3	974.2	1533.3	"
1949-50							102.0	61.7	99.1	98.1	161.0	563.0	1124.0	"
1950-51							0.0	0.0	0.0	0.0	17.4	476.1	1203.0	"
1951-52							177.6	142.1	187.7	189.1	250.8	703.2	1327.8	"
1952-53							171.3	142.9	183.3	188.4	242.7	641.5	1235.8	"
1953-54							0.0	0.0	0.0	0.0	0.0	304.1	1062.6	"
1954-55							16.4	"	27.4	35.0	101.5	508.9	1062.3	"
1955-56							0.0	"	0.0	0.0	0.0	428.6	1205.0	"
1956-57							62.4	17.4	53.3	59.5	128.9	550.5	1372.5	"
1957-58							0.0	0.0	0.0	0.0	0.0	403.4	1254.4	"
DISTRIBUTION FACTORS							0.9750	0.9810	0.9760	0.9790	0.9580	0.7530	0.4820	N/A
FORECAST ERRORS (hm^3)							313.2	254.4	256.9	230.0	230.0	212.9	190.8	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	3.23	18.15	161.55
VARIABLE REFILL CURVES					98.68 km^3		2.83	2.83	2.83	2.83	2.83	2.83	33.98	67.96
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		2.83	2.83	2.83	2.83	2.83	2.83	32.56	67.96
					135.69 km^3		2.83	2.83	2.83	2.83	2.83	2.83	31.15	67.96
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(By VOLUME RUNOFF AT THE DALLES)					117.18 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69 km^3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							307.0	10.8	0.0	0.0				

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2014 - 15 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8634.5	8634.5	8634.5	8387.9	8387.9	8151.1	7838.7	7556.6	7243.9	7243.9	7243.9	7563.9	8634.5	8634.5
1929-30	"	"	"	"	"	"	7696.8	7287.2	6832.9	6832.9	6832.9	6913.8	7980.6	"
1930-31	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8151.1	8634.5	"
1931-32	"	"	"	"	"	"	6601.7	5151.1	3601.9	3601.9	3601.9	5625.0	8287.4	"
1932-33	"	"	"	"	"	"	6584.5	5168.4	"	"	"	4065.0	7019.1	"
1933-34	"	"	"	"	"	"	"	"	"	"	4497.6	6712.0	7869.5	"
1934-35	"	"	"	"	"	"	"	"	"	"	3601.9	4694.0	7029.1	"
1935-36	"	"	"	"	"	"	6601.7	5151.1	"	"	3808.1	6651.6	8634.5	"
1936-37	"	"	"	"	"	"	7608.7	7119.6	6577.2	6577.2	6577.2	6855.1	8305.5	"
1937-38	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3702.4	5645.0	7960.3	"
1938-39	"	"	"	"	"	"	6938.3	5841.7	4629.0	4629.0	4793.1	7729.3	8089.9	"
1939-40	"	"	"	"	"	"	7324.6	6551.3	5724.8	5724.8	5724.8	7627.8	8171.9	"
1940-41	"	"	"	"	"	"	8121.5	8094.8	8065.2	8065.2	8065.2	8164.3	8304.7	"
1941-42	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	4784.6	8025.6	"
1942-43	"	"	"	"	"	"	"	"	"	"	"	4291.3	6928.5	"
1943-44	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8344.4	8634.5	"
1944-45	"	"	"	"	"	"	6921.9	5810.7	4581.5	4581.5	4581.5	5854.2	"	"
1945-46	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	6631.5	8066.0	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	6203.8	8634.5	"
1947-48	"	"	"	"	"	"	6601.7	5151.1	"	"	"	5695.4	"	"
1948-49	"	"	"	"	"	"	6584.5	5168.4	"	"	3667.2	5947.2	8624.5	"
1949-50	"	"	"	"	"	"	"	"	"	"	3601.9	3601.9	6671.9	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	6042.6	7633.1	"
1951-52	"	"	"	"	"	"	6601.7	5151.1	"	"	3782.9	6113.1	7950.0	"
1952-53	"	"	"	"	"	"	6584.5	5168.4	"	"	3601.9	4779.4	7607.9	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	4558.0	5730.7	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	3601.9	7160.0	8604.2
1955-56	"	"	"	"	"	"	6601.7	5151.1	"	"	"	5589.7	8030.7	8634.5
1956-57	"	"	"	"	"	"	6584.5	5168.4	"	"	"	7341.0	8634.5	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6299.5	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2014 - 15 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8757.8	8757.8	8757.8	8449.6	8449.6	7887.1	7800.7	7722.9	7636.8	7636.8	7636.8	7904.7	8757.8	8757.8
1929-30	"	"	"	"	"	"	7668.6	7471.7	7253.2	7253.2	7253.2	7253.2	"	"
1930-31	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8757.8	"	"
1931-32	"	"	"	"	"	"	6670.7	5533.5	4317.3	4317.3	4317.3	5773.7	"	"
1932-33	"	"	"	"	"	"	6657.2	5546.9	"	"	"	4317.3	7856.5	"
1933-34	"	"	"	"	"	"	"	"	"	"	5263.1	5982.4	8757.8	"
1934-35	"	"	"	"	"	"	"	"	"	"	4317.3	4983.2	"	"
1935-36	"	"	"	"	"	"	6670.7	5533.5	"	"	5334.1	7070.4	"	"
1936-37	"	"	"	"	"	"	7586.2	7314.8	7014.2	7014.2	7014.2	7014.2	"	"
1937-38	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	5072.0	"	"
1938-39	"	"	"	"	"	"	6962.8	6128.2	5203.9	5203.9	5203.9	5587.8	"	"
1939-40	"	"	"	"	"	"	7317.5	6785.6	6216.3	6216.3	6216.3	7647.1	"	"
1940-41	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8177.8	"	"
1941-42	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	4903.5	7114.7	"
1942-43	"	"	"	"	"	"	"	"	"	"	5600.5	6391.0	8757.8	"
1943-44	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8066.4	"	"
1944-45	"	"	"	"	"	"	6948.8	6101.3	5163.1	5163.1	5163.1	5385.9	"	"
1945-46	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	4730.3	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	5458.4	"	"
1947-48	"	"	"	"	"	"	6670.7	5533.5	"	"	"	5089.9	"	"
1948-49	"	"	"	"	"	"	6657.2	5546.9	"	"	"	7319.0	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	4317.3	6413.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	5156.5	8757.8	"
1951-52	"	"	"	"	"	"	6670.7	5533.5	"	"	4770.1	6666.3	"	"
1952-53	"	"	"	"	"	"	6657.2	5546.9	"	"	4317.3	4317.3	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	5334.1	6546.4	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	4330.5	6706.4	"
1955-56	"	"	"	"	"	"	6670.7	5533.5	"	"	4694.8	6426.5	8757.8	"
1956-57	"	"	"	"	"	"	6657.2	5546.9	"	"	4317.3	6519.7	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6599.7	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2014 - 15 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	1726.8	1726.8	1726.8	1726.8	1726.8	1233.3	1022.7	832.6	832.6	832.6	832.6	1057.9	1726.8	1726.8
1929-30	"	"	"	"	"	"	999.9	789.3	789.3	789.3	789.3	1067.0	1603.0	"
1930-31	"	"	"	"	"	"	955.9	705.4	705.4	705.4	716.6	1062.1	1605.2	"
1931-32	"	"	"	"	"	"	678.4	160.3	160.3	160.3	160.3	674.0	1532.6	"
1932-33	"	"	"	"	"	"	669.6	"	"	"	"	324.7	1205.2	1687.7
1933-34	"	"	"	"	"	"	"	"	"	"	1245.8	1480.9	1681.3	1726.8
1934-35	"	"	"	"	"	"	"	"	"	"	160.3	411.0	1187.8	"
1935-36	"	"	"	"	"	"	678.4	"	"	"	255.9	824.5	1615.5	"
1936-37	"	"	"	"	"	"	917.0	631.5	631.5	631.5	631.5	923.8	1519.8	"
1937-38	"	"	"	"	"	"	709.8	236.8	236.8	236.8	286.0	719.5	1545.0	"
1938-39	"	"	"	"	"	"	697.5	213.3	213.3	213.3	273.8	826.2	1366.7	"
1939-40	"	"	"	"	"	"	736.7	272.6	272.6	272.6	272.6	747.9	1425.6	"
1940-41	"	"	"	"	"	"	842.6	489.6	489.6	489.6	529.2	910.1	1516.4	"
1941-42	"	"	"	"	"	"	797.8	404.4	404.4	404.4	404.4	774.8	1323.4	"
1942-43	"	"	"	"	"	"	805.7	419.3	419.3	419.3	419.3	591.8	1086.0	"
1943-44	"	"	"	"	"	"	1009.2	800.5	800.5	800.5	800.5	1077.5	1644.4	"
1944-45	"	"	"	"	"	"	933.4	662.3	662.3	662.3	662.3	963.5	1599.1	"
1945-46	"	"	"	"	"	"	669.6	160.3	160.3	160.3	179.1	799.5	1657.8	"
1946-47	"	"	"	"	"	"	"	"	"	"	204.3	768.2	1560.7	"
1947-48	"	"	"	"	"	"	678.4	"	"	"	160.3	611.4	1610.8	"
1948-49	"	"	"	"	"	"	900.3	599.4	599.4	599.4	646.6	1187.8	1726.8	"
1949-50	"	"	"	"	"	"	669.6	160.3	160.3	160.3	160.3	443.8	1307.0	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	1291.3	1483.9	"
1951-52	"	"	"	"	"	"	678.4	"	"	"	233.9	722.7	1455.7	"
1952-53	"	"	"	"	"	"	669.6	"	"	"	160.3	460.9	1197.4	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	464.1	1065.7	1686.2
1954-55	"	"	"	"	"	"	"	"	"	"	"	177.6	1064.3	1700.1
1955-56	"	"	"	"	"	"	678.4	"	"	"	"	785.4	1557.5	1726.8
1956-57	"	"	"	"	"	"	669.6	"	"	"	175.9	921.6	1692.3	"
1957-58	"	"	"	"	"	"	"	"	"	"	160.3	818.1	1672.0	"

TABLE 10M
(Metric Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2014 - 15 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	8414.6	4595.2	4027.3	4312.4	4833.0	10065.8	17025.6	19119.2
1929-30	"	"	"	"	"	"	6468.6	4595.2	4027.3	4312.4	4833.0	10070.0	16415.0	"
1930-31	"	"	"	"	"	"	7703.4	4595.2	4027.3	4312.4	4833.0	10007.8	16555.9	"
1931-32	"	"	"	"	"	"	3724.0	1945.0	1600.6	1674.9	2454.4	8369.3	15110.2	"
1932-33	"	"	"	"	"	"	3495.2	2349.5	2257.2	2219.6	2947.9	8048.6	14203.5	19080.1
1933-34	"	"	"	"	"	"	2301.5	134.8	88.3	178.1	1647.5	9192.4	16453.1	19119.2
1934-35	"	"	"	"	"	"	4664.9	3871.0	3573.7	3832.1	4314.8	9075.4	15039.7	"
1935-36	"	"	"	"	"	"	4375.7	3273.8	3081.0	2973.6	3702.0	9643.3	16543.7	"
1936-37	"	"	"	"	"	"	8410.9	4595.2	4027.3	4293.5	4786.0	9931.7	17120.3	"
1937-38	"	"	"	"	"	"	5597.1	4122.5	3562.2	3841.9	4396.8	9420.1	16013.0	"
1938-39	"	"	"	"	"	"	6692.9	4229.2	3626.8	3885.2	4428.3	9779.8	17071.2	"
1939-40	"	"	"	"	"	"	5522.2	4231.9	3682.4	3944.4	4427.1	9755.8	16484.2	"
1940-41	"	"	"	"	"	"	8204.7	4431.8	3872.0	4161.4	4683.8	9918.0	17116.9	"
1941-42	"	"	"	"	"	"	8187.3	4420.3	3817.9	4076.3	4559.0	9359.5	15749.5	"
1942-43	"	"	"	"	"	"	8212.7	4427.9	3832.8	4091.2	4573.9	9599.7	16138.5	"
1943-44	"	"	"	"	"	"	8414.6	4595.2	4027.3	4312.4	4833.0	10070.0	17242.4	"
1944-45	"	"	"	"	"	"	8393.1	4595.2	4027.3	4305.3	4816.9	9971.4	17140.4	"
1945-46	"	"	"	"	"	"	2990.0	1466.2	1312.1	1262.9	2082.8	7793.6	15432.9	"
1946-47	"	"	"	"	"	"	4126.9	2999.0	2908.8	2962.6	3897.2	9519.7	15870.6	"
1947-48	"	"	"	"	"	"	3587.9	2509.5	2419.7	2275.8	2965.8	8362.2	15447.3	"
1948-49	"	"	"	"	"	"	8359.8	4567.6	3995.8	4251.7	4794.8	9982.1	17250.5	"
1949-50	"	"	"	"	"	"	4186.4	3105.7	2999.0	2946.0	3724.9	8363.0	13643.2	"
1950-51	"	"	"	"	"	"	4908.4	3975.2	3413.5	3671.9	4171.9	9313.7	16150.3	"
1951-52	"	"	"	"	"	"	5985.9	4158.0	3573.7	3832.1	4388.5	9711.0	16568.6	"
1952-53	"	"	"	"	"	"	7601.6	4158.7	3573.7	3832.1	4314.8	8459.4	16308.3	"
1953-54	"	"	"	"	"	"	2924.2	1221.1	1073.8	1063.5	1770.8	6995.8	13339.6	19078.6
1954-55	"	"	"	"	"	"	5151.1	4026.6	3440.9	3706.8	4256.1	8110.0	14251.0	19062.2
1955-56	"	"	"	"	"	"	3679.0	2300.3	2180.7	2121.0	2925.6	8806.0	15594.6	19119.2
1956-57	"	"	"	"	"	"	4091.9	2824.6	2768.1	2716.2	3574.2	8787.5	16904.0	"
1957-58	"	"	"	"	"	"	3684.6	1985.2	2010.1	2170.4	3161.7	8461.3	15966.5	"

TABLE 11M
(Metric Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2014 - 15 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	8414.6	4210.1	2888.7	2637.9	2763.2	6042.1	14504.2	18351.7
1929-30	19013.3	19039.0	17741.5	15595.6	12291.7	8405.5	3117.7	768.0	0.0	22.3	1396.3	5572.9	11506.8	16899.4
1930-31	18154.0	18514.9	17741.5	15595.9	12289.8	7785.3	3506.7	653.0	0.0	0.0	4.9	3285.5	9046.8	10714.6
1931-32	10688.0	10597.0	10253.7	8022.4	5164.8	1453.0	500.3	0.0	0.0	290.9	1357.1	6842.2	15245.3	18967.5
1932-33	19119.2	19119.2	17838.6	16174.0	15733.1	12923.2	7786.8	3800.8	2257.2	2098.7	2476.7	5810.7	14125.0	18928.4
1933-34	19119.2	19119.2	18749.8	17956.6	16175.5	13052.4	8252.1	4295.7	2026.5	1662.2	3228.3	9192.4	14987.1	18264.4
1934-35	18902.9	19001.3	17560.2	15960.6	16175.5	12923.2	7811.3	4217.4	3182.3	2589.7	2700.1	6585.8	14195.9	18967.5
1935-36	19119.2	19103.8	18545.7	16897.7	14253.4	9797.7	4461.4	2004.0	1041.0	848.0	2331.4	9620.8	16418.4	18967.5
1936-37	19109.9	19078.8	17914.0	15924.2	12750.2	8141.8	3119.9	761.9	0.0	21.3	20.8	3289.7	9780.0	13688.5
1937-38	13704.1	13728.4	13189.6	11534.5	10489.1	7684.5	5660.7	4122.5	1570.5	1324.1	1651.5	6301.7	13843.6	18537.4
1938-39	18688.6	18800.4	18145.7	16704.4	14311.4	11293.8	6765.8	4224.8	2664.8	2743.4	3756.5	8976.8	12987.5	18183.1
1939-40	18712.6	18926.2	17560.2	16058.0	13862.4	11274.9	6104.5	4231.9	3638.8	3846.3	4427.1	9755.8	13679.9	17223.1
1940-41	17855.5	17811.2	17340.0	16738.2	14227.0	9923.4	6314.7	3169.3	2611.0	3208.7	4050.6	7861.4	11018.8	13800.8
1941-42	13824.0	13988.4	14354.2	15343.9	14440.6	12923.2	8187.3	4542.8	2606.4	2312.0	2531.3	6793.2	12429.5	18338.7
1942-43	18793.1	19103.1	18254.6	16716.6	15310.3	12923.2	8212.7	4491.5	2927.1	2651.9	3148.5	5969.7	11834.4	17926.5
1943-44	18752.2	19119.2	18749.8	17956.6	16144.1	12923.2	8414.6	4343.4	2779.1	2700.8	2991.9	5502.4	10151.2	11701.1
1944-45	11885.1	11896.3	11383.1	9747.3	7160.2	3217.8	1654.6	451.2	0.0	0.0	0.2	4093.4	11347.3	15268.7
1945-46	15082.3	14777.5	14060.9	12607.1	10705.8	7875.4	3062.9	1466.2	529.7	443.3	1135.7	6747.0	15154.7	18967.5
1946-47	19119.2	19119.2	18749.8	17862.4	16175.5	12923.2	7584.2	3604.6	2767.1	2828.0	3632.0	9344.5	15870.6	19119.2
1947-48	19119.2	19103.5	18749.8	17956.6	16175.5	12923.2	7649.1	3464.1	2407.0	2160.8	2668.0	8362.2	15447.3	19119.2
1948-49	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	8359.8	4682.1	3722.5	3711.2	4615.0	9982.1	15892.6	18227.9
1949-50	18748.8	19039.0	17961.5	16609.0	15918.6	12923.2	7580.1	3585.2	2466.9	2177.0	2295.4	5182.6	12288.8	19119.2
1950-51	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	8060.1	4124.7	3140.5	3196.2	3662.6	9227.6	15720.1	19119.2
1951-52	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	7582.7	4158.0	3118.7	2646.2	3061.9	8442.0	14894.2	18967.5
1952-53	19119.2	19095.5	18296.7	16696.1	14116.6	10396.6	7668.6	4158.7	2362.2	2030.9	2091.4	5596.6	13402.0	18071.1
1953-54	18752.2	19119.2	18749.8	17956.6	16175.5	12923.2	7727.8	3930.5	1712.9	1067.5	1147.0	6304.4	13339.6	19078.6
1954-55	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	7845.0	4026.6	3088.6	3007.4	2432.9	4956.8	13205.0	19062.2
1955-56	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	7886.9	3655.7	2180.7	2099.7	2925.6	8765.9	15594.6	19119.2
1956-57	19119.2	19119.2	18749.8	17956.6	16175.5	12923.2	7632.4	3644.7	2739.7	2661.7	3114.5	8787.5	16827.5	18967.5
1957-58	18860.8	19051.4	18019.9	17044.5	15210.8	12786.2	7567.3	3700.7	2010.1	2126.6	2365.4	8265.3	15966.5	18967.5
Max	19119.2	19119.2	18749.8	17956.6	16175.5	13052.4	8414.6	4682.1	3722.5	3846.3	4615.0	9982.1	16827.5	19119.2
Median	18958.1	19099.3	18200.1	16727.4	15521.7	12923.2	7608.3	3865.6	2436.9	2168.9	2599.6	6770.1	13984.3	18732.9
Average	17935.9	18002.9	17372.0	16178.5	14282.8	10995.3	6483.1	3283.0	2081.3	1970.5	2466.1	7048.7	13690.2	17687.8
Min	10688.0	10597.0	10253.7	8022.4	5164.8	1453.0	500.3	0.0	0.0	0.0	0.2	3285.5	9046.8	10714.6

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

	2006-07 through 2008-09 1/	2009-10	2010-11	2011-12 through 2013-14 2/	2014-15
MICA TARGET OPERATION (hm^3 or m^3/s)					
AUG 15	8451.0	8451.0	8414.3	8230.9	8267.6
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	8387.9	8387.9	8387.9	8387.9	8387.9
NOV	566.34	622.97	594.65	594.65	622.97
DEC	707.92	707.92	707.92	707.92	622.97
JAN	679.60	651.29	764.55	679.60	679.60
FEB	594.65	566.34	594.65	594.65	594.65
MAR	509.70	481.39	594.65	481.39	707.92
APR 15	509.70	509.70	622.97	566.34	481.39
APR 30	339.80	311.49	283.17	283.17	283.17
MAY	283.17	283.17	226.53	226.53	226.53
JUN	283.17	283.17	226.53	226.53	283.17
JUL	8267.6	8407.0	8482.9	8482.9	8482.9
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm3)					
1928 AUG 31	19049.5	19111.9	19069.0	19118.7	19119.2
1928 DEC	12560.4	12503.3	12443.4	12732.1	12923.2
1929 APR15	2053.4	1642.9	2564.5	2653.1	2637.9
1929 JUL	17487.6	17539.4	17696.7	17933.1	18351.7
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm3)					
Pre AOP15: 60-Yr Average, AOP15: 70-Yr Average 3/					
AUG 31	18008.7	18240.6	18197.7	18013.8	18121.4
DEC	11339.7	11353.0	11286.0	11327.8	11363.5
APR15	2883.3	2147.6	2061.6	2222.9	2175.9
JUL	17600.1	17805.4	17784.1	17486.1	17811.0
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.2	-0.3	-0.3	0.1	0.0
U.S. Dependable Peaking Capacity	-21.0	-2.7	-19.1	-22.9	-3.9
U.S. Average Annual Usable Secondary Energy	0.3	13.8	16.0	21.6	21.3
BCH Firm Energy	90.3	50.2	34.4	43.6	44.0
BCH Dependable Peaking Capacity	11.0	44.9	43.8	41.7	47.8
BCH Average Annual Usable Secondary Energy	-29.3	-28.2	-20.8	-13.9	-33.4
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	11137	11138	11138	10969	11187
AUG 31	11165	11166	11167	11104	10971
SEP	10849	10850	11025	11081	9756
OCT	9782	9783	9958	9920	9758
NOV	11157	11157	11333	11458	11821
DEC	13192	13193	13369	13316	13836
JAN	13075	13076	13076	12878	13323
FEB	11901	11901	11902	11721	13179
MAR	11315	11316	10967	10501	12022
APR 15	10589	10590	10241	9786	10476
APR 30	12822	12823	12475	11502	11012
MAY	13491	13491	13493	13287	12198
JUN	14079	14079	14080	13867	12208
JUL	12723	12724	12725	12531	11954
ANNUAL AVERAGE	12037	12038	12039	11856	11819

1/ The AOP/DDPB 2006-07, 2007-08 and 2008-09 utilize the same system regulation studies.

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

3/ Prior to AOP15, average content based on 60 years of modified flows. AOP15 average based on 70 years of modified flows.

Appendix A
Project Operating Procedures for the 2014-15 Assured Operating Plan and Determination of Downstream Power Benefits

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

Appendix A
Project Operating Procedures for the 2014-15 Assured Operating Plan and Determination of Downstream Power Benefits

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

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

Appendix A
Project Operating Procedures for the 2014-15
Assured Operating Plan and Determination of Downstream Power Benefits

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

	Kokanee Spawning	1.0 ft	0.30 m	Draft limit below Nov. 20th Elevation through Dec. 31st.	In place before AOP80 and supported by minimum contents noted above.
		0.5 ft	0.15 m	If project fills, draft no more than this amount.	
				Dec. 31 - Mar 31, operate between SMIN and URC within above noted draft limits.	
	Other Spill	50 cfs	1.4 m^3/s	All periods	
				None Noted	
Grand Coulee (1280)	Minimum Flow	30000 cfs	849.5 m^3/s	All periods	In place in AOP79, AOP80, AOP84.
	Minimum Content	0.0 ksfd	0.0 hm^3	Empty at end of CP.	
		1208.0 ft	368.20 m		
	Step I only:	843.9 ksfd	2064.7 hm^3	May and June	Retain as a power operation (for pumping).
		1240.0 ft	377.95 m		
	Steps II & III only:	857.9 ksfd	2098.9 hm^3	May and June	
		1240.0 ft	378.0 m		
	Maximum Content				
	Step I only:	2.0 ft	0.61 m	Operating room Sep - Nov	In place in AOP89
		3.0 ft	0.91 m	Operating room Dec - Feb	Retain as a power operation.
	Steps II & III only:	2557.1 ksfd	6256.1 hm^3	Aug-Nov	
		1288.0 ft	392.58 m		
		2518.3 ksfd	6161.2 hm^3	Dec-Feb	
		1287.0 ft	392.28 m		
	Draft Rate Limit	1.3 ft/day	0.40 m/day	(bank sloughage)	
		1.5 ft/day	0.46 m/day	(Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo.ave.)	
Chief Joseph (1270)	Other Spill	500 cfs	14.2 m^3/s	All periods	
Wells (1220)	Other Spill	1000 cfs	28.3 m^3/s	All periods	2/1/05 C. Wagers, Douglas With fish ladder
	Fish Spill			None	
Rocky Reach (1200)	Fish Spill/Bypass			None	
	Other Spill	200 cfs	5.7 m^3/s	Aug 31 - Apr 15 (leakage)	
Rock Island (1170)	Fish Spill/Bypass			None	
Wanapum (1165)	Fish Spill/Bypass			None	
	Other Spill	2200 cfs	62.3 m^3/s	All periods	With fish ladder

Appendix A
Project Operating Procedures for the 2014-15 Assured Operating Plan and Determination of Downstream Power Benefits

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

Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Spill/Bypass			None	
	Other Spill	2200 cfs	62.3 m^3/s	All periods	With fish ladder
Brownlee (767)	Minimum Flow	5850 cfs	165.7 m^3/s	All years, all periods in CP & LT studies.	4-04 C. Henriksen
	Downstream Minimum Flow	13000 cfs	368.1 m^3/s	July-Sep in all years for navigation requirement downstream at Lime Point (project #760). Draft Brownlee to help meet this requirement in CP and LT studies.	4-04 C. Henriksen
	Power Operation			Agree to use “old” power operation (first codes) provided by IPC and used in AOP since AOP97 for CP.	2-1-91 PNCA submittal
				LT run to PDP using rule curves from CP with BECC created from regulation spreadsheet to meet flow requirements at Lime Pt., and Brownlee and mimic the "old" historic first code operation on a 60 year average and median comparison. Consistent w/ TSR.	7-00 J. Hyde
Oxbow (765)	Other Spill	100 cfs	2.8 m^3/s	All periods	
Ice Harbor (502)	Fish Spill/Bypass			None	
	Other Spill	740 cfs	21.0 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow			None	
	Other	204.8 ksfd 440.0 ft	83.7 hm^3 134.11 m	Run at all periods	
McNary (488)	Other Spill	3475 cfs	98.4 m^3/s	All periods	
	Incremental Spill			None	
John Day (440)	Fish Spill/Bypass			None	
	Other Spill	800 cfs	22.7 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs 12500 cfs	1415.8 m^3/s 354.0 m^3/s	Mar - Nov Dec - Feb	

Appendix A
Project Operating Procedures for the 2014-15
Assured Operating Plan and Determination of Downstream Power Benefits

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

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

Appendix A
Project Operating Procedures for the 2014-15
Assured Operating Plan and Determination of Downstream Power Benefits

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Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
	776.9 ksfd	1900.7 hm^3	1929 Dec	2-1-93 PNCA submittal, in plac in AOP99.
	2363.0 ft	720.24 m		
	676.5 ksfd	1655.1 hm^3	1929 Jan	
	2355.0 ft	717.80 m		
	603.6 ksfd	1476.8 hm^3	1929 Feb	
	2349.0 ft	715.98 m		
	2147.7 ksfd	5254.5 hm^3	1929 Jul	
	2443.0 ft	744.63 m		
	652.0 ksfd	1595.2 hm^3	1930 Dec	
	2353.0 ft	717.19 m		
	433.2 ksfd	1059.9 hm^3	1930 Jan	
	2334.0 ft	711.40 m		
	389.3 ksfd	952.5 hm^3	1930 Feb	
	2330.0 ft	710.18 m		
	348.5 ksfd	852.6 hm^3	1930 Mar	
	2326.0 ft	708.96 m		
	297.4 ksfd	727.6 hm^3	1930 Apr 15	
	2321.0 ft	707.44 m		
	444.2 ksfd	1086.8 hm^3	1930 Apr 30	
	2335.0 ft	711.71 m		
	499.1 ksfd	1221.1 hm^3	1930 May	
	2340.0 ft	713.23 m		
	1344.6 ksfd	3289.7 hm^3	1930 Jun	
	2402.0 ft	732.13 m		
	1771.9 ksfd	4335.1 hm^3	1930 Jul	
	2425.0 ft	739.14 m		
	317.8 ksfd	777.5 hm^3	1931 Dec	
	2323.0 ft	708.05 m		
	192.2 ksfd	470.2 hm^3	1931 Jan	
	2310.0 ft	704.09 m		
	103.1 ksfd	252.2 hm^3	1931 Feb-Apr 30	
	2300.0 ft	701.04 m		
	192.2 ksfd	470.2 hm^3	1931 May	
	2310.0 ft	704.09 m		
	676.5 ksfd	1655.1 hm^3	1931 Jun	
	2355.0 ft	717.80 m		
	868.0 ksfd	2123.6 hm^3	1931 Jul	
	2370.0 ft	722.38 m		
	174.4 ksfd	426.7 hm^3	1932 Dec	
	2308.0 ft	703.48 m		
	103.1 ksfd	252.2 hm^3	1932 Jan	
	2300.0 ft	701.04 m		
	0.0 ksfd	0.0 hm^3	Empty at end of CP***	
	2287.0 ft	697.08 m		
	776.9 ksfd	1900.7 hm^3	All Dec	
	2363.0 ft	720.24 m		
		0.0 hm^3		
	373.1 ksfd	152.5 hm^3	July 1930 - No more than this amount lower than July 1929.	2-1-94 PNCA submittal, in place in AOP00 and AOP01.
	857.1 ksfd	350.3 hm^3	July 1931 - No more than this amount lower than July 1930.	
	March - Implement PNCA 6(c)2(c).			

Appendix A
Project Operating Procedures for the 2014-15 Assured Operating Plan and Determination of Downstream Power Benefits

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	Max Summer Draft	5.0 ft	1.52 m		
	Other			Operate to meet IJC orders for Corra Linn.	CRTOC agreement on procedures to implement 1938 IJC order.
Dworshak (535)	Minimum Flow	1300 cfs	36.8 m^3/s	All periods	2-11-02 PNCA submittal
	Maximum Flow	14000 cfs	396.4 m^3/s	All periods (model includes maximum 14000 cfs for all periods, but URC may override.)	2-11-02 PNCA submittal
		25000 cfs	707.9 m^3/s	Up to 25 kcfs for flood control all periods.	
	Minimum Content	395.8 ksfd	968.4 hm^3	SMIN Apr - Aug 31	
	Start 3 yr CP at:	395.8 ksfd	968.4 hm^3	Aug 15	
	End 3 yr CP at:	218.4 ksfd	534.3 hm^3	Feb	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements Oct-May and meets target operation Jun-Sep to obtain uniform ouflows Jul-Aug			2-1-05 PNCA submittal
	Target Operation:				
		779.3 ksfd	1906.6 hm^3	Jul	2-1-09 PNCA submittal
		1573.6 ft	479.63 m		Jul-Aug 15 and Sep based
		642.4 ksfd	1571.7 hm^3	Aug 15	on 70 Median .
		1556.0 ft	474.27 m		
		490.1 ksfd	1199.1 hm^3	Aug 31	
		1535.0 ft	467.87 m		
		392.9 ksfd	961.26 hm^3	Sep	
		1519.5 ft	463.14 m		
		1016 ksfd	2485.7 hm^3	Jun	
		1600.0 ft	487.68 m		
	Other Spill	100 cfs	2.8 m^3/s	All periods	
Lower Granite (520)	Bypass Date			None	
	Other Spill	450 cfs	12.7 m^3/s	Jul	2-1-09 PNCA submittal
		510 cfs	14.4 m^3/s	15-Aug	
		470 cfs	13.3 m^3/s	30-Aug	
		480 cfs	13.6 m^3/s	Sep	
		530 cfs	15.0 m^3/s	Oct	
		410 cfs	11.6 m^3/s	Nov	
		340 cfs	9.6 m^3/s	Dec	
		100 cfs	2.8 m^3/s	Jan	
		130 cfs	3.7 m^3/s	Feb	
		230 cfs	6.5 m^3/s	Mar	
		420 cfs	11.9 m^3/s	15-Apr	
		440 cfs	12.5 m^3/s	Apr 30 - May	
		460 cfs	13.0 m^3/s	Jun	
	Incremental Spill			Removed	
	Fish Spill				
		17333 cfs	490.8 m^3/s	Apr 15 [20 kcfs alternating for 13 days]	2-1-09 PNCA submittal
		20000 cfs	566.3 m^3/s	Apr 30 - May	
		18000 cfs	509.7 m^3/s	Jun - Aug 15	

Appendix A
Project Operating Procedures for the 2014-15
Assured Operating Plan and Determination of Downstream Power Benefits

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

	Maximum Fish Spill	20000 cfs	566.3 m^3/s	Apr 15 - May	
		18000 cfs	509.7 m^3/s	Jun - Aug 15	
	Minimum Flow	11500 cfs	325.6 m^3/s	All periods	
	Other	224.9 ksfd	550.2 hm^3	On MOP Apr - Oct 31.	
		733.0 ft	223.42 m		
		245.8 ksfd	601.4 hm^3	On full pool Nov 30 - Mar 31.	
		738.0 ft	224.94 m		
Little Goose (518)	Bypass Date			None	
	Other Spill	590 cfs	16.7 m^3/s	Jul	2-1-09 PNCA submittal
		620 cfs	17.6 m^3/s	15-Aug	
		500 cfs	14.2 m^3/s	30-Aug	
		750 cfs	21.2 m^3/s	Sep	
		640 cfs	18.1 m^3/s	Oct	
		500 cfs	14.2 m^3/s	Nov	
		460 cfs	13.0 m^3/s	Dec	
		120 cfs	3.4 m^3/s	Jan	
		240 cfs	6.8 m^3/s	Feb	
		380 cfs	10.8 m^3/s	Mar	
		530 cfs	15.0 m^3/s	15-Apr	
		580 cfs	16.4 m^3/s	Apr 30 - May	
		660 cfs	18.7 m^3/s	May	
		590 cfs	16.7 m^3/s	Jun	
	Incremental Spill			Removed	
	Fish Spill (% of outflow)	22%		Apr 15 [30%*11/15]	2-1-09 PNCA submittal
		30%		Apr 30 - Aug 15	
	Maximum Fish Spill	30000 cfs	849.5 m^3/s	Apr 15 - Apr 31	
		28000 cfs	792.9 m^3/s	May	
		30000 cfs	849.5 m^3/s	Jun	
		28000 cfs	792.9 m^3/s	Jul - Aug 15	
	Minimum Flow	11500 cfs	325.6 m^3/s	All periods	
	Other	260.5 ksfd	106.5 hm^3	On MOP Apr - Aug 31.	
		633.0 ft	192.94 m		
		285.0 ksfd	697.3 hm^3	On full pool Sep 30 - Mar 31.	
		638.0 ft	194.46 m		
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	790 cfs	22.4 m^3/s	Jul	2-1-09 PNCA submittal
		860 cfs	24.4 m^3/s	15-Aug	
		770 cfs	21.8 m^3/s	30-Aug	
		780 cfs	22.1 m^3/s	Sep	
		840 cfs	23.8 m^3/s	Oct	
		750 cfs	21.2 m^3/s	Nov	
		720 cfs	20.4 m^3/s	Dec	
		450 cfs	12.7 m^3/s	Jan	
		410 cfs	11.6 m^3/s	Feb	
		560 cfs	15.9 m^3/s	Mar	
		770 cfs	21.8 m^3/s	15-Apr	
		780 cfs	22.1 m^3/s	Apr 30 - May	
		840 cfs	23.8 m^3/s	May	
		780 cfs	22.1 m^3/s	Jun	
	Fish Spill	15600 cfs	441.7 m^3/s	Apr 15 [26000*(9/15)]	2-1-09 PNCA submittal
		25000 cfs	707.9 m^3/s	Apr 31	
		22000 cfs	623.0 m^3/s	May	
		17000 cfs	481.4 m^3/s	Jun - Aug 15	

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Project Operating Procedures for the 2014-15
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	Maximum Fish Spill	26000 cfs	736.2 m^3/s	Apr 15	
		25000 cfs	707.9 m^3/s	Apr 30	
		22000 cfs	623.0 m^3/s	May	
		17000 cfs	481.4 m^3/s	Jun - Aug 15	
	Minimum Flow	11500 cfs	325.6 m^3/s	All period	
	Other	180.5 ksfd	441.6 hm^3	On MOP Apr - Aug 31.	
		537.0 ft	163.68 m		
		190.1 ksfd	465.1 hm^3	On full pool Sep 30 - Mar 31.	
		540.0 ft	164.59 m		
Cushman (2206)	Other Spill	240 cfs	6.8 m^3/s	All periods	2-1-09 PNCA submittal
LaGrande (2188)	Other Spill	30 cfs	0.8 m^3/s	All periods	
White River (2160)	Other Spill	130 cfs	3.7 m^3/s	All periods	
Lower Baker (2025)	Max Storage Limits	67.0 ksfd	163.9 hm^3	Jul - Aug 31	2-1-05 PNCA submittal
		442.4 ft	134.84 m		
		40.1 ksfd	98.1 hm^3	Sep	
		415.9 ft	126.77 m		
		34.7 ksfd	84.9 hm^3	Oct - Dec	
		409.8 ft	124.91 m		
		45.2 ksfd	110.6 hm^3	Jan - Mar	
		421.4 ft	128.44 m		
		46.7 ksfd	114.3 hm^3	Apr 15	
		423.0 ft	128.93 m		
		67.0 ksfd	163.9 hm^3	Apr 30 - Jun	
		442.4 ft	134.84 m		
		11.2 ksfd	27.4 hm^3	All periods	
		378.8 ft	115.46 m		
Upper Baker (2028)	Max Storage Limits	107.4 ksfd	262.8 hm^3	Jul - Sep	2-1-05 PNCA submittal
		727.8 ft	221.83 m		
		82.3 ksfd	201.4 hm^3	Oct	
		717.0 ft	218.54 m		
		70.9 ksfd	173.5 hm^3	Nov - Feb	
		711.7 ft	216.93 m		
		107.4 ksfd	262.8 hm^3	Mar - Jun	
		727.8 ft	221.83 m		
	Min Storage Limits	69.3 ksfd	169.5 hm^3	Jul - Aug 31	
		710.8 ft	216.65 m		
		65.6 ksfd	160.5 hm^3	Sep - Oct	
		708.8 ft	216.04 m		
		16.6 ksfd	40.6 hm^3	Nov - Mar	
		677.8 ft	206.59 m		
		38.0 ksfd	93.0 hm^3	Apr 15 - Apr 30	
		693.8 ft	211.47 m		
		69.3 ksfd	169.5 hm^3	May - Jun	
		710.8 ft	216.65 m		

Appendix A
Project Operating Procedures for the 2014-15
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Timothy (117)	Minimum Content	24.5 ksfd 3180.0 ft	59.9 hm^3 969.26 m	Oct - May	3-6-01 PNCA submittal
		31.1 ksfd 3190.0 ft	76.1 hm^3 972.31 m	Jun - Aug 31	
		27.8 ksfd 3185.0 ft	68.0 hm^3 970.79 m	Sep	
Long Lake (1305)	Minimum Content	50.1 ksfd 1535.0 ft	122.6 hm^3 467.87 m	Apr - Nov	2-5-02 PNCA submittal
		19.7 ksfd 1522.0 ft	48.2 hm^3 463.9 m	Dec - Mar	
	Draft Rate Limit	1.0 ft/day	0.30 m/day		2-1-03 PNCA submittal
Priest Lake (1470)	Maximum Content	0.0 ksfd 0.0 ft	0.0 hm^3 0.00 m	Oct	2-1-03 PNCA submittal
	Max/Min Content	35.5 ksfd 3.0 ft	86.9 hm^3 0.91 m	Maintain at or near after runoff through Sep.	
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries.	2-1-06 PNCA submittal
		Fixed ARC's			2-1-09 PNCA submittal
Gorge (2065)	Minimum Flow			Settlement; monthly data, varies by water year.	2-1-06 PNCA submittal

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2014-15

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TABLE OF CONTENTS

Section **Page**

1. Introduction ... 1
2. Procedures ... 1
3. Results of Canadian Entitlement Computations ... 3
4. Computation of Maximum Allowable Reduction in Downstream Power Benefits ... 3
5. Delivery of the Canadian Entitlement ... 3
6. Summary of Information Used for Canadian Entitlement Computations ... 3
7. Summary of Changes Compared to the 2013-14 DDPB and Notable Assumptions ... 5
    a) Steps II and III Firm Loads ... 5
    b) Thermal Installations ... 6
    c) Hydro Project Modified Stream Flows ... 6
    d) Hydro Project Rule Curves ... 7
    e) Other Hydro Project Operating Procedures, Constraints, and Plant Data ... 7
    f) Steps II and III Critical Period and 30-year System Regulation Studies ... 7
    g) Downstream Power Benefits ... 7

TABLE 1A DETERMINATION OF STEP I FIRM ENERGY HYDRO LOADS ... 9
TABLE 1B DETERMINATION OF STEP I FIRM PEAK HYDRO LOADS ... 10
TABLE 2 DETERMINATION OF THERMAL DISPLACEMENT MARKET ... 11
TABLE 3 DETERMINATION OF LOADS FOR STEP II AND STEP III STUDIES ... 12
TABLE 4 SUMMARY OF STEPS I, II, & III POWER REGULATIONS ... 13
TABLE 5 COMPUTATION OF CANADIAN ENTITLEMENT ... 14
TABLE 6 COMPARISON OF RECENT DDPB STUDIES ... 15
CHART 1 DURATION CURVES OF 30-YEAR MONTHLY HYDRO GENERATION ... 17

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2014-15

September 2010

1. Introduction

The "Treaty between Canada and The United States of America relating to Cooperative Development of The Water Resources of The Columbia River Basin" (Treaty), dated 17 January 1961, requires that downstream power benefits from the operation of the Treaty storage in Canada (Canadian Treaty Storage) to be determined in advance by the two Entities created by the Treaty. The purpose of this document is to describe the results of the Determination of Downstream Power Benefits for operating year 2014-15 (DDPB15).

2. Procedures

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

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

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

- Except for the changes noted below, the "Columbia River Treaty Entity Agreement on the Principles and Procedures for Preparing and Implementing Hydroelectric Operating Plans For Operation of Canadian Treaty Storage" (POP), dated October 2003 and signed 16 December 2003, including the update to Appendix 1, dated 18 November 2003, the November 2004 addition of Appendix 6, Streamline Procedures, and Appendix 7, Table of Median Streamflows, and the 25 September 2007 addition of Appendix 8 concerning Water Supply Forecasts.

Special terms used in this document, but not defined herein, have the meanings defined in the Treaty, Protocol, or the above Entity Agreements. The POP is based on criteria contained in Annex A and Annex B of the Treaty, the Protocol, and the "Columbia River

Treaty Flood Control Operating Plan" (FCOP) dated May 2003. For this DDPB, the Entities have agreed to use only the first of the three streamline methods defined in Appendix 6 of the POP, which is "Forecasting Loads and Resources," for determining the thermal installations, and is described in Subsection 7(d) of the AOP15.

In addition, the Entities have agreed to the following modifications to the DDPB study procedures:

- Allocate available uncommitted Pacific Northwest Area (PNWA) resources and available uncommitted imports from Canada and California, together with a seasonal exchange, to balance the White Book (WB) deficit, as was done in the AOP/DDPB14 studies and is described in Subsection 7(b) of the AOP15;

- Modify the DDPB15 Table 2 calculation of Thermal Displacement Market, as was done in the DDPB14, to use thermal imports (e.g. market purchases of power from California, but not Canadian Entitlement (CE) or Skagit Treaty power) to support exports (not including CE, plant sales, flow-through-transfers (FTT), seasonal exchanges (SE) or excess extra-regional thermal installations), on an annual basis, as either FTTs or SEs.

The Canadian Entitlement Benefits were computed from the following studies:

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

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

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

As part of the DDPB, separate determinations may be carried out relating to the limit of year-to-year reduction in benefits attributable to the operation of Canadian Treaty Storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the USA (Joint Optimum). However, as indicated in Section 4 below, the calculations were not needed for the 2014-15 operating year.

3. Results of Canadian Entitlement Computations

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

Dependable Capacity	= 1368.6 megawatts (MW)
Average Annual Usable Energy	= 479.9 average annual MW

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

4. Computation of Maximum Allowable Reduction in Downstream Power Benefits

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

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

Step II studies based on the assumption of optimum power generation in Canada and the USA resulted in a 10.0 average annual megawatt (aMW) increase in the Energy Entitlement and a 1.5 MW increase in the Capacity Entitlement (see Table 5, columns A and B), compared to the Step II study based on optimum power generation only in the USA. 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 AOP15.

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 show the loads and resources used in the Step I studies and the computation of the coordinated hydro load for the Step I hydroregulation study. 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. 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.

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) Draft 2009 White Book (WB09) load forecast as described in Subsection 7(a) of the AOP15. The Grand Coulee 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 and 3. The hydro maintenance is summed with transmission losses and reserves in the Step I system load as an adjustment to resources.

This table has been modified from the DDPB14 version to calculate the Step II and III System's firm peak capability based on different years than used in prior DDPB studies, which was January 1944 for Step II and January 1937 for Step III. The DDPB15 Table 4 calculation of firm peak capability for both Steps II and III is based on January 1950, since 1950 has the least surplus firm peak capability over the thirty water years..

Table 5 Computation of Canadian Entitlement

A. Joint Optimum Generation in Canada and the USA
B. Optimum Generation in the USA Only
C. Optimum Generation in the USA and a 0.62 km^3 (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 USA Optimum are shown under Columns A and B respectively. These elements for the computation of maximum allowable reduction in downstream power benefits are shown in column C.

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 USA Optimum Steps II and III system regulation studies[2] which graphically illustrate the change in average annual usable hydro energy. Usable hydro energy consists of firm energy plus usable nonfirm energy. Firm energy is the firm hydro loads shown in Table 3, 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 2013-14 DDPB and Notable Assumptions

Data from recent DDPBs are summarized in Table 6. The following is an explanation of changes and notable assumptions that impact computation of the entitlement compared to the 2013-14 DDPB (DDPB14) studies.

a) Steps II and III Firm Loads

The Steps II and III hydro firm loads shown on Table 3 are noticeably different from the DDPB14. For DDPB15, loads are substantially lower in March and higher in June and July, as shown in the table below. This is mainly due to the change in PNWA load shape and thermal maintenance schedules, which are explained in Subsection 7(b).

Differences between DDPB15 and DDPB14 Table 3 Hydro Loads

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	June	July	Avg.	CPavg
DDPB15 S2	7940	7801	6666	6902	8861	10491	10782	9937	9270	8138	8721	10343	8936	9047	8961	8945
DDPB14 S2	7817	7815	6666	6838	8710	10399	10822	9980	10009	8346	8587	10379	8379	8299	8897	8935
Difference	123	-14	0	64	151	92	-40	-43	-739	-208	134	-36	557	748	64	10
DDPB15 S3	5343	5207	4224	4453	6125	7522	7779	7051	6618	5631	6208	7898	6380	6349	6300	6899
DDPB14 S3	5160	5158	4169	4321	5918	7362	7723	7006	7255	5745	5983	7859	5790	5582	6168	6942
Difference	184	49	56	132	207	160	57	45	-636	-114	225	39	590	767	132	-44

The average critical period load factor increased slightly from 74.60% in AOP14 (Draft WB08) to 74.76% in AOP15 (Draft WB09).

b) Thermal Installations

The total Thermal Installation energy capability shown in Table 3 increased by 86.5 annual aMW compared to the DDPB14. This is due mainly to a 211 aMW increase in the PNWA firm load, a 62 aMW decrease in the net exports and imports, a 72 aMW increase in the Step I renewable resources (mostly wind), and changes in the thermal maintenance schedules.

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

In addition, the thermal maintenance schedules for other large projects (mostly coal but also combustion turbines and co-generation) changed resulting in a large increase (about 6% compared to annual average) in March thermal generation and a decrease in April 1-15, June, and July generation (about 2% for each period).

The Thermal Displacement Market (TDM) increased by 131 annual aMW, due to a combination of the changes in Thermal Installations and System Sales. Both the Thermal Installation and TDM changes are shown in the following table.

DDPB15 minus DDPB14 Table 2 Thermal Installations and Thermal Displacement Market

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	June	July	Avg.	CPavg
Ddpb15 T.I.	10675	10798	10841	10658	10754	10796	10745	10752	9744	9833	9297	7191	9388	10299	10117	10216
Ddpb14 T.I.	10613	10612	10654	10618	10654	10663	10676	10650	9099	9695	9473	7102	9575	10550	10031	10125
Difference	62	185	186	40	100	133	69	102	644	138	-176	89	-188	-251	86	90
TDM 15	10255	10374	10416	10237	10331	10372	10323	10330	9346	9433	8911	6850	8986	9884	9709	9805
TDM 14	10147	10147	10188	10152	10188	10196	10209	10184	8671	9252	9036	6715	9123	10085	9578	9670
Difference	107	227	228	85	144	176	114	146	675	182	-125	135	-137	-201	131	135

c) Hydro Project Modified Stream Flows

The base unregulated stream flows used in the Steps II and III System Regulation Studies are the same as the Step I studies (see Subsection 7(e) of AOP15), except for adjustments to add the effect of natural lake regulation and remove reservoir evaporation at projects not included in Steps II/III. The annual shape of irrigation pumping flows as Grand Coulee changed from AOP14 to AOP15, although the annual volume increased by only 0.16 kcfs. Pumping flows were especially higher in April 16 through July and September, which affects the Step II critical period study but not the Step 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 AOP15. 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 AOP15.

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

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 2014-15 operating year in accordance with procedures described in Section 3.3 of the POP. The System Regulation studies used version 28 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 and Step III critical stream flow periods were unchanged from the DDPB14 studies. The Step II critical period comprised the 20 calendar-months from 1 September 1943 through 30 April 1945, and the Step III critical period included the 5.5 calendar-months from 1 November 1936 through 15 April 1937. The Step II critical period generation, compared to DDPB14, increased by only 10.2 aMW, but the average annual firm energy increased by 63.9 aMW. The difference is mainly due to a 557 and 748 aMW increase in the June-July hydro loads respectively, because there is only one June-July period during the two year critical period, which increases the annual average twice as much as the critical period average. The Step III critical period generation decreased by 43.6 aMW due to an increase in hydro load during the winter months and a 636 aMW decrease in the March hydro load, causing additional winter draft, spill, and loss of head. The average annual firm energy increased by 131.7 aMW, again due to the increase in June-July hydro loads that are not in the critical period. The change in March hydro load is caused mainly by changes to thermal maintenance, and the change in June-July hydro loads is caused by a change in the PNWA firm load shape.

The Step II 30-year average generation, compared to DDPB14, increased by 2 aMW, and the Step III 30-year average generation increased by 11 aMW, both due mainly to changes in storage operations caused by changes in the hydro load shape.

g) Downstream Power Benefits

The Canadian Capacity Entitlement increased from 1335.5 MW in the DDPB14 to 1368.6 MW in the DDPB15, an increase of 33.1 MW. This is mainly due to the complementary changes in critical period generation, i.e. Step II increased and Step III decreased, making the Step II minus Step III difference larger.

The Canadian Energy Entitlement decreased from 505.5 annual aMW in the DDPB14 to 479.9 annual aMW in the DDPB15, a decrease of 25.6 annual aMW. This decrease is caused by the additional thermal resources and changes in load shape and thermal maintenance schedules, which increases the Step II usable energy by 11.5 aMW, and also increases the Step III usable energy by 58.8 aMW, making the Step II minus Step III difference smaller.

End Notes:

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

[2] The Step II DDPB15-42 30 year system regulation study dated July 29, 2010 and the Step III DDPB15-13 30-year system regulation study dated January 29, 2010 were used to determine the critical period and 30-year system generation.

TABLE 1A
DETERMINATION OF STEP I FIRM ENERGY HYDRO LOADS
FOR 2014-15 ASSURED OPERATING PLAN
(Average MW)

	Aug15	Aug31	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	Jun	Jul	Ann. Avg.	CP Avg. 1/
1. Pacific Northwest Area (PNWA) Firm Load																
a) White Book Regional Firm Load 2/	22935	22935	21551	21637	24112	26168	26487	25496	23376	22109	22109	21614	22633	23900	23495	23593
b) Exclude 99% of UPL's Idaho load 3/	-489	-489	-455	-454	-454	-487	-457	-471	-440	-416	-416	-465	-539	-595	-477	-475
c) Update Coulee pumping 4/	9	-11	21	-1	2	-3	-62	-68	0	-16	42	3	8	32	-4	-6
d) …Total PNWA Firm Loads	**22455**	**22435**	**21118**	**21182**	**23661**	**25678**	**25968**	**24957**	**22936**	**21677**	**21734**	**21151**	**22103**	**23336**	**23014**	**23112**
e) Annual Load Shape in Percent	97.6	97.5	91.8	92.0	102.8	111.6	112.8	108.4	99.7	94.2	94.4	91.9	96.0	101.4	100.0	100.4
2. Flows-Out of firm power from PNWA																
a) White Book Exports 5/	1102	1101	1056	838	788	829	725	720	754	754	746	677	903	995	845	846
b) Remove WB Canadian Entitlement	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483
c) Add est. Can. Entitle. Exported 6/	483	483	483	483	483	483	483	483	483	483	483	483	483	483	483	483
d) Added SeEx for WB Surplus	0	0	0	0	0	0	0	0	0	0	0	0	1132	0	93	79
e) Added SeEx for AOP Hydro 7/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Imp. Thermal used out of region 8/	231	264	238	150	101	8	47	92	119	132	91	104	164	179	130	128
g) …Subtotal for Table 2	1333	1366	1294	988	889	837	772	811	873	886	837	780	2198	1173	1068	1053
h) Remove Plant Sales	-175	-176	-183	-185	-189	-184	-181	-176	-211	-182	-174	-57	-195	-188	-175	-176
i) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60	-59
j) …Total	**1083**	**1115**	**1036**	**758**	**655**	**608**	**547**	**591**	**617**	**629**	**588**	**648**	**1928**	**910**	**833**	**818**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations																
a) White Book Imports 9/	-732	-704	-698	-751	-1013	-1191	-1073	-1026	-819	-756	-752	-710	-825	-886	-871	-882
b) Remove UP&L imports for 1(b)	494	494	459	459	458	492	461	476	445	420	420	470	544	602	482	480
c) Remove Eastern Thermal Instal 10/	129	100	128	209	262	356	315	271	206	197	218	136	167	172	212	217
d) Added SeEx for WB Surplus	0	0	0	0	0	0	-900	-216	0	0	0	0	0	0	-93	-105
e) Added Can.Import for WB deficits 11/	-256	-256	-256	-256	-256	-256	-256	-256	-256	-256	-256	-256	-256	-256	-256	-256
f) Added Calif.Import for WB deficits12/	**0**	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Added Seas.Exch. for Aop hydro 7/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	45	45	75	75	75	75	75	60	59
i) …Total	**-291**	**-292**	**-292**	**-293**	**-505**	**-554**	**-1408**	**-706**	**-380**	**-321**	**-295**	**-284**	**-295**	**-294**	**-467**	**-487**
4. PNWA Non-Step I Hydro and Non-Thermal Resources																
a) Hydro Independents (1929 water)	-1013	-1006	-995	-1041	-1126	-1064	-1026	-854	-970	-1147	-1164	-1431	-1378	-1124	-1099	-974
b) Non-Step I Coordinated Hydro(1929)	-512	-427	-570	-940	-912	-957	-1271	-673	-714	-718	-735	-625	-1054	-662	-798	-812
c) WB Regional Hydro NUGs	-310	-309	-231	-154	-114	-105	-96	-101	-133	-260	-269	-392	-424	-406	-228	-216
d) WB Renewable NUGs	-45	-45	-45	-45	-53	-53	-53	-53	-53	-53	-45	-45	-45	-45	-49	-49
e) WB Renewables	-702	-810	-619	-611	-624	-610	-601	-612	-914	-844	-868	-884	-977	-849	-744	-726
f) …Total (1929)	**-2583**	**-2597**	**-2461**	**-2791**	**-2829**	**-2789**	**-3048**	**-2294**	**-2783**	**-3023**	**-3082**	**-3378**	**-3878**	**-3086**	**-2919**	**-2777**
5. Step I System Load (1929) 13/	**20664**	**20662**	**19401**	**18856**	**20982**	**22942**	**22059**	**22547**	**20390**	**18963**	**18945**	**18136**	**19858**	**20867**	**20462**	**20665**
6. Coordinated Thermal Installations 14/																
a) Columbia Generation Station (WNP2)	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	764	515	897	954	965
b) Generic Thermal Installations	9645	9768	9811	9628	9724	9766	9715	9722	8714	8803	8267	6427	8873	9402	9163	9250
c) ...Total	**10675**	**10798**	**10841**	**10658**	**10754**	**10796**	**10745**	**10752**	**9744**	**9833**	**9297**	**7191**	**9388**	**10299**	**10117**	**10216**
7. Step I Hydro Resources (1929) 15/	**10675**	**10545**	**9186**	**8818**	**10910**	**12879**	**12052**	**12506**	**11308**	**9759**	**10277**	**11573**	**11154**	**11292**	**11021**	**11127**
8. Step I Resource Adjustments																
a) Hydro Maintenance	-30	-25	-9	-9	-4	0	0	0	-5	-7	-8	-20	-14	-49	-12	-11
b) Transmission System Losses 16/	-656	-656	-617	-611	-677	-732	-739	-712	-656	-621	-622	-607	-669	-675	-664	-667
9. Total Step I System Resources(1929)	**20664**	**20662**	**19401**	**18856**	**20982**	**22942**	**22059**	**22547**	**20390**	**18963**	**18945**	**18136**	**19858**	**20867**	**20462**	**20665**
10. Coordinated Hydro Load (1929) 17/	**11187**	**10971**	**9756**	**9758**	**11821**	**13836**	**13323**	**13179**	**12022**	**10476**	**11012**	**12198**	**12208**	**11954**	**11819**	**11939**
a) Coord. Hydro Load Shape (1929)	94.6%	92.8%	82.5%	82.6%	100.0%	117.1%	112.7%	111.5%	101.7%	88.6%	93.2%	103.2%	103.3%	101.1%	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 Draft 2009 White Book (WB09) total regional firm load estimate on April 13, 2009, which includes estimated Coulee pumping and Idaho loads served by Utah P&L.
3/ Annex B requires exclusion of Idaho load (and corresponding import) from area served by Utah Power Light in 1964.
4/ Although a minor change, Coulee pumping loads were updated to the 2009 PNCA data submittal to be consistent with the pumping flows in the Base Flows.
5/ WB09 exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and an estimate of the Canadian Entitlement.
6/ Assumes 483 MW Energy Entitlement exported to Canada.
7/ Seasonal Exchanges for reshaping Hydro load were not employed in this AOP, but line 2. e) was retained for continuity.
8/ Added thermal export to balance difference between thermal import and equivalent thermal installation based on generic annual shape.
9/ White Book Imports include coordinated thermal installations, seasonal & capacity exchanges, flow-through-transfers, and Skagit Treaty power.
10/ Imports identified as coordinated thermal installations are excluded, to be replaced by a portion of the Generic Thermal Installations.
11/ Added Canadian import as a portion of the resources needed to balance WB deficits, based on 53% of estimated 483 aMW of Energy Entitlement .
12/ Added Calif. import as a portion of the resources needed to balance WB deficits, based on the proata procedure.
13/ Line 1(d) + line 2(i) + line 3(g) + line 4(f), based on 1929 hydro independent capability.
14/ Thermal installations are CGS, plus a generic thermal installation that is sized to meet the Step 1 System load minus Step I Hydro.
15/ Step I Hydro (US hydro projects at and upstream of Bonneville Dam) critical period capability shaped to 1929 load, line 5 minus line 6(c), 8(a), & 8(b).
16/ Transmission losses are 2.71% of all resources including imports.
17/ The Coordinated Hydro Model Load is the Step I Hydro Resources plus Non-Step I Coordinated Hydro, lines 7 - 4(b).
18/ The Coordination 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 FOR 2014-15 ASSURED OPERATING PLAN (MW)

Based on 1932 water year which has minimum peak surplus

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. Pacific Northwest Area (PNWA) Firm Load														
a) White Book Regional Firm Load	29861	29861	27848	29118	32777	35190	35695	34004	31042	29080	29080	28597	29723	31206
b) Exclude 99% of UPL's Idaho load	-532	-532	-489	-489	-495	-518	-489	-502	-467	-443	-443	-515	-618	-653
c) Adj.for Federal Peak Diversity 1/	-162	-176	-202	-120	-120	-205	-125	-129	-153	-166	-171	-169	-160	-136
d) Updates to Coulee pumping forec.	289	257	296	429	249	357	185	248	302	199	219	258	270	270
e) ….Total PNWA Firm Loads	**29456**	**29409**	**27452**	**28938**	**32411**	**34825**	**35267**	**33621**	**30724**	**28670**	**28684**	**28171**	**29216**	**30688**
f) Monthly Load Factors in Percent	76.23	76.29	76.93	73.20	73.00	73.74	73.63	74.23	74.65	75.61	75.77	75.08	75.65	76.05
2. Flows-Out of firm power from PNWA														
a) White Book Exports	2216	2217	2222	1848	1728	1724	1619	1615	1649	1649	1649	1611	2120	2114
b) Remove WB Canadian Entitlement	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350
c) Add estimated Can.Entitle. exported	1333	1333	1333	1333	1333	1333	1333	1333	1333	1333	1333	1333	1333	1333
d) Add Seasonal Exch. WB Export	0	0	0	0	0	0	0	0	0	0	0	0	1132	0
e) Add Seasonal Exch. Shape Export	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Thermal Inst. used outside region 2/	267	303	277	208	115	0	52	94	151	174	121	127	154	231
g) …Subtotal for Table 2	*2466*	*2503*	*2482*	*2039*	*1826*	*1707*	*1653*	*1692*	*1784*	*1806*	*1753*	*1721*	*3388*	*2328*
h) Remove Plant Sales	-185	-185	-192	-194	-198	-193	-190	-185	-220	-191	-191	-57	-205	-197
i) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75
j) …Total	**2206**	**2242**	**2214**	**1800**	**1582**	**1468**	**1418**	**1462**	**1518**	**1540**	**1487**	**1589**	**3108**	**2055**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations														
a) White Book Imports	-951	-915	-899	-942	-1325	-1507	-1456	-1459	-1051	-928	-944	-945	-1112	-1108
b) Remove UP&L imports for	538	538	494	494	500	523	494	507	472	447	447	520	624	660
c) Remove Eastern Thermal Instal	192	156	184	256	353	469	418	374	278	247	263	203	267	228
d) Added SeEx for WB Surplus	0	0	0	0	0	0	-900	-216	0	0	0	0	0	0
e) Added Can.Import for WB deficits	-706	-706	-706	-706	-706	-706	-706	-706	-706	-706	-706	-706	-706	-706
f) Added Calif.Import for WB deficits	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Added Seas.Exch. for Aop hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	45	45	75	75	75	75	75
g) …Total	**-853**	**-853**	**-853**	**-854**	**-1133**	**-1176**	**-2106**	**-1456**	**-963**	**-866**	**-866**	**-853**	**-853**	**-853**
4. PNWA Non-Step I Hydro and Non-thermal Resources														
a) Hydro Independents (1932)	-1559	-1545	-1576	-1337	-1591	-1504	-1569	-1396	-1781	-1760	-1803	-1957	-1995	-1738
b) Non-Step I Coord. Hydro (1932)	-1821	-1980	-2006	-2075	-2142	-2114	-2019	-1867	-1817	-1674	-1785	-1960	-2337	-2430
c) WB Regional Hydro NUGs	-360	-358	-287	-205	-147	-135	-128	-138	-173	-287	-296	-420	-436	-429
d) WB Renewable NUGs	-119	-119	-119	-119	-119	-119	-119	-119	-119	-119	-119	-119	-119	-119
e) WB Renewables	-152	-152	-152	-152	-152	-152	-152	-152	-152	-152	-152	-152	-152	-152
f) …. Total (1932)	**-4011**	**-4153**	**-4140**	**-3888**	**-4150**	**-4023**	**-3987**	**-3672**	**-4042**	**-3991**	**-4155**	**-4608**	**-5039**	**-4868**
5. Step I System Load 3/ (1932)	**26798**	**26645**	**24674**	**25997**	**28710**	**31093**	**30591**	**29955**	**27237**	**25353**	**25150**	**24299**	**26433**	**27022**
6. Coordinated Thermal Installations														
a) Columbia Generating Station (cgs)	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	575	575	1150
b) Generic Thermal Installations	12297	12297	12353	12461	12540	12578	12585	12561	11511	11282	10288	8847	11282	12300
c) ...Total	**13447**	**13447**	**13503**	**13611**	**13690**	**13728**	**13735**	**13711**	**12661**	**12432**	**11438**	**9422**	**11857**	**13450**
7. Step I Hydro Resc. Needed (1932) 4/	**23821**	**23221**	**20916**	**21629**	**24217**	**25822**	**24910**	**24609**	**22877**	**21306**	**21805**	**22798**	**22942**	**23487**
8. Step I Resource Adjustments														
a) Hydro Maintenance 5/	-4595	-4032	-3787	-3208	-2935	-2037	-1561	-2286	-2626	-2751	-2483	-2360	-2202	-3720
b) Transmission System Losses 6/	-1060	-1060	-993	-1029	-1138	-1215	-1228	-1175	-1080	-1012	-1010	-996	-1082	-1096
c) Reserves 7/	-4815	-4931	-4965	-5006	-5124	-5205	-5264	-4904	-4596	-4622	-4600	-4565	-5083	-5099
d) Total maint., losses, & reserves	-10470	-10023	-9746	-9244	-9197	-8457	-8053	-8364	-8301	-8384	-8093	-7921	-8367	-9915
e) Hydro maint. as %reg. hydro cap.=	15.3%	13.3%	12.4%	10.6%	9.6%	6.7%	5.3%	8.2%	9.8%	10.0%	8.9%	8.1%	7.2%	12.0%
f) Peak Reserves as % resources	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
9. Required Step I Resources	**26798**	**26645**	**24674**	**25997**	**28710**	**31093**	**30591**	**29955**	**27237**	**25353**	**25150**	**24299**	**26433**	**27022**
10. Coordinated Hydro load and Surplus/Deficit (1932)														
a) Coordinated Hydro Load (1932) 8/	25642	25201	22922	23704	26358	27935	26929	26476	24695	22980	23590	24758	25280	25917
b) Actual Coord. Hydro Gen (1932) 9/	30058	30409	30431	30364	30544	30423	29585	28030	26737	27479	27838	28973	30661	30900
c) ...Surplus/Deficit (1932)	4416	5208	7509	6660	4186	2488	2656	1554	2042	4499	4248	4215	5381	4983

Notes:

1/ Federal peak diversity is a reduction in peak load due to peak loads not all being coincidental. Used % WB09 of (~1.8%) x PNWA load.
2/ Export or import to balance difference between excluded thermal imports and generic thermal installation.
3/ Total Step I Firm Peak Load is the sum of lines 1e + 2j + 3g + 4f
4/ Step I hydro resources needed to meet the load = line 5 minus lines 6c and 8d. Actual resource capability is higher. Used 1932 because has lowest surplus.
5/ From WB, based on 5-year PNCA average as a MW reduction from installed capacity. May need to revise next year as a reduction from 1937 capability.
6/ Transmission losses are 3.2% of all resources including imports, net of reserves and maintenance.
7/ Reserves are 11% of peak resources.
8/ Lines 4b and 7
9/ System Instantaneous Peak Capability (1932). This value does not include an operational (sustained) peaking adjustment similar to WB09. Future studies will examine whether it is appropriate to include that adjustment.

TABLE 2
DETERMINATION OF THERMAL DISPLACEMENT MARKET
FOR 2014-15 AOP/DDPB STEPS II AND III STUDIES
(Average MW)

	Aug15	Aug31	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	Jun	Jul	Annual Average	CP Avg (42.5 mon)
1. STEP I THERMAL INSTALLATIONS																
a) From Table 1A, line 6(c)	10675	10798	10841	10658	10754	10796	10745	10752	9744	9833	9297	7191	9388	10299	10117.2	10215.7
2. DISPLACEABLE THERMAL RESOURCES																
a) Minimum Gen. from % of Thermal	240	243	244	240	242	243	242	242	217	219	206	160	221	234	228.2	230.3
b) Net Displaceable Thermal Resources	**10435**	**10554**	**10596**	**10418**	**10512**	**10553**	**10503**	**10510**	**9527**	**9614**	**9091**	**7031**	**9167**	**10065**	**9889.0**	**9985.3**
3. SYSTEM SALES (i.e. Amount of Coordinated Thermal Installation Power Used Outside PNWA)																
a) Flows-Out (Table 1A, line 2(g))	1333	1366	1294	988	889	837	772	811	873	886	837	780	2198	1173	1068.4	1052.8
b) ...Exclude Canadian Entitlem.Exported	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483	-483.0	-483.0
c) ...Exclude Plant Sales	-175	-176	-183	-185	-189	-184	-181	-176	-211	-182	-174	-57	-195	-188	-175.0	-176.1
d) ...Exclude WB Flow-Through-Transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60.0	-58.8
e) ...Exclude WB. Seasonal Exchange	-219	-217	-210	-26	-3	-3	-3	-3	-3	-3	-3	0	-84	-200	-63.2	-61.9
f) ...Exclude SeEx for WB Surp/Def	0	0	0	0	0	0	0	0	0	0	0	0	-1132	0	-93.0	-78.8
g) ...Exclude SeEx for AOP Hydro Diff.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0
h) ...Exclude Other Flow-Through-Transfer	-12	-13	-18	-14	-21	-20	-21	-21	-20	-18	-2	0	0	-8	-13.7	-14.4
i) ...Exclude Other Seasonal Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0
j) ...Total System Sales	369	402	325	236	148	102	40	84	112	126	100	165	228	219	180.5	179.7
k) Uniform Average Annual System Sales	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180.5	180.5
4 THERMAL DISPLACE. MARKET	**10255**	**10374**	**10416**	**10237**	**10331**	**10372**	**10323**	**10330**	**9346**	**9433**	**8911**	**6850**	**8986**	**9884**	**9708.5**	**9804.9**

Notes:

2a Minimum generation is 0.0249 times the monthly average Step 1 thermal, without CGS; based on 2006 AOP data.
3b Canadian Entitlement exports are assumed to be supported by hydro instead of thermal.
3c Plant sales include Longview Fibre and approximately 25 percent of Boardman; line 2(h), 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 for reshaping Hydro load were not employed in this AOP, but line 3 g) was retained for continuity.
3h Other flow through transfers are remaining flows-out supported by remaining thermal imports in the same period.
3i Other Season Exchanges remaining exports supported by thermal imports greater than imports on an annual basis
3j Total System Sales are total exports excluding exchanges, plant sales, flow-thru-xfers, and the Canadian Entitlement. The sum of Lines 3(a) through 3(i).
3k Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.
4 PNW Area Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNW Area firm loads. Lines 2(b) minus 3(k).

TABLE 3
DETERMINATION OF LOADS FOR STEP II AND STEP III STUDIES
FOR 2014-15 AOP/DDPB STUDIES

	PACIFIC NORTHWEST AREA LOADS				THERMAL INSTALLATIONS			
Period	Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Energy Capability 2/ aMW	Annual Energy Shape Percent	Peak Capability MW	Capacity Factor Percent
August 1-15	22455	97.57	29456	76.23	10675	105.5%	13447	79.4%
August 16-31	22435	97.49	29409	76.29	10798	106.7%	13447	80.3%
September	21118	91.76	27452	76.93	10841	107.2%	13503	80.3%
October	21182	92.04	28938	73.20	10658	105.3%	13611	78.3%
November	23661	102.81	32411	73.00	10754	106.3%	13690	78.6%
December	25678	111.58	34825	73.74	10796	106.7%	13728	78.6%
January	25968	112.84	35267	73.63	10745	106.2%	13735	78.2%
February	24957	108.44	33621	74.23	10752	106.3%	13711	78.4%
March	22936	99.66	30724	74.65	9744	96.3%	12661	77.0%
April 1-15	21677	94.19	28670	75.61	9833	97.2%	12432	79.1%
April 16-30	21734	94.44	28684	75.77	9297	91.9%	11438	81.3%
May	21151	91.91	28171	75.08	7191	71.1%	9422	76.3%
June	22103	96.04	29216	75.65	9388	92.8%	11857	79.2%
July	23336	101.40	30688	76.05	10299	101.8%	13450	76.6%
Annual Avg. 7/	23013.7	100.00		74.84	10117.2	100.0%		78.4%
SI CP Avg(42.5mon)	23111.9			**74.76**	10215.7			
S2 CP Avg(20mon)	23169.3				10262.5			
S3 CP Avg(5.5mon)	24372.4	AvgAnnEn/JanPk=		65.3%	10488.0	AvgAnnEn/JanPk=		73.7%

	STEP II SYSTEM				STEP III SYSTEM			
Period	Total Energy Load 3/ aMW	Total Peak Load MW	Hydro Energy Load 4/ aMW	Hydro Peak Load MW	Total Energy Load 3/ aMW	Total Peak Load MW	Hydro Energy Load 4/ aMW	Hydro Peak Load MW
August 1-15	18614.9	24419	7939.8	10972	16018.6	21013	5343.5	7566
August 16-31	18598.6	24380	7800.9	10933	16004.6	20980	5206.8	7532
September	17506.8	22758	6666.2	9254	15065.0	19584	4224.4	6080
October	17559.8	23990	6902.2	10379	15110.7	20644	4453.0	7033
November	19614.9	26868	8860.9	13179	16879.1	23121	6125.2	9431
December	21287.0	28870	10491.1	15141	18318.0	24843	7522.1	11115
January	21527.1	29236	10781.9	15501	18524.6	25158	7779.4	11424
February	20689.2	27872	9937.1	14161	17803.6	23985	7051.4	10274
March	19014.1	25471	9270.4	12809	16362.1	21918	6618.5	9257
April 1-15	17970.5	23768	8137.5	11336	15464.0	20453	5631.1	8021
April 16-30	18017.8	23779	8720.6	12341	15504.8	20463	6207.6	9025
May	17534.2	23354	10343.3	13932	15088.6	20097	7897.8	10674
June	18323.3	24220	8935.8	12363	15767.7	20842	6380.2	8985
July	19345.9	25440	9047.2	11990	16647.7	21892	6348.9	8442
Annual Avg. 7/	19078.3		8961.2		16417.4		6300.2	
S2 CP Avg(20mon)	19207.4		8944.9					
S3 CP Avg(5.5mon)					17386.6		6898.7	
Joint Optimum S2 CP capability 5/ =			**8944.90**		S3 CP capability 6/ =		**6898.68**	

Notes:

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

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

3/ The total firm load for the Step II/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 water years.

TABLE 4
SUMMARY OF STEPS I, II, & III POWER REGULATIONS
FOR 2014-15 ASSURED OPERATING PLAN

	BASIC DATA		STEP I				STEP II					STEP III				
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	USABLE STORAGE hm^3	CRITICAL CAPACITY FPLCC Jan.1932 MW	CRITICAL ENERGY FELCC Avg.Gen MW	USABLE STORAGE kaf	USABLE STORAGE hm^3	CRITICAL CAPACITY FPLCC Jan.1950 MW	CRITICAL PERIOD FELCC Avg.Gen MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	USABLE STORAGE hm^3	CRITICAL CAPACITY FPLCC Jan.1950 MW	CRITICAL PERIOD FELCC Avg.Gen MW	30 YEAR AVERAGE ANNUAL GEN. MW
1. HYDRO RESOURCES																
a) CANADIAN STORAGE																
Mica			7000	8634			7000	8634								
Arrow			7100	8758			7100	8758								
Duncan			1400	1727			1400	1727								
Subtotal			15500	19119			15500	19119								
b) BASE SYSTEM																
Hungry Horse	4	428	3072	3789	154	101	3008	3710	337	116	104	3008	3710	339	192	102
Kerr	3	160	1219	1504	166	123	1219	1504	178	112	129	1219	1504	180	160	123
Thompson Falls	6	85	0	0	85	56	0	0	85	53	58	0	0	85	66	57
Noxon Rapids	5	554	231	285	490	147	0	0	528	128	194	0	0	528	173	195
Cabinet Gorge	4	239	0	0	238	98	0	0	238	86	118	0	0	238	113	119
Albeni Falls	3	50	1155	1425	22	23	1155	1425	17	22	21	1155	1425	16	15	19
Box Canyon	4	74	0	0	72	46	0	0	70	45	48	0	0	70	56	47
Grand Coulee	24+3SS	6684	5185	6396	5831	2059	5072	6256	6365	1849	2412	5072	6256	5482	1210	2304
Chief Joseph	27	2535	0	0	2535	1063	0	0	2535	965	1301	0	0	2535	700	1232
Wells	10	840	0	0	840	419	0	0	840	387	487	0	0	840	287	442
Chelan	2	54	677	835	50	38	676	834	52	38	46	676	834	53	45	43
Rocky Reach	11	1267	0	0	1267	571	0	0	1267	528	690	0	0	1267	384	642
Rock Island	18	513	0	0	547	262	0	0	547	245	313	0	0	547	182	289
Wanapum	10	986	0	0	825	500	0	0	825	464	585	0	0	825	328	520
Priest Rapids	10	912	0	0	770	487	0	0	770	454	557	0	0	770	329	492
Brownlee	5	675	975	1203	675	243	974	1201	675	301	319	974	1201	675	260	319
Oxbow	4	220	0	0	220	101	0	0	220	126	130	0	0	220	116	130
Ice Harbor	6	693	0	0	693	215	0	0	693	231	303	0	0	693	163	303
McNary	14	1127	0	0	1127	625	0	0	1127	601	768	0	0	1127	442	716
John Day	16	2484	535	660	2484	940	0	0	2484	916	1251	0	0	2484	683	1214
The Dalles	22+2F	2074	0	0	2074	749	0	0	2074	730	992	0	0	2074	562	970
Bonneville	18+2F	1088	0	0	1047	564	0	0	1047	549	681	0	0	1047	433	640
Kootenay Lake	0	0	673	830	0	0	673	830	0	0	0	673	830	0	0	0
Coeur d'Alene Lake	0	0	223	275	0	0	223	275	0	0	0	223	275	0	0	0
Total Base System 1/		23742	29445	36320	22212	9430	28500	35154	22973	8945	11509	13000	16035	22093	6898.6	10917
c) ADDITIONAL STEP I PROJECTS																
Libby	5	600	4980	6143	307	194										
Boundary	6	1055	0	0	855	366										
Spokane Rivr Plnts 2	24	173	104	128	155	94										
Hells Canyon	3	450	0	0	392	199										
Dworshak	3	450	2015	2485	445	157				NOT APPLICABLE TO STEPS II & III						
Lower Granite	6	932	0	0	930	182										
Little Goose	6	932	0	0	928	186										
Lower Monumental	6	932	0	0	922	183										
Pelton, Rereg,& RB	7	423	274	338	418	136										
Total added Step I		5947	7373	9094	5354	1698										
d) Total Hydro		29689	52318	64533	27565	11127	44000	54273	22973	8945	11509	13000	16035	22093	6899	10917
2. THERMAL INSTALLATIONS 3/			CpEn/AnnPk=74%		13735	10216	CpEn/AnnPk=75%		13735	10262	10117	CpEn/AnnPk=76%		13735	10488	10117
3. RESOURCE ADJUSTMENTS																
a) Hydro maintenance 4/					-1561	-11	-5.3% of hydro		-1212	n.a.	n.a.	-5.3% of hydro		-1166	n.a.	n.a.
b) Peaking reserves 5/					-5264	n.a.	-11% of resc.		-4038	n.a.	n.a.	-11% of resc.		-3941	n.a.	n.a.
c) Transmission losses 6/					-1228	-667			n.a.	n.a.	n.a.			n.a.	n.a.	n.a.
4. TOTAL RESOURCES 7/			CpEn/AnnPk=62%		33247	20665	CpEn/AnnPk=61%		31457	19207	21626	CpEn/AnnPk=57%		30721	17387	21034
5. Steps I, II, & III System Loads																
a) PNW Area firm load			CpEn/AnnPk=66%		35267	23112										
b) Net of Exports + Imports					-688	331										
c) Non-Step I resources					-2019	-812										
d) Hydro Independents					-1569	-974										
e) Miscellaneous resources					-399	-991										
f) ...Net Step I,II,III System Load 8/			CpEn/AnnPk=68%		30591	20665	CpEn/AnnPk=66%		29236	19207	19078	CpEn/AnnPk=69%		25158	17387	16417
6. SURPLUS (4 - 5f)					2655	0			2221	0	2547			5563	0	4617
CRITICAL PERIOD	Starts		August 16, 1928				September 1, 1943					November 1, 1936				
	Ends		February 29, 1932				April 30, 1945					April 15, 1937				
	Length (Months)		42.5 Months				20 Months					5.5 Months				
	Study Identification		15-41				15-42					15-13				

Notes

1/ The above totals may not exactly equal the sum of the above values due to rounding. The total Base System Storage for Steps I & II includes Canadian storage.
2/ Spokane River Plants include: Little Falls, Long Lake, Nine Mile, Monroe, Upper Falls, and Post Falls.
3/ From Tables 1a, 1b and 3.
4/ Step I hydro maintenance from Tables 1a and 1b. Steps II/III peak hydro maint. same percent as Step I coordinated hydro; no energy maint. loss because impact is negligible. Hydro maintenance energy losses are not included in Steps II & III.
5/ Step I peak reserves from Table 1b. Steps II and III peak reserves are same as Step I. Adjustments to peak surplus for sustained peaking capability and less surplus in non-January months were not included in these studies, but may be considered in future studies
6/ Step I transmission losses from table 1a and 1b. Steps II and III transmission losses are not included, since it would change the energy load by the same amount.
7/ Total Resources is the sum of total lines 1b+1c+2+3. For Step I, this does not include non-Step I coordinated hydro or hydro-independents.
8/ Step I energy load from Table 1a, line 5, and January peak load from Table 1b, line 5. Steps II & III energy load from Table 3. Steps II & III peak loads are equal to Steps II and III January energy load divided by the PNWA January load factor.

TABLE 5
COMPUTATION OF CANADIAN ENTITLEMENT
FOR 2014-15 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 15-42)
B. Optimum Power Generation in the U.S. Only (From 15-12)
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km3) Reduction in Total Canadian Treaty Storage (From 15-22). For information only, not needed for this DDPB.

Determination of Dependable Capacity Credited to Canadian Storage (MW)	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	8944.9	8942.7	8909.1
Step III - Critical Period Average Generation 2/	6898.7	6898.7	6898.7
Gain Due to Canadian Storage	2046.2	2044.0	2010.4
Average Critical Period Load Factor in percent 3/	74.76	74.76	74.76
Dependable Capacity Gain 4/	2737.2	2734.2	2689.3
Dependable Capacity Limit (from Table 4)	4077.7	4077.7	4077.7
Canadian Share of Dependable Capacity 5/	**1368.6**	**1367.1**	**1344.6**
Determination of Increase in Average Annual Usable Hydro Energy (aMW)			
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Firm Energy 6/	8961.8	8959.6	8926.2
Thermal Displacement Energy 7/	2423.9	2404.6	2415.5
Remaining Usable Energy 8/	49.1	50.7	54.1
System Average Annual Usable Energy	11434.8	11414.9	11395.8
Step III (without Canadian Storage) 2/			
Firm Energy 6/	6300.7	6300.7	6300.7
Thermal Displacement Energy 7/	3879.6	3879.6	3879.6
Remaining Usable Energy 8/	294.7	294.7	294.7
System Average Annual Usable Energy	10475.1	10475.1	10475.1
Average Annual Usable Energy Gain 9/	959.7	939.8	920.8
Canadian Share of Average Annual Energy Gain 5/	**479.9**	**469.9**	**460.4**

1/ Step II values were obtained from AOP 15-42 and 22 studies.
2/ Step III values were obtained from AOP 15-13 study .
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/ One-half Dependable Capacity or Usable Energy Gain, as limited by Cap. Credit Limit.
6/ From 30-year average firm load served, which includes 7 leap years (29 days in Feb.), slightly different than Table 3.
7/ Average secondary generation limited to Potential Thermal Displacement Market.
8/ Forty percent (40%) of the remaining secondary energy.
9/ Difference between Step II and Step III Annual Average Usable Energy.

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

	2010-11	2011-12	2012-13	2013-14	2014-15
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	22033.0	21710.9	22614.8	22802.6	23013.7
Annual / January Load (%)	88.1	87.9	88.1	88.0	88.6
Critical Period (CP) Avg. Load Factor (%)	75.9	76.1	74.9	74.6	74.8
Annual Firm Exports 1/	636.7	687.9	901.2	902.5	845.4
Annual Firm Surplus (MW) 2/	578.5	554.0	570.0	786.0	93.0
THERMAL INSTALLATIONS (MW) 3/					
January Peak Capability	11761.8	11454.7	12878.0	12838.8	13734.6
CP Energy	9418.4	9480.3	10085.9	10125.5	10215.7
CP Minimum Generation	212.2	211.2	228.7	228.1	230.3
Average Annual System Export Sales	332.8	231.9	207.0	227.0	180.5
Average Annual Displaceable Market	8779.4	8968.9	9548.1	9577.7	9708.5
HYDRO CAPACITY (MW)					
Total Installed	29689.0	29322.0	29689.0	29689.0	29689.0
Base System	23742.0	23427.0	23742.0	23742.0	23742.0
STEP I/II/III CP (MONTHS)	42.5/20/5.5	42.5/20/5.5	42.5/20/5.5	42.5/20/5.5	42.5/20/5.5
BASE STREAMFLOWS AT THE DALLES 4/					
Step I 30-yr. Average Streamflow, cfs	175395	175361	175361.0	175361	175120
Step I CP Average, cfs	114765	114734	114734.0	114734	114518
Step II CP Average, cfs	101628	101578	101578.0	101578	101396
Step III CP Average, cfs	56079	56027	56027.0	56027	56034
Step I 30-yr. Average Streamflow, m^3/s	4966.63	4965.67	4965.7	4965.67	4958.85
Step I CP Average, m^3/s	3249.79	3248.92	3248.9	3248.92	3242.79
Step II CP Average, m^3/s	2877.79	2876.38	2876.4	2876.38	2871.21
Step III CP Average, m^3/s	1587.99	1586.52	1586.5	1586.52	1586.71
CAPACITY BENEFITS (MW)					
Step II CP Generation	8998.2	8944.6	8940.2	8934.7	8944.9
Step III CP Generation	7000.1	6945.5	6962.9	6942.3	6898.7
Step II Gain over Step III	1998.1	1999.1	1977.3	1992.4	2046.2
CANADIAN ENTITLEMENT	1316.4	1314.0	1320.8	1335.5	1368.6
Change due to Mica Reoperation	0.0	0.0	0.0	0.0	1.5
ENERGY BENEFITS (aMW)					
Step II Annual Firm	8981.9	8904.7	8902.5	8897.9	8961.8
Step II Thermal Displacement	2414.7	2448.7	2484.0	2469.5	2423.9
Step II Remaining Usable Secondary	67.2	69.1	55.9	55.9	49.1
Step II System Average Annual Usable	11463.8	11422.5	11422.5	11423.3	11434.8
Step III Annual Firm	6324.3	6227.6	6233.5	6169.1	6300.7
Step III Thermal Displacement	3699.3	3776.2	3874.9	3920.9	3879.6
Step III Remaining Usable Secondary	368.7	366.8	325.0	326.3	294.7
Step III System Average Annual Average	10392.3	10370.6	10433.4	10416.3	10475.1
CANADIAN ENTITLEMENT	535.7	525.9	504.5	505.5	479.8
Change due to Mica Reoperation	2.0	2.0	1.6	2.0	9.9
STEP II PEAK CAPABILITY (MW)	30601	29985	31439.1	31326	30944
STEP II PEAK LOAD (MW)	28258	28338	29264.7	29400	29236
STEP III PEAK CAPABILITY (MW)	30571	29855	31289.3	31215	30063
STEP III PEAK LOAD (MW)	24155	24195	25128.7	25162	25158

FOOTNOTES FOR TABLE 6

1. Average annual firm exports do not include the firm surplus shape or the new Thermal Installation power used outside the region (exports to shape thermal installations), but do include plant sales.

2. Average annual firm surplus is the added average annual surplus shaped in the following periods:

AOP Study	Amount Shaped (MW)
2009-10	399 Aug 15, 405 Aug 31, 1082 Sep, 894 Apr 30, 2692 May, 2974 June, and 1524 July.
2010-11	482 Aug 15, 471 Aug 31, 1474 Sep, 189 Oct, 502 April 30, 454 May, 2604 June, and 1502 July.
2011-12	1231 Sep, 313 April 30, 938 May, 3165 June, and 1198 July.
2012-13	29 Aug 31, 1392 Sep, 356 Oct, 1041 May, 2838 June, and 1205 July.
2013-14	1243 Aug 31, 1665 Sep, 243 Oct, 1633 Apr 30, 924 May, 3937 June, and 1236 July.
2014-15	1132 June

3. 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.

4. The 2000 level modified flows were used beginning with the 2009-10 DDPB with adjustments for the Grand Coulee pumping and return flows. The 2010-11, 2011-12, 2012-13, and 2013-14 DDPBs include updated adjustments for the Grand Coulee pumping but not for return flows. 2013 and 2014 Step II and Step III CP average data changes were omitted from the DDPB13 and DDPB14 documents, but have been updated in this document.

5. The Step II energy benefits for 2014-15 are based on 30-Year Joint Optimum Hydroregulation studies.

CHART 1
DURATION CURVES OF 30-YEAR MONTHLY HYDRO GENERATION
(Average monthly MW)