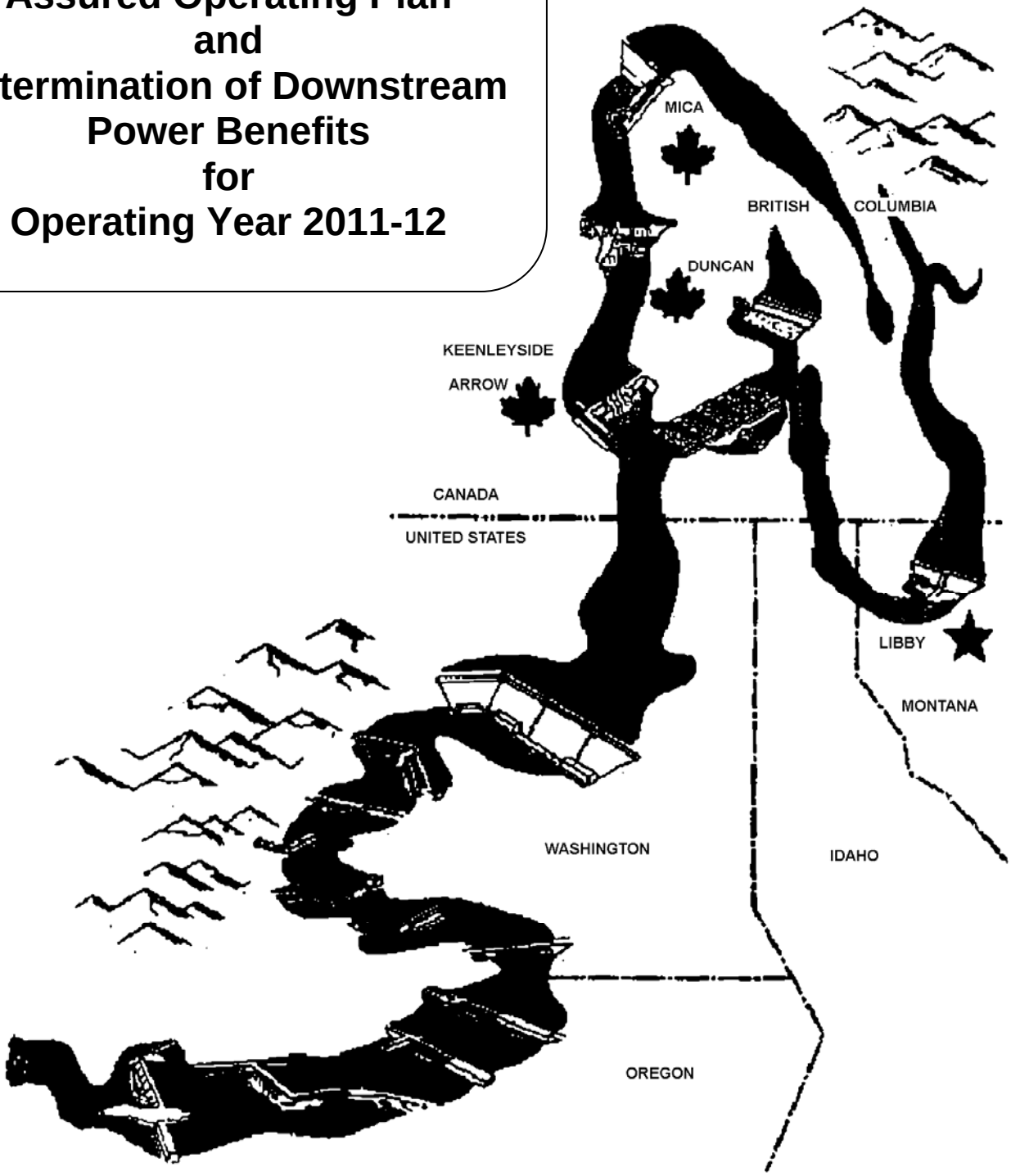
COLUMBIA RIVER TREATY
Assured Operating Plan
and
Determination of Downstream Power Benefits
for
Operating Year 2011-12



Columbia River Treaty Operating Committee March 2007

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COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR THE 2011-12 OPERATING YEAR

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 2011-12" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2011-12," both dated March 2007, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the 2011-12 Operating Year.

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

Executed for the Canadian Entity this 30 day of May, 2007.

By: _____
Robert G. Elton
Chair

Executed for the United States Entity this 6th day of April, 2007.

By: _____
Stephen J. Wright
Chairman

By: _____
BG Gregg F. Martin
Member

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COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 2011-12

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HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2011-12

March 2007

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 for the operation of the Columbia River Treaty storage in Canada during the sixth succeeding year. This 2011-12 AOP (AOP12) 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.

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

- 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 16 December 2003, and except for changes noted below, including the update to Appendix 1, dated 18 November 2003 and the November 2004 additions of Appendix 6, Streamline Procedures, and Appendix 7, Table of Median Streamflows.

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 the following changes from procedures in POP:

- Use only the first of the three Streamline Procedures, "Forecasting Loads and Resources," described in Appendix 6 of the POP;

- Revise adjustment for Canadian critical rule curve crossovers (see subsection 3(a));

- Add Arrow Project Operating Criteria (see subsection 4(c)(2)));

- Do not include Variable Refill Curve Lower Limits as described in Appendix 1 of POP, but instead at Grand Coulee only, use a fixed Variable Refill Curve Lower Limit as described in subsection 7(f); and

- Initialize the Step I power discharge requirements (PDR) at AOP11 levels as described in subsection 7(f), instead of minimum discharge as described in subsection 2.3.b(3) of POP.

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:

(a) The Critical Rule Curves (CRC), Upper Rule Curves (URC), and the related rule curves and data for each project used to compute the individual project Operating Rule Curves (ORC);

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

(c) The supporting data and model used to simulate the 30-year operation for the Step I Joint Optimum (AOP12-41) 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.

2. Development of the Assured Operating Plan

a) 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 2011-12 operating year estimated loads and resources in the USA Pacific Northwest (PNW) Area,

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 AOP12 is based on a 30-year streamflow 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 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 kilometers (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.

b) 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 AOP12, 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

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. Annex A, paragraph 7, of the Treaty defines the limits to any reduction in the downstream power benefits in the USA resulting from that change in operation. Using the storage operation for optimum generation in both Canada and the USA, there is a 2.0 aMW increase in the Canadian Entitlement for average annual usable energy and no change in the dependable capacity compared to the operation for optimum generation in the USA alone. (See Table 5 from the DDPB12, columns A and B.)

Since there is no reduction in entitlement, the Entities have determined in Section 3 of the 2011-12 DDPB 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 2011-12 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 CRC's are higher than lower numbered CRC's, and past practice was for the hydro regulation model to lower the CRC2, CRC3, or CRC4 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, the Assured Refill Curve (ARC) and the Variable Refill Curve (VRC), 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 Curve

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 streamflows at The Dalles, Oregon, during the 30-year streamflow period, which has approximately a 95% probability of exceedance.

(2) Variable Refill Curve

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 AOP12, the past practice of including VRC Lower Limits (VRCLL) for all projects with VRCs was modified to use a fixed VRCLL for Grand Coulee only.

Tables 4-6 illustrate the range of VRCs for Mica, Arrow, and Duncan for the 30-year streamflow period. In actual operation in 2011-12, the PDRs and VRCLLs will be based on the forecast of unregulated runoff at The Dalles.

c) Operating Rule Curve Lower Limit (ORCLL)

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 VRC's permit storage to be emptied and sufficient natural flow is not available to carry the load prior to the start of the freshet. Such rule curves shall limit the ORC to be no lower than the ORCLLs. The ORCLLs are developed for 1936-37 water conditions which include the lowest January through April unregulated streamflows at The Dalles during the 30-year streamflow period. The ORCLLs for Mica, Arrow, and Duncan are shown in Tables 4, 5, and 6 respectively.

d) Upper Rule Curve (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 streamflow 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 Curve

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 it 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 streamflow period are included in Table 10 to illustrate the probable future range of these curves based on historical water conditions.

4. Operating Rules

The AOP12-41 System Regulation Study was used to develop and test the operating rules and rule curves. The System Regulation Study storage operation results for the

whole of Canadian Treaty Storage for the 30-year streamflow period are shown in Table 11. The Study contains the agreed-upon ORCs and CRCs, and operating procedures and constraints, such as maximum and minimum project elevations, discharges, and draft rates. These constraints are included as part of this operating plan and are listed in Appendix A.

The following rules and other operating criteria included in the AOP12-41 System Regulation Study will apply to the operation of Canadian Treaty Storage in the 2011-12 Operating Year.

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 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 AOP12 is not intended to set 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 1.1a 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).

APOC Implementation: In the Detailed Operating Plan, the default implementation of the APOC storage limits 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 1.1a. 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 AOP12 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 that closely approximate International Joint Commission rules for Kootenay Lake.

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.(k) of the Columbia River Treaty, which states:

> "...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 2011-12 DOP (DOP12) 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 DOP12. Failing agreement on updating the data and/or criteria, the DOP12 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 2011-12 Operating Year shall be guided by the DOP12.

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 streamflow during any period, straight-line interpolation between the period-end points should not be assumed. During the storage drawdown season, Canadian Treaty Storage should not be drafted below its period-end point at any time during the period unless it can be conservatively demonstrated that sufficient inflow is available, in excess of the minimum outflow required to serve power demand, to refill the reservoir to its end-of-period value as required.

During the storage evacuation and refill season, operation will be consistent with the FCOP. When refill of Canadian Treaty Storage is being guided by Flood 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 2011-12."

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 2011 through

31 July 2012 period covered by this AOP, and includes transmission losses and scheduling guidelines for delivery of the Canadian Entitlement.

7. Summary of Changes from the 2010-11 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 AOP12 are based on Bonneville Power Administration's (BPA) March 2006 White Book (WB06)[5] medium-case load forecast. The WB06 forecast for the 2011-12 regional firm load is 22,166 annual aMW, and is based on a 1.11% annual load growth from the 2011 to 2012 operating year. This forecast for the AOP12 is 127 aMW (0.6%) less than the WB04 forecast used in the AOP11. However, because a larger portion of the Utah Power & Light load is excluded in the AOP12 (explained below) the net PNWA firm load from the AOP11 to AOP12 is reduced by 322 annual aMW (1.4%). Other load assumptions and changes include:

- The procedure to exclude Utah Power & Light (UP&L) loads and imports in eastern Idaho from the White Book totals was modified from that used in the AOP11. Annex B, paragraph 7, of the Treaty requires the area served by UP&L in 1964 to be excluded from the PNWA firm load. Portions of the UP&L load and import supporting it were excluded from previous AOPs, but the correct amount to exclude has been difficult to determine because of BPA loads within the UP&L area and new research indicates almost all should be excluded. The AOP12 will exclude 99% of the UP&L load from the PNWA firm load, and all of the import from Utah that meets that load will continue to be excluded. The net effect on the AOP12 Step I loads and resources is a 455 aMW reduction in the PNWA firm load, compared to a 261 aMW reduction in the AOP11. The remaining 5 aMW of UP&L load in Idaho is included in the PNWA load.
- The average critical period load factor increased from 75.89% in AOP11 (from WB04) to 76.07% in AOP12 (from WB06). This was mainly due to changes in the peak load forecast.
- Updated irrigation pumping loads for Grand Coulee are included in the Regional Firm Load. Both these irrigation loads and the pumping amounts were obtained from the February 2006 Pacific Northwest Coordination Agreement (PNCA) data submittal from the Bureau of Reclamation. Differences from the February 2005 PNCA used in AOP11 vary from 6 MW in June to 73 MW in February, with a net annual difference of 10 aMW.

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.

- It was agreed that 125 aMW of Canadian Entitlement would be assumed to serve load in the PNWA., and the estimated remaining amount of 385 aMW exported to B.C. This assumption does not set a precedent for future AOP studies, and does not affect respective positions on the appropriate amount. Compared to AOP11, there is a 143 aMW reduction in Entitlement energy remaining in the U.S., 24.5% of the total Canadian Entitlement, compared to 50% for the AOP11. The estimated and the computed Canadian Entitlement are shown below:

During 1 August 2011 – 31July 2012

Canadian Entitlement	**Energy (aMW)**		**Capacity (MW)**	
Return	Estimated	Computed	Estimated	Computed
Export to BC	385.0	400.9	1019.0	983.0
Retained in PNW	125.0	125.0	331.0	331.0
Total	510.0	525.9	1350.0	1314.0

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 AOP11, Flows-Out (exports that are mostly to the southwest but also include the Entitlement) decreased by 10 annual aMW, and Flows-In (imports) decreased by 28 annual aMW.

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

The Step I System Load is reduced by Hydro Independent generation, Non-Step I Coordinated Hydro, and Miscellaneous Non-Thermal Resources. The most notable changes are a 193 annual aMW decrease in Hydro Independent generation (1928-29 water year) due to updated data for a number of projects that were or will be decommissioned, otherwise out of service or now determined not to be in the PNWA; a 184 annual aMW decrease in Step I coordinated hydro generation, mostly due updated plant data at Mid-Columbia projects and increased spill at non-Base System Snake River projects.

d) Thermal Installations

Because of increasing difficulty in forecasting Thermal Installations, the Entities again used the Streamline Procedure for “Loads and Resources” for determining Thermal Installations, as used in the 2006-07 and 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. The CGS annual average generation increased by 123 aMW from AOP11 to AOP12, due to no maintenance outage. The total thermal installations increased by 88 annual aMW from AOP11 to AOP12 due to a combination of all changes in loads and resources explained above.

e) Hydro Project Modified Streamflows

The base unregulated streamflows used in the System Regulation Studies were the 2000 Modified Streamflows published by BPA in May 2004. Modified Streamflows are determined from historic observed streamflows, adjusted to remove the storage regulation effect at modeled upstream projects, and modified to a common level of irrigation depletions and reservoir evaporation. Forecasts of Grand Coulee pumping estimates were updated from the February 2006 PNCA data submittal and were based on the previous five year average discharge into Banks Lake. The annual average change from AOP11 is only +33 cfs, with -332 cfs in August 16-31, and +320 cfs in April 1-15. With the addition of Lime Point, the Step1 streamflow file now contains 82 projects, Step II has 37 projects and Step III contains 34 projects.

f) Hydro Project Rule Curves

The critical rule curves, refill curves, and Mica/Arrow operating criteria were updated in accordance with procedures defined in the POP, except that the VRCLLs were eliminated for all projects but Grand Coulee, which used a fixed VRCLL for all three forecast levels, 98.7, 117.2, and 135.7 km^3 (80, 95, and 110 Maf) equal to the ORCLL for January and February and based on historic minimum elevations for firm power operation of 1225 feet in March-April, 1240 feet in May, and 1285 feet in June. Also, there were several changes to the Step I Refill Study procedures that were agreed to for this AOP only, because they require further refinement and testing. These procedures led to the alternative HYDSIM PDR values shown in Tables 4, 5, and 6. The most notable of which is initializing the PDRs for the VRC's to the AOP11 levels instead of minimum flow as in previous studies. Other changes and notable assumptions include:

- 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 30-year URC data was updated from new studies by the Corps of Engineers, with large changes at major projects in May and June in most water years. These studies were designed to develop a flood control data set for 1928-29 through 1997-98 water years that is consistent with current AOP operating criteria (including the 4.08/3.6 Mica/Arrow flood control allocation, Libby standard flood control, Hungry Horse variable flood control, and the 2000 Modified Flows), and were performed in coordination with all the Treaty parties; and

- 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.

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

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. Other changes and 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.

- The amount of spill at the non-Base System projects Lower Granite, Little Goose, and Lower Monumental was significantly increased from that in the AOP11. This caused a decrease in average critical period generation of 46 aMW at Lower Granite, 34 aMW at Little Goose, and 47 aMW at Lower Monumental. The spill varies from month to month and is either a fixed amount or a function of the regulated outflow.

- Grand Coulee is full through August 31 at the beginning of the critical period 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 were inadvertently not fully updated to the 2006 PNCA data submittal. The Operating Committee expects to update this data in the next full AOP.

- Head vs. Generation per Flow tables (h/k) were updated for Noxon and Corra Linn, but the effect is small.

- Generation vs discharge and/or spill vs discharge tables were updated at Brilliant, Cabinet Gorge, Post Falls, Upper Falls, Monroe Street, Little Falls, Nine Mile, Wanapum, Priest Rapids, and Oak Grove. The most noticeable changes in average critical period generation are: Wanapum (-15 aMW), Priest Rapids (-20 aMW), Cabinet Gorge (-10 aMW), Brilliant (+45 aMW), and Oak Grove (+8 aMW).

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

1 "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System

Regulation Study 12-41," dated 20 February 2007.

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

3 "Report on 2000 Level Modified Streamflow, 1928 to 1999, Columbia River and Coastal 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 "2006 Pacific Northwest Loads & Resources Study, Operating Years 2007 through 2016", dated March 2006, and published on 1 December 2006. There was no 2005 White Book, which is why the AOP11 used the 21 April 2005 Draft of the 2004 White Book that was published 8 September 2005.

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2011-12 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	-	3,364.2	-	34,000	15,000
	2,170 - 3,300	25,000	-	0	-	15,000
	1,500 - 2,170	20,000	-	0	-	15,000
	0 - 1,500	32,000	-	0		15,000
August 16-31	2,710 - FULL	-	3,529.2	-	34,000	15,000
	1,950 - 2,710	25,000	-	0	-	15,000
	0 - 1,950	32,000	-	0	-	15,000
September	3,530 - FULL	-	3,529.2	-	34,000	10,000
	3,400 - 3,530	24,000	-	0	-	10,000
	2,800 - 3,400	27,000	-	0	-	10,000
	0 - 2,800	32,000	-	0	-	10,000
October	3,440 - FULL	-	3,428.4	-	34,000	10,000
	2,600 - 3,440	19,000	-	0	-	10,000
	2,000 - 2,600	22,000	-	0	-	10,000
	0 - 2,000	32,000	-	0	-	10,000
November	3,340 - FULL	21,000	-	0	-	10,000
	3,130 - 3,340	19,000	-	0	-	10,000
	420 - 3,130	25,000	-	0	-	10,000
	0 - 420	32,000	-	0	-	10,000
December	2,740 - FULL	25,000	-	204.1	-	10,000
	1,800 - 2,740	22,000	-	204.1	-	10,000
	300 - 1,800	27,000	-	204.1	-	10,000
	0 - 300	32,000	-	204.1	-	10,000
January	2,640 - FULL	24,000	-	204.1	-	12,000
	2,180 - 2,640	27,000	-	204.1	-	12,000
	1,350 - 2,180	25,000	-	204.1	-	12,000
	0 - 1,350	29,000	-	204.1	-	12,000
February	1,370 - FULL	21,000	-	0	-	12,000
	900 - 1,370	26,000	-	0	-	12,000
	500 - 900	21,000	-	0	-	12,000
	0 - 500	26,000	-	0	-	12,000
March	800 - FULL	17,000	-	0	-	12,000
	770 - 800	26,000	-	0	-	12,000
	510 - 770	22,000	-	0	-	12,000
	0 - 510	25,000	-	0	-	12,000
April 1-15	890 - FULL	20,000	-	0	-	12,000
	350 - 890	10,000	-	0	-	12,000
	220 - 350	12,000	-	0	-	12,000
	0 - 220	22,000	-	0	-	12,000
April 16-30	570 - FULL	10,000	-	0	-	10,000
	110 - 570	15,000	-	0	-	10,000
	20 - 110	10,000	-	0	-	10,000
	0 - 20	15,000	-	0	-	10,000
May	640 - FULL	8,000	-	0	-	8,000
	520 - 640	12,000	-	0	-	8,000
	220 - 520	8,000	-	0	-	8,000
	0 - 220	10,000		0	-	8,000
June	1,610 - FULL	8,000	-	0	-	8,000
	1,020 - 1,610	10,000	-	0	-	8,000
	810 - 1,020	14,000		0	-	8,000
	0 - 810	18,000	-	0	-	8,000
July	3,180 - FULL	-	3,467.2	-	34,000	10,000
	2,670 - 3,180	-	3,405.2	-	34,000	10,000
	1,160 - 2,670	20,000	-	0	-	10,000
	0 - 1,160	31,000	-	0	-	10,000

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
2011-12 ASSURED OPERATING PLAN

Period	Volume Runoff Period	The Dalles Volume Runoff (Maf)	Maximum Storage Limit 1/ 2/ (ksfd)	Maximum Outflow Limit 3/ (cfs)	Minimum Outflow Limit 4/ (cfs)
August 15 - December	-		URC	-	10,000
January	-		URC	70,000	10,000
February	1 Feb - 31 Jul	≤ 70	URC	60,000	20,000
		>70 to <80	URC to 1800		
		≥ 80	1800		
March	1 Mar - 31 Jul	≤ 65	URC	-	20,000
		>65 to <75	URC to 900		
		≥ 75	900		
April 15	1 Apr - 31 Jul	≤ 61	URC	-	15,000
		>61 to <70	URC to 900		
		≥ 70	900		
April 30	1 Apr - 31 Jul	≤ 61	URC	-	10,000
		>61 to <70	URC to 1000		
		≥ 70	1000		
May	1 May - 31 Jul	≤ 68	URC	-	10,000
		>68 to <70	URC to 2100		
		≥ 70	2100		
June	1 Jun - 31 Jul	≤ 33	URC	-	5,000
		>33 to <35	URC to 3400		
		≥ 35	3400		
July	-		URC	-	10,000

Notes:

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

2/ Interpolate when there are two values. For example, if the February-July volume runoff is between 70 Maf and 80 Maf, then the Maximum Storage Limit is interpolated between February's URC and 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 2011-12 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	10,000	10,000	5,000	10,000
End-of-Period Maximum Storage Limits (ksfd)									
1928-29	-	-	URC	URC	URC	URC	URC	3500.3	-
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	2100.0	3400.0	-
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	3400.0	-
1935-36	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	3478.6	-
1937-38	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1938-39	-	-	1928.8	930.4	1163.2	1241.8	URC	URC	-
1939-40	-	-	1987.4	1202.8	1933.1	1970.2	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	2100.0	3400.0	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	1852.7	966.9	1024.5	1114.2	URC	3400.0	-
1945-46	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1946-47	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1947-48	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1948-49	-	-	1800.0	900.0	900.0	1000.0	2944.2	URC	-
1949-50	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1950-51	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1951-52	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1952-53	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1953-54	-	-	1800.0	900.0	900.0	1000.0	2100.0	URC	-
1954-55	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1955-56	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1956-57	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1957-58	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-

TABLE 1.1c
APOC IMPLEMENTATION
DISTRIBUTION FACTORS FOR THE DALLES
2011-12 ASSURED OPERATING PLAN

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

Notes:

1/ Unless otherwise agreed, the DOP12 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	≤ 68	≤ 83.9	URC	URC
June	0.6123	39.8	49.1	≥ 35	≥ 43.2	3400	8318.4

TABLE 2
COMPARISON OF 2011-12 ASSURED OPERATING PLAN
STUDY RESULTS

Study 12-41 provides Optimum Generation in Canada and in the United States.
Study 12-11 provides Optimum Generation in the United States only.

	Study No. 12-41	Study No. 12-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	11936.0	11935.9	0.1		
Canada 2/, 3/	2952.6	2909.1	43.6		
Total	14888.6	14845.0	43.6	3	130.8
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	29995.9	30018.8	-22.9		
Canada 2/, 5/	5787.5	5745.8	41.7		
Total	35783.4	35764.6	18.8	1	18.8
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3100.3	3078.7	21.6		
Canada 2/, 7/	288.5	302.4	-13.9		
Total	3388.8	3381.1	7.7	2	15.4
			Net Change in Value =		165.0

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 1937.

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)
2011 - 12 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	3522.6	3409.0	3002.9	2274.1	1526.8	783.7	505.1	258.7	173.5	469.0	2114.7	3101.2
1929-30	3396.4	3504.2	3328.0	2470.9	1956.8	1431.0	512.8	160.5	0.0	0.0	220.2	623.7	1169.2	2474.4
1930-31	2862.9	3176.4	3182.0	2452.1	2087.7	1236.3	746.5	67.4	0.0	0.0	0.0	267.4	945.5	2093.9
1931-32	2004.5	1834.3	1157.3	1064.2	612.5	0.0	0.0	0.0						
							ARROW							
1928-29	3579.6	3579.4	3322.8	3032.9	2770.8	2489.7	1532.6	932.1	599.2	685.7	739.2	1666.4	3203.6	3552.9
1929-30	3539.1	3535.9	3001.3	2950.1	2015.1	1460.9	471.2	171.8	0.0	70.0	447.6	1453.4	2562.9	3268.6
1930-31	3369.1	3298.5	2800.1	2730.4	1851.9	1247.5	279.3	144.9	0.0	0.0	1.4	774.7	1820.5	1729.9
1931-32	1778.5	1889.7	1681.5	1129.7	749.7	226.1	2.1	0.0						
							DUNCAN							
1928-29	705.8	705.8	698.8	685.2	621.0	440.2	357.0	259.5	164.8	140.0	151.3	268.8	543.6	675.7
1929-30	675.4	652.1	593.4	590.6	543.1	402.4	219.4	45.1	0.0	1.1	34.2	109.0	315.2	429.6
1930-31	468.3	523.1	581.1	539.2	550.1	333.6	143.3	0.0	0.0	0.2	0.0	157.2	150.8	139.2
1931-32	171.4	96.6	84.6	113.7	69.2	0.0	0.0	0.0						
							COMPOSITE							
1928-29	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3416.4	1975.3	1269.1	1084.4	1064.0	2404.2	5861.9	7329.8
1929-30	7610.9	7692.2	6922.7	6011.6	4515.0	3294.3	1203.4	377.4	0.0	71.1	702.0	2186.1	4047.3	6172.6
1930-31	6700.3	6998.0	6563.2	5721.7	4489.7	2817.4	1169.1	212.3	0.0	0.2	1.4	1199.3	2916.8	3963.0
1931-32	3954.4	3820.6	2923.4	2307.6	1431.4	226.1	2.1	0.0						

Note: These rule curves are input to the AOP 2012 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
2011 - 12 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	51.4	634.3	1236.7	1415.3	1480.6	1497.1	1491.9	1480.4	1487.2	1512.2	1575.4	2352.5	3486.0	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2759.4	2581.8	2521.5	2513.1	2554.0	3055.4	3353.0	3529.2
1929-30							1737.1	1520.3	1450.3	1459.9	1616.4	2449.2	3069.2	"
1930-31							1994.9	1787.1	1712.6	1700.5	1790.8	2468.2	3143.9	"
1931-32							951.3	750.7	682.8	671.5	788.8	1577.3	2847.6	"
1932-33							857.9	692.6	642.1	628.6	706.3	1476.2	2685.0	"
1933-34							40.5	0.0	0.0	0.0	0.8	1222.2	2936.5	"
1934-35							1238.9	1054.9	1016.6	1023.2	1093.3	1793.7	2796.3	"
1935-36							1084.9	901.4	851.8	838.0	933.0	1803.6	3074.7	"
1936-37							2746.1	2548.0	2472.8	2453.5	2542.5	3067.5	3384.5	"
1937-38							1230.2	1046.3	978.5	971.7	1064.7	1801.5	2939.4	"
1938-39							1705.0	1565.5	1504.9	1518.6	1629.8	2396.6	3348.0	"
1939-40							1493.2	1317.0	1273.8	1281.5	1411.0	2200.0	3110.4	"
1940-41							2180.0	1992.7	1937.7	1945.0	2122.0	2846.5	3366.7	"
1941-42							1749.6	1566.2	1503.0	1487.1	1563.2	2222.1	3128.1	"
1942-43							1867.2	1661.0	1594.8	1578.7	1731.1	2429.0	3177.5	"
1943-44							2851.8	2637.9	2576.3	2566.1	2634.7	3177.2	3524.2	"
1944-45							2628.4	2451.5	2403.8	2404.2	2453.8	2952.8	3398.7	"
1945-46							651.6	437.4	367.8	344.0	435.6	1275.5	2843.5	"
1946-47							765.3	604.8	564.0	562.0	678.8	1536.2	2911.7	"
1947-48							714.2	533.1	477.2	449.0	529.3	1331.7	2798.4	"
1948-49							2410.8	2204.2	2121.3	2104.9	2182.4	2707.6	3529.2	"
1949-50							1069.7	849.1	769.6	746.2	831.0	1552.9	2609.7	"
1950-51							1060.9	888.0	840.5	834.9	948.7	1672.0	2971.2	"
1951-52							1467.7	1252.2	1179.2	1150.1	1231.9	1967.4	3118.5	"
1952-53							1749.0	1551.3	1487.8	1471.6	1531.3	2122.6	3085.5	"
1953-54							624.7	439.3	400.5	390.2	474.1	1247.9	2581.8	"
1954-55							1384.5	1215.0	1168.0	1164.4	1250.9	1893.6	2776.3	"
1955-56							932.9	745.8	678.1	657.2	746.0	1570.0	2885.8	"
1956-57							1101.5	907.1	854.0	845.4	934.8	1656.1	3216.3	"
1957-58							935.2	753.8	707.1	703.9	809.3	1552.9	2978.9	"
DISTRIBUTION FACTORS							0.9750	0.9770	0.9740	0.9812	0.9650	0.7950	0.4950	N/A
FORECAST ERRORS (KSFD)							728.1	521.9	455.3	420.3	420.3	401.5	397.1	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	22350	55100
VARIABLE REFILL CURVES					80	MAF	3000	3000	3000	3000	3000	3000	32000	38000
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	3000	3000	3000	3000	3000	3000	18000	32300
					110	MAF	3000	3000	3000	3000	3000	3000	18000	32300
OPERATING RULE CURVE LOWER LIMITS (KSFD)							279.8	28.5	0.0	0.0				

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2011 - 12 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	696.5	1488.8	1556.4	1638.0	1718.7	1887.5	3096.6	3579.6	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							3579.6	3479.2	3362.0	3284.8	3402.6	3579.6	3541.1	3579.6
1929-30							2106.2	1826.6	1830.5	1827.7	2128.8	3343.8	3579.6	"
1930-31							2609.4	2301.3	2204.6	2160.3	2363.1	3197.7	3560.1	"
1931-32							0.0	0.0	0.0	0.0	0.0	486.5	2703.8	"
1932-33							"	"	"	"	"	437.3	2592.8	"
1933-34							"	"	"	"	"	867.9	3077.9	"
1934-35							926.5	855.8	965.1	981.2	1156.4	2253.3	3093.4	"
1935-36							1079.8	912.3	866.6	826.0	984.2	2336.0	3397.0	"
1936-37							3579.6	3579.6	3579.6	3510.0	3579.6	3579.6	3579.6	"
1937-38							0.0	0.0	0.0	0.0	0.0	1048.2	2928.4	"
1938-39							2166.1	1907.2	1821.8	1777.3	2057.6	3117.5	3579.6	"
1939-40							1735.2	1629.0	1678.2	1758.0	2026.4	3060.0	"	"
1940-41							3242.9	2984.4	2925.5	3003.6	3431.7	3579.6	"	"
1941-42							2361.1	2107.3	2056.6	2005.3	2261.2	3289.0	3503.0	"
1942-43							1127.9	806.1	729.7	663.4	1013.0	2297.1	3463.4	"
1943-44							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	"
1944-45							"	3440.9	3361.6	3312.9	3426.5	"	"	"
1945-46							0.0	0.0	0.0	0.0	0.0	377.9	2788.1	"
1946-47							"	"	"	"	"	1056.0	2944.4	"
1947-48							"	"	"	"	"	493.7	2814.6	"
1948-49							1496.4	1207.0	1152.5	1112.1	1371.6	2124.0	3416.8	"
1949-50							0.0	0.0	0.0	0.0	0.0	496.2	2460.3	"
1950-51							"	"	"	"	"	772.1	2958.4	"
1951-52							"	"	"	"	"	820.1	2929.8	"
1952-53							452.5	174.6	132.8	93.1	294.3	1391.6	2976.0	"
1953-54							0.0	0.0	0.0	0.0	0.0	117.9	2708.4	"
1954-55							488.9	418.0	457.5	424.9	627.8	2097.0	2709.0	"
1955-56							0.0	0.0	0.0	0.0	0.0	489.8	2818.2	"
1956-57							"	"	"	"	"	345.9	2949.6	"
1957-58							"	"	"	"	"	553.4	2895.7	"
DISTRIBUTION FACTORS							0.9710	0.9747	0.9691	0.9741	0.9530	0.7483	0.4631	N/A
FORECAST ERRORS (KSFD)							1485.5	1095.5	954.5	809.9	809.9	723.4	679.5	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	60550	89140
VARIABLE REFILL CURVES					80	MAF	5000	5000	5000	5000	5000	5000	66200	69200
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	5000	5000	5000	5000	5000	5000	43000	57000
					110	MAF	5000	5000	5000	5000	5000	5000	5000	46300
OPERATING RULE CURVE LOWER LIMITS (KSFD)							157.9	27.6	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
2011 - 12 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	36.9	97.3	163.6	194.2	211.8	222.9	233.1	242.3	256.4	267.3	282.8	434.0	555.0	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							368.7	351.1	360.0	356.8	373.4	435.4	578.8	705.8
1929-30							367.1	349.1	357.7	354.2	378.4	455.9	590.3	"
1930-31							311.6	294.9	307.1	308.6	331.3	405.4	578.8	"
1931-32							0.0	0.0	0.0	0.0	0.0	161.5	466.5	"
1932-33							"	"	"	"	"	0.0	331.4	"
1933-34							"	"	"	"	38.2	241.0	536.7	"
1934-35							22.9	12.7	36.4	36.7	60.9	212.9	468.5	"
1935-36							10.0	0.0	6.4	5.2	32.8	215.9	526.0	"
1936-37							304.5	286.0	296.8	293.6	314.6	390.4	560.5	"
1937-38							0.0	0.0	4.1	11.1	41.3	210.7	494.4	"
1938-39							134.0	122.7	136.2	138.2	170.0	302.6	560.9	"
1939-40							122.1	115.6	136.8	148.4	182.8	306.2	547.6	"
1940-41							220.6	211.4	228.4	241.8	287.3	394.7	573.4	"
1941-42							136.8	130.0	146.9	149.2	178.5	312.0	537.2	"
1942-43							125.7	111.7	127.2	127.9	166.7	319.0	522.5	"
1943-44							374.9	361.9	375.3	374.1	397.7	462.6	609.1	"
1944-45							272.9	260.1	274.7	274.0	292.2	376.5	563.0	"
1945-46							0.0	0.0	0.0	0.0	0.0	102.0	463.8	"
1946-47							"	"	"	"	"	147.0	473.8	"
1947-48							"	"	"	"	"	164.0	487.8	"
1948-49							186.3	169.4	181.5	179.2	204.5	337.7	588.9	"
1949-50							0.0	0.0	0.0	0.0	8.0	167.8	424.7	"
1950-51							"	"	"	"	0.0	132.0	456.1	"
1951-52							16.2	1.6	19.8	18.7	44.6	225.4	505.7	"
1952-53							13.9	2.1	18.3	"	41.7	200.3	469.7	"
1953-54							0.0	0.0	0.0	0.0	0.0	61.3	400.3	"
1954-55							"	"	"	"	"	146.8	402.6	"
1955-56							"	"	"	"	"	112.4	456.9	"
1956-57							"	"	"	"	"	162.6	523.5	"
1957-58							"	"	"	"	"	102.3	476.9	"
DISTRIBUTION FACTORS							0.9720	0.9790	0.9740	0.9790	0.9570	0.7580	0.4690	N/A
FORECAST ERRORS (KSFD)							127.7	104.3	105.0	93.8	93.8	86.9	78.0	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	100	100	100	100	100	100	100	100	100	100	100	293	3997	2456
VARIABLE REFILL CURVES					80	MAF	100	100	100	100	100	1400	1800	1800
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	100	100	100	100	100	100	600	1100
					110	MAF	100	100	100	100	100	100	600	1000
OPERATING RULE CURVE LOWER LIMITS (KSFD)							78.2	19.0	0.0	0.0				

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2011 - 12 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	3203.0	3086.0	2958.9	2958.9	2958.9	3068.3	3529.2	3529.2
1929-30	"	"	"	"	"	"	3147.0	2979.3	2791.2	2791.2	2791.2	2823.2	3248.4	"
1930-31	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3331.6	3529.2	"
1931-32	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2299.1	3387.3	"
1932-33	"	"	"	"	"	"	"	"	"	"	"	1661.4	2868.9	"
1933-34	"	"	"	"	"	"	"	"	"	"	1838.3	2743.4	3216.5	"
1934-35	"	"	"	"	"	"	"	"	"	"	1472.2	1918.6	2873.0	"
1935-36	"	"	"	"	"	"	"	"	"	"	1556.5	2718.7	3529.2	"
1936-37	"	"	"	"	"	"	3111.5	2908.1	2689.7	2689.7	2689.7	2800.6	3382.0	"
1937-38	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1513.3	2307.3	3253.6	"
1938-39	"	"	"	"	"	"	2836.9	2385.3	1894.2	1894.2	1961.6	3164.1	3305.7	"
1939-40	"	"	"	"	"	"	2994.5	2679.5	2339.7	2339.7	2339.7	3114.5	3335.3	"
1940-41	"	"	"	"	"	"	3320.1	3309.8	3299.6	3299.6	3299.6	3339.5	3396.4	"
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	"	"	"	"	"	"	2826.7	2375.2	1874.0	1874.0	1874.0	2395.8	,,	"
1945-46	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2710.5	3296.8	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	2535.7	3529.2	"
1947-48	"	"	"	"	"	"	"	"	"	"	"	2327.9	"	"
1948-49	"	"	"	"	"	"	"	"	"	"	1498.9	2430.8	3525.1	"
1949-50	"	"	"	"	"	"	"	"	"	"	1472.2	1472.2	2727.0	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2469.8	3119.9	"
1951-52	"	"	"	"	"	"	"	"	"	"	1546.2	2498.6	3249.4	"
1952-53	"	"	"	"	"	"	"	"	"	"	1472.2	1953.5	3109.6	"
1953-54	"	"	"	"	"	"	"	"	"	"	,,	1863.0	2342.3	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1472.2	2926.5	3516.9
1955-56	"	"	"	"	"	"	"	"	"	"	"	2284.7	3282.4	3529.2
1956-57	"	"	"	"	"	"	"	"	"	"	"	3000.5	3529.2	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2574.7	"	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2011 - 12 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	3220.9	3579.6	3579.6
1929-30	"	"	"	"	"	"	3134.4	3053.8	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	2866.8	2866.8	2866.8	2879.8	"	"
1937-38	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	2073.1	"	"
1938-39	"	"	"	"	"	"	2846.0	2504.8	2127.1	2127.1	2127.1	2267.4	"	"
1939-40	"	"	"	"	"	"	2988.4	2776.0	2540.8	2540.8	2540.8	3121.0	"	"
1940-41	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3331.7	"	"
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	2184.5	"	"
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)
2011 - 12 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	436.0	655.1	"
1930-31	"	"	"	"	"	"	390.7	288.3	288.3	288.3	292.9	434.2	656.2	"
1931-32	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	275.6	626.7	"
1932-33	"	"	"	"	"	"	"	"	"	"	"	133.0	492.4	689.5
1933-34	"	"	"	"	"	"	"	"	"	"	509.3	605.2	687.2	705.8
1934-35	"	"	"	"	"	"	"	"	"	"	65.5	167.7	485.6	"
1935-36	"	"	"	"	"	"	"	"	"	"	104.3	336.7	660.2	"
1936-37	"	"	"	"	"	"	374.8	258.1	258.1	258.1	258.1	377.7	621.4	"
1937-38	"	"	"	"	"	"	290.1	96.8	96.8	96.8	117.0	293.8	631.4	"
1938-39	"	"	"	"	"	"	285.1	87.2	87.2	87.2	112.1	337.8	558.5	"
1939-40	"	"	"	"	"	"	297.8	111.4	111.4	111.4	111.4	305.6	582.5	"
1940-41	"	"	"	"	"	"	344.4	200.1	200.1	200.1	216.2	371.9	619.9	"
1941-42	"	"	"	"	"	"	326.1	165.3	165.3	165.3	165.3	316.8	541.0	"
1942-43	"	"	"	"	"	"	329.3	171.4	171.4	171.4	171.4	242.1	444.0	"
1943-44	"	"	"	"	"	"	411.1	327.2	327.2	327.2	327.2	440.4	672.2	"
1944-45	"	"	"	"	"	"	381.5	270.7	270.7	270.7	270.7	393.7	653.5	"
1945-46	"	"	"	"	"	"	273.7	65.5	65.5	65.5	73.2	327.0	677.9	"
1946-47	"	"	"	"	"	"	"	"	"	"	83.1	313.8	637.8	"
1947-48	"	"	"	"	"	"	"	"	"	"	65.5	250.0	658.3	"
1948-49	"	"	"	"	"	"	368.0	245.0	245.0	245.0	264.6	485.8	705.8	"
1949-50	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	181.5	533.9	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	527.9	606.7	"
1951-52	"	"	"	"	"	"	"	"	"	"	95.4	295.2	595.3	"
1952-53	"	"	"	"	"	"	"	"	"	"	65.5	188.5	489.6	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	189.7	435.9	688.8
1954-55	"	"	"	"	"	"	"	"	"	"	"	72.3	"	694.6
1955-56	"	"	"	"	"	"	"	"	"	"	"	321.2	636.6	705.8
1956-57	"	"	"	"	"	"	"	"	"	"	71.7	376.5	691.9	"
1957-58	"	"	"	"	"	"	"	"	"	"	65.5	334.7	683.1	"

TABLE 10
(English Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2011 - 12 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3416.4	3296.3	3381.6	3498.2	3745.7	5881.5	7449.1	7814.6
1929-30	"	"	"	"	"	"	"	"	3344.7	3445.9	"	5751.1	7203.8	"
1930-31	"	"	"	"	"	"	3371.0	"	3381.6	3498.2	"	5854.5	7259.0	"
1931-32	"	"	"	"	"	"	1187.4	797.3	682.8	671.5	788.8	2225.3	6017.9	"
1932-33	"	"	"	"	"	"	1094.0	739.2	642.1	628.6	706.3	1913.5	5609.2	7798.3
1933-34	"	"	"	"	"	"	515.9	75.1	0.0	0.0	39.0	2331.1	6551.1	7814.6
1934-35	"	"	"	"	"	"	2243.6	1929.7	2018.1	2041.1	2310.6	3998.2	6358.2	"
1935-36	"	"	"	"	"	"	2242.9	1832.7	1724.8	1669.2	1950.0	4355.5	6997.7	"
1936-37	"	"	"	"	"	"	3363.9	3294.9	3381.6	3489.0	3721.0	5610.0	7516.6	"
1937-38	"	"	"	"	"	"	1466.3	1092.9	982.6	982.8	1106.0	3060.4	6362.2	"
1938-39	"	"	"	"	"	"	3193.4	3124.0	3212.4	3318.1	3575.0	4922.5	7440.3	"
1939-40	"	"	"	"	"	"	3147.9	2984.8	3023.2	3111.6	3409.9	5565.6	7237.6	"
1940-41	"	"	"	"	"	"	3280.0	3236.9	3325.3	3431.0	3679.1	5821.0	7501.3	"
1941-42	"	"	"	"	"	"	3196.2	3166.8	3257.1	3340.1	3402.1	4271.8	6573.3	"
1942-43	"	"	"	"	"	"	2780.4	2398.2	2329.1	2263.5	2651.9	4293.2	6739.3	"
1943-44	"	"	"	"	"	"	3416.4	3296.3	3381.6	3498.2	3745.7	5883.1	7620.6	"
1944-45	"	"	"	"	"	"	3332.3	"	"	"	3733.6	4913.5	7533.3	"
1945-46	"	"	"	"	"	"	887.7	484.0	367.8	344.0	435.6	1755.4	6095.4	"
1946-47	"	"	"	"	"	"	1001.4	651.4	564.0	562.0	678.8	2739.2	6329.9	"
1947-48	"	"	"	"	"	"	950.3	579.7	477.2	449.0	529.3	1989.4	6100.8	"
1948-49	"	"	"	"	"	"	3209.5	2856.8	2806.2	2763.5	3075.0	4814.2	7457.8	"
1949-50	"	"	"	"	"	"	1305.8	895.7	769.6	746.2	839.0	2136.2	5494.7	"
1950-51	"	"	"	"	"	"	1297.0	934.6	840.5	834.9	948.7	2576.1	6385.7	"
1951-52	"	"	"	"	"	"	1703.8	1298.8	1199.0	1168.8	1276.5	3012.9	6554.0	"
1952-53	"	"	"	"	"	"	2057.5	1674.0	1623.3	1583.4	1808.2	3533.6	6531.2	"
1953-54	"	"	"	"	"	"	860.8	485.9	400.5	390.2	474.1	1427.1	5418.3	7797.6
1954-55	"	"	"	"	"	"	1951.6	1652.0	1625.5	1589.3	1878.7	3314.5	5887.9	7791.1
1955-56	"	"	"	"	"	"	1169.0	792.4	678.1	657.2	746.0	2172.2	6160.9	7814.6
1956-57	"	"	"	"	"	"	1337.6	953.7	854.0	845.4	934.8	2164.6	6689.4	"
1957-58	"	"	"	"	"	"	1171.3	800.4	707.1	703.9	809.3	2208.6	6351.5	"

TABLE 11
(English Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2011 - 12 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3416.4	1975.3	1269.1	1084.4	1064.0	2404.2	5861.9	7329.8
1929-30	7610.9	7692.2	6922.7	6011.6	4515.0	3294.3	1203.4	377.4	0.0	71.1	702.0	2186.1	4047.3	6172.6
1930-31	6700.3	6998.0	6563.2	5721.7	4489.7	2817.4	1169.1	212.3	0.0	0.2	1.4	1199.3	2916.8	3963.0
1931-32	3954.5	3820.7	2923.4	2307.6	1431.4	226.1	2.1	0.0	0.0	102.0	357.7	2225.3	5801.9	7640.5
1932-33	7797.1	7814.4	6977.4	6300.4	6075.2	5204.0	3097.6	1452.0	642.1	577.4	706.3	1918.5	5609.2	7674.3
1933-34	7814.6	7814.4	7544.2	7127.1	6394.7	5251.1	3240.4	1623.3	466.9	312.1	887.5	2582.1	4548.2	6115.6
1934-35	6484.1	6707.2	6017.4	5355.0	5415.6	4460.8	2365.0	1936.1	1109.8	861.5	994.8	2593.3	5787.1	7752.6
1935-36	7814.6	7796.7	7416.1	6675.0	5461.1	3978.1	2349.6	1690.8	1272.1	1153.5	1439.5	4355.5	6985.1	7814.6
1936-37	7814.6	7761.2	7157.3	6298.6	4805.4	3310.0	1313.8	498.5	60.7	30.4	31.6	1367.7	3519.7	5262.0
1937-38	5382.3	5428.2	4712.0	4150.5	3778.9	3013.7	1527.6	1045.1	638.2	535.7	670.3	2566.7	5775.0	7629.8
1938-39	7580.6	7589.7	7129.3	6548.3	5576.2	4587.5	3254.6	2758.1	1703.5	1726.4	1886.0	4164.1	5188.2	7288.1
1939-40	7585.0	7681.1	6965.8	6380.2	5388.6	4600.4	3221.2	2813.4	2004.9	2088.1	2428.6	4780.2	5589.4	6715.9
1940-41	6917.9	6985.1	6626.5	6408.7	5325.5	4098.2	2570.1	2194.2	1939.4	2150.6	1507.5	3195.1	3470.1	4565.0
1941-42	4596.3	4597.7	4279.1	4730.2	4329.1	4503.7	3247.8	2156.5	993.7	877.3	983.0	2720.2	5025.0	7444.0
1942-43	7649.6	7733.6	7105.1	6420.4	5757.3	5134.0	2911.4	2398.2	1320.3	1165.4	1407.2	2565.3	4962.2	7452.1
1943-44	7683.6	7814.4	7482.2	7052.8	6200.0	5157.7	3416.4	2161.5	1274.2	1174.8	1174.8	2399.3	3352.1	4118.8
1944-45	4386.1	4406.3	3605.2	3186.2	2397.2	1115.7	603.6	157.3	0.0	0.1	0.3	1673.2	4638.2	6049.2
1945-46	6045.1	5817.5	5098.5	4519.5	3926.7	3044.1	952.7	446.3	48.9	13.7	326.6	1755.4	5845.2	7690.6
1946-47	7814.6	7814.4	7544.2	7074.2	6394.7	5204.0	3013.4	1370.8	564.0	562.0	678.8	2739.2	6319.6	7752.6
1947-48	7814.6	7794.8	7544.2	7127.1	6394.7	5204.0	3062.7	1334.8	477.2	370.6	529.3	1989.4	6100.8	7685.0
1948-49	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3228.9	2826.4	1652.1	1425.4	1536.5	4084.5	6178.1	7139.9
1949-50	7479.1	7553.6	6932.7	6321.3	5966.3	5204.0	3011.8	1341.9	769.6	706.2	811.8	2086.8	5003.3	7814.6
1950-51	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3161.9	1516.7	906.0	900.4	1014.2	2576.1	5576.9	7690.6
1951-52	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3012.9	1309.1	880.2	813.1	1193.0	3012.9	6203.2	7752.6
1952-53	7814.6	7785.7	7302.6	6573.4	5393.0	4163.6	2167.2	1644.3	1206.4	951.4	998.3	2455.8	5726.2	7554.4
1953-54	7649.6	7814.4	7544.2	7127.1	6394.7	5204.0	3072.2	1516.0	400.5	319.7	382.2	1427.1	4935.7	7673.6
1954-55	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3120.1	1667.3	1242.8	1206.5	885.3	1941.1	5052.4	7679.4
1955-56	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3133.7	1380.0	678.3	645.3	746.2	2172.2	6144.3	7752.6
1956-57	7807.9	7814.4	7544.2	7127.1	6394.7	5204.0	3033.1	1384.3	854.0	819.4	934.8	2210.5	5765.8	7118.1
1957-58	7329.9	7421.3	6828.7	6389.2	5440.1	4649.1	2509.1	915.1	595.8	643.4	809.3	2208.6	6348.2	7621.2
Max	7814.6	7814.4	7544.2	7127.1	6394.7	5251.1	3416.4	2826.4	2004.9	2150.6	2428.6	4780.2	6985.1	7814.6
Median	7666.6	7773.5	7143.3	6484.4	5666.8	4891.6	3013.2	1484.0	811.8	759.7	886.4	2401.8	5599.3	7587.8
Average	7147.2	7178.1	6701.0	6189.9	5400.5	4328.5	2513.0	1470.1	832.4	776.3	903.0	2518.5	5275.9	6997.1
Min	3954.5	3820.7	2923.4	2307.6	1431.4	226.1	2.1	0.0	0.0	0.1	0.3	1199.3	2916.8	3963.0

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

	2003-04 2004-05 1/	2005-06	2006-07 through 2008-09 2/	2009-10	2010-11	2011-12
MICA TARGET OPERATION						
(ksfd[xxxx.x] or cfs [xxxxx])						
AUG 15	3499.2	3499.1	3454.2	3454.2	3439.2	3364.2
AUG 31	FULL	FULL	FULL	FULL	FULL	FULL
SEP	FULL	3524.1	FULL	FULL	FULL	FULL
OCT	3374.1	3344.1	3428.4	3428.4	3428.4	3428.4
NOV	20000	23000	20000	22000	21000	21000
DEC	23000	25000	25000	25000	25000	25000
JAN	25000	26000	24000	23000	27000	21000
FEB	21000	22000	21000	20000	21000	21000
MAR	19000	20000	18000	17000	21000	17000
APR 15	204.1	16000	18000	18000	22000	20000
APR 30	15000	13000	12000	11000	10000	10000
MAY	10000	10000	10000	10000	8000	8000
JUN	10000	10000	10000	10000	8000	8000
JUL	3449.2	3449.1	3379.2	3436.2	3467.2	3467.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)						
1928 AUG 31	7808.9	7678.3	7786.1	7811.6	7794.1	7814.4
1928 DEC	5213.8	4938.9	5133.8	5110.5	5086.0	5204.0
1929 APR15	1598.5	927.1	839.3	671.5	1048.2	1084.4
1929 JUL	7280.7	7222	7147.7	7168.9	7233.2	7329.8
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)						
60-Yr Average						
AUG 31	7415.0	7238.3	7360.7	7455.5	7438.0	7362.8
DEC	4759.5	4437.3	4634.9	4640.3	4612.9	4630.0
APR15	1097.7	1085.8	1178.5	877.8	842.6	908.6
JUL	7262.0	7215.5	7193.7	7277.6	7268.9	7147.1
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)						
U.S. Firm Energy	-1.2	-0.1	-0.2	-0.3	-0.3	0.1
U.S. Dependable Peaking Capa	16.0	-51.0	-21.0	-2.7	-19.1	-22.9
U.S. Average Annual Usable Se	12.9	10.5	0.3	13.8	16.0	21.6
BCH Firm Energy	43.1	97.7	90.3	50.2	34.4	43.6
BCH Dependable Peaking Capa	8.0	2.0	11.0	44.9	43.8	41.7
BCH Average Annual Usable Se	-24.3	-55.7	-29.3	-28.2	-20.8	-13.9
COORDINATED HYDRO MODEL LOAD (MW)						
AUG 15	10439	11097	11137	11138	11138	10969
AUG 31	10435	11125	11165	11166	11167	11104
SEP	10101	10809	10849	10850	11025	11081
OCT	10186	9742	9782	9783	9958	9920
NOV	11807	10817	11157	11157	11333	11458
DEC	13377	12853	13192	13193	13369	13316
JAN	13122	12735	13075	13076	13076	12878
FEB	12240	11561	11901	11901	11902	11721
MAR	11175	11275	11315	11316	10967	10501
APR 15	10541	10550	10589	10590	10241	9786
APR 30	13065	14061	12822	12823	12475	11502
MAY	13752	14729	13491	13491	13493	13287
JUN	13114	14039	14079	14079	14080	13867
JUL	12079	12383	12723	12724	12725	12531
ANNUAL AVERAGE	11933	12034	12037	12038	12039	11855

1/ The AOP/DDPB 2004-05 utilize the same system regulation studies as the 2003-04 AOP/DDPB.

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

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2011-12 ASSURED OPERATING PLAN

		Target Operation		Target Operation Limits		
Month	End of Previous Month **Arrow** Storage Content (hm3)	Month Average Outflow (m^3/s)	End-of-Month Treaty Storage Content 1/ (hm3)	Minimum Treaty Storage Content 2/ (hm^3)	Maximum Outflow 1/ (m^3/s)	Minimum Outflow (m^3/s)
August 1-15	8,073.7 - FULL	-	8,230.8	-	962.77	424.75
	5,309.1 - 8,073.7	707.92	-	0.0	-	424.75
	3,669.9 - 5,309.1	566.34	-	0.0	-	424.75
	0.0 - 3,669.9	906.14	-	0.0	0.00	424.75
August 16-31	6,630.2 - FULL	-	8,634.5	-	962.77	424.75
	4,770.8 - 6,630.2	707.92	-	0.0	-	424.75
	0.0 - 4,770.8	906.14	-	0.0	-	424.75
September	8,636.4 - FULL	-	8,634.5	-	962.77	283.17
	8,318.4 - 8,636.4	679.60	-	0.0	-	283.17
	6,850.4 - 8,318.4	764.55	-	0.0	-	283.17
	0.0 - 6,850.4	906.14	-	0.0	-	283.17
October	8,416.2 - FULL	-	8,387.8	-	962.77	283.17
	6,361.1 - 8,416.2	538.02	-	0.0	-	283.17
	4,893.2 - 6,361.1	622.97	-	0.0	-	283.17
	0.0 - 4,893.2	906.14	-	0.0	-	283.17
November	8,171.6 - FULL	594.65	-	0.0	-	283.17
	7,657.8 - 8,171.6	538.02	-	0.0	-	283.17
	1,027.6 - 7,657.8	707.92	-	0.0	-	283.17
	0.0 - 1,027.6	906.14	-	0.0	-	283.17
December	6,703.6 - FULL	707.92	-	499.3	-	283.17
	4,403.8 - 6,703.6	622.97	-	499.3	-	283.17
	734.0 - 4,403.8	764.55	-	499.3	-	283.17
	0.0 - 734.0	906.14	-	499.3	-	283.17
January	6,459.0 - FULL	679.60	-	499.3	-	339.80
	5,333.5 - 6,459.0	764.55	-	499.3	-	339.80
	3,302.9 - 5,333.5	707.92	-	499.3	-	339.80
	0.0 - 3,302.9	821.19	-	499.3	-	339.80
February	3,351.8 - FULL	594.65	-	0.0	-	339.80
	2,201.9 - 3,351.8	736.24	-	0.0	-	339.80
	1,223.3 - 2,201.9	594.65	-	0.0	-	339.80
	0.0 - 1,223.3	736.24	-	0.0	-	339.80
March	1,957.3 - FULL	481.39	-	0.0	-	339.80
	1,883.9 - 1,957.3	736.24	-	0.0	-	339.80
	1,247.8 - 1,883.9	622.97	-	0.0	-	339.80
	0.0 - 1,247.8	707.92	-	0.0	-	339.80
April 1-15	2,177.5 - FULL	566.34	-	0.0	-	339.80
	856.3 - 2,177.5	283.17	-	0.0	-	339.80
	538.2 - 856.3	339.80	-	0.0	-	339.80
	0.0 - 538.2	622.97	-	0.0	-	339.80
April 16-30	1,394.5 - FULL	283.17	-	0.0	-	283.17
	269.1 - 1,394.5	424.75	-	0.0	-	283.17
	48.9 - 269.1	283.17	-	0.0	-	283.17
	0.0 - 48.9	424.75	-	0.0	-	283.17
May	1,565.8 - FULL	226.53	-	0.0	-	226.53
	1,272.2 - 1,565.8	339.80	-	0.0	-	226.53
	538.2 - 1,272.2	226.53	-	0.0	-	226.53
	0.0 - 538.2	283.17	0	0.0	-	226.53
June	3,939.0 - FULL	226.53	-	0.0	-	226.53
	2,495.5 - 3,939.0	283.17	-	0.0	-	226.53
	1,981.7 - 2,495.5	396.44	0	0.0	-	226.53
	0.0 - 1,981.7	509.70	-	0.0	-	226.53
July	7,780.1 - FULL	-	8,482.8	-	962.77	283.17
	6,532.4 - 7,780.1	-	8,331.1	-	962.77	283.17
	2,838.0 - 6,532.4	566.34	-	0.0	-	283.17
	0.0 - 2,838.0	877.82	-	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
2011-12 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	-	283.2
		>75 to <86	URC to 2447		
		≥ 86	2447		
May	1 May - 31 Jul	≤ 84	URC	-	283.2
		>84 to <86	URC to 5138		
		≥ 86	5138		
June	1 Jun - 31 Jul	≤ 41	URC	-	141.6
		>41 to <43	URC to 8318		
		≥ 43	8318		
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 2011-12 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	283.2	283.2	141.6	283.2
End-of-Period Maximum Storage Limits (hm^3)									
1928-29	-	-	URC	URC	URC	URC	URC	8563.7	-
1929-30	-	-	URC	URC	URC	URC	URC	URC	-
1930-31	-	-	URC	URC	URC	URC	URC	URC	-
1931-32	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1932-33	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1933-34	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1934-35	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1935-36	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	8510.7	-
1937-38	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1938-39	-	-	4719.0	2276.3	2845.9	3038.2	URC	URC	-
1939-40	-	-	4862.3	2942.7	4729.5	4820.2	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1942-43	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	4532.8	2365.6	2506.5	2726.0	URC	8318.4	-
1945-46	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1946-47	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1947-48	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1948-49	-	-	4403.8	2201.9	2201.9	2446.6	7203.2	URC	-
1949-50	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1950-51	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1951-52	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1952-53	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1953-54	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	URC	-
1954-55	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1955-56	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1956-57	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1957-58	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2011 - 12 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	8618.3	8340.4	7346.8	5563.8	3735.4	1917.4	1235.8	632.9	424.5	1147.4	5173.8	7587.3
1929-30	8309.5	8573.3	8142.2	6045.2	4787.5	3501.0	1254.6	392.7	0.0	0.0	538.7	1525.9	2860.5	6053.8
1930-31	7004.3	7771.3	7785.0	5999.2	5107.7	3024.7	1826.4	164.9	0.0	0.0	0.0	654.2	2313.2	5122.9
1931-32	4904.2	4487.8	2831.4	2603.6	1498.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	8757.8	8757.3	8129.5	7420.2	6779.0	6091.2	3749.6	2280.5	1466.0	1677.6	1808.5	4077.0	7837.8	8692.4
1929-30	8658.7	8650.8	7342.9	7217.6	4930.1	3574.2	1152.8	420.3	0.0	171.3	1095.1	3555.9	6270.3	7996.9
1930-31	8242.8	8070.0	6850.7	6680.1	4530.8	3052.1	683.3	354.5	0.0	0.0	3.4	1895.4	4454.0	4232.3
1931-32	4351.2	4623.3	4113.9	2763.9	1834.2	553.2	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	1726.8	1726.8	1709.7	1676.4	1519.3	1077.0	873.4	634.9	403.2	342.5	370.2	657.6	1330.0	1653.2
1929-30	1652.4	1595.4	1451.8	1444.9	1328.7	984.5	536.8	110.3	0.0	2.7	83.7	266.7	771.2	1051.0
1930-31	1145.7	1279.8	1421.7	1319.2	1345.9	816.2	350.6	0.0	0.0	0.5	0.0	384.6	368.9	340.6
1931-32	419.3	236.3	207.0	278.2	169.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	19119.0	19118.5	18457.5	17437.0	15645.1	12732.0	8358.5	4832.7	3104.9	2653.1	2603.2	5882.1	14341.6	17932.9
1929-30	18620.6	18819.5	16936.9	14707.8	11046.3	8059.8	2944.2	923.3	0.0	174.0	1717.5	5348.5	9902.0	15101.7
1930-31	16392.8	17121.1	16057.4	13998.6	10984.4	6893.0	2860.3	519.4	0.0	0.5	3.4	2934.2	7136.2	9695.8
1931-32	9674.7	9347.4	7152.3	5645.7	3502.0	553.2	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: These rule curves are input to the AOP 2012 Step 1 study.
They will be adjusted to eliminate any Canadian composite crossovers according to 3 a) of the AOP document.

TABLE 4M
(Metric Units)
MICA
ASSURED AND VARIABLE REFILL CURVES,
DISTRIBUTION FACTORS AND FORECAST ERRORS,
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2011 - 12 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	125.8	1551.9	3025.7	3462.6	3622.4	3662.8	3650.0	3621.9	3638.5	3699.7	3854.3	5755.6	8528.8	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							6751.1	6316.6	6169.0	6148.5	6248.6	7475.3	8203.4	8634.5
1929-30							4249.9	3719.5	3548.3	3571.8	3954.6	5992.2	7509.0	"
1930-31							4880.7	4372.3	4190.0	4160.4	4381.3	6038.6	7691.8	"
1931-32							2327.4	1836.6	1670.5	1642.9	1929.9	3859.0	6966.9	"
1932-33							2098.9	1694.5	1570.9	1537.9	1728.0	3611.6	6569.1	"
1933-34							99.1	0.0	0.0	0.0	2.0	2990.2	7184.4	"
1934-35							3031.1	2580.9	2487.2	2503.3	2674.8	4388.4	6841.4	"
1935-36							2654.3	2205.3	2084.0	2050.2	2282.7	4412.6	7522.5	"
1936-37							6718.5	6233.9	6049.9	6002.7	6220.4	7504.9	8280.4	"
1937-38							3009.8	2559.9	2394.0	2377.3	2604.9	4407.5	7191.5	"
1938-39							4171.4	3830.1	3681.9	3715.4	3987.4	5863.5	8191.1	"
1939-40							3653.2	3222.1	3116.4	3135.3	3452.1	5382.5	7609.8	"
1940-41							5333.5	4875.3	4740.7	4758.6	5191.6	6964.2	8236.9	"
1941-42							4280.5	3831.8	3677.2	3638.3	3824.5	5436.5	7653.1	"
1942-43							4568.2	4063.8	3901.8	3862.4	4235.3	5942.7	7774.0	"
1943-44							6977.1	6453.8	6303.1	6278.2	6446.0	7773.3	8622.2	"
1944-45							6430.6	5997.8	5881.1	5882.1	6003.4	7224.2	8315.2	"
1945-46							1594.2	1070.1	899.9	841.6	1065.7	3120.6	6956.8	"
1946-47							1872.4	1479.7	1379.9	1375.0	1660.7	3758.4	7123.7	"
1947-48							1747.3	1304.3	1167.5	1098.5	1295.0	3258.1	6846.5	"
1948-49							5898.2	5392.7	5189.9	5149.8	5339.4	6624.3	8634.5	"
1949-50							2617.1	2077.4	1882.9	1825.6	2033.1	3799.3	6384.8	"
1950-51							2595.6	2172.6	2056.3	2042.6	2321.1	4090.7	7269.3	"
1951-52							3590.8	3063.6	2885.0	2813.8	3013.9	4813.4	7629.6	"
1952-53							4279.1	3795.4	3640.0	3600.4	3746.4	5193.1	7548.9	"
1953-54							1528.4	1074.8	979.9	954.7	1159.9	3053.1	6316.6	"
1954-55							3387.3	2972.6	2857.6	2848.8	3060.4	4632.8	6792.4	"
1955-56							2282.4	1824.7	1659.0	1607.9	1825.1	3841.1	7060.3	"
1956-57							2694.9	2219.3	2089.4	2068.3	2287.1	4051.8	7868.9	"
1957-58							2288.0	1844.2	1730.0	1722.1	1980.0	3799.3	7288.1	"
DISTRIBUTION FACTORS							0.9750	0.9770	0.9740	0.9812	0.9650	0.7950	0.4950	N/A
FORECAST ERRORS (hm^3)							1781.4	1276.9	1113.9	1028.3	1028.3	982.3	971.5	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	632.9	1560.3
VARIABLE REFILL CURVES					98.68 km^3		84.95	84.95	84.95	84.95	84.95	84.95	906.14	1076.04
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		84.95	84.95	84.95	84.95	84.95	84.95	509.70	914.63
					135.69 km^3		84.95	84.95	84.95	84.95	84.95	84.95	509.70	914.63
OPERATING RULE CURVE LOWER LIMITS (hm^3)							684.6	69.7	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
2011 - 12 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	1704.0	3642.5	3807.9	4007.5	4204.9	4617.9	7576.1	8757.8	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							8757.8	8512.1	8225.4	8036.5	8324.7	8757.8	8663.6	8757.8
1929-30							5153.0	4468.9	4478.5	4471.6	5208.3	8180.9	8757.8	"
1930-31							6384.1	5630.3	5393.7	5285.3	5781.5	7823.4	8710.1	"
1931-32							0.0	0.0	0.0	0.0	0.0	1190.3	6615.1	"
1932-33							"	"	"	"	"	1069.9	6343.5	"
1933-34							"	"	"	"	"	2123.4	7530.3	"
1934-35							2266.8	2093.8	2361.2	2400.6	2829.2	5512.9	7568.2	"
1935-36							2641.8	2232.0	2120.2	2020.9	2407.9	5715.2	8311.0	"
1936-37							8757.8	8757.8	8757.8	8587.5	8757.8	8757.8	8757.8	"
1937-38							0.0	0.0	0.0	0.0	0.0	2564.5	7164.6	"
1938-39							5299.5	4666.1	4457.2	4348.3	5034.1	7627.2	8757.8	"
1939-40							4245.3	3985.5	4105.8	4301.1	4957.7	7486.5	"	"
1940-41							7934.0	7301.6	7157.5	7348.5	8395.9	8757.8	"	"
1941-42							5776.6	5155.7	5031.6	4906.1	5532.2	8046.8	8570.4	"
1942-43							2759.5	1972.2	1785.3	1623.1	2478.4	5620.0	8473.5	"
1943-44							8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	"
1944-45							"	8418.4	8224.4	8105.3	8383.2	"	"	"
1945-46							0.0	0.0	0.0	0.0	0.0	924.6	6821.3	"
1946-47							"	"	"	"	"	2583.6	7203.7	"
1947-48							"	"	"	"	"	1207.9	6886.1	"
1948-49							3661.1	2953.0	2819.7	2720.8	3355.7	5196.5	8359.5	"
1949-50							0.0	0.0	0.0	0.0	0.0	1214.0	6019.3	"
1950-51							"	"	"	"	"	1889.0	7237.9	"
1951-52							"	"	"	"	"	2006.4	7168.0	"
1952-53							1107.1	427.2	324.9	227.8	720.0	3404.7	7281.0	"
1953-54							0.0	0.0	0.0	0.0	0.0	288.5	6626.3	"
1954-55							1196.1	1022.7	1119.3	1039.5	1536.0	5130.5	6627.8	"
1955-56							0.0	0.0	0.0	0.0	0.0	1198.3	6894.9	"
1956-57							"	"	"	"	"	846.3	7216.4	"
1957-58							"	"	"	"	"	1353.9	7084.5	"
DISTRIBUTION FACTORS							0.9710	0.9747	0.9691	0.9741	0.9530	0.7483	0.4631	N/A
FORECAST ERRORS (hm^3)							3634.4	2680.2	2335.3	1981.5	1981.5	1769.9	1662.4	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	1714.59	2524.16
VARIABLE REFILL CURVES					98.68	km^3	141.58	141.58	141.58	141.58	141.58	141.58	1874.58	1959.53
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	141.58	141.58	141.58	141.58	141.58	141.58	1217.62	1614.06
					135.69	km^3	141.58	141.58	141.58	141.58	141.58	141.58	141.58	1311.07
OPERATING RULE CURVE LOWER LIMITS (hm^3)							386.3	67.5	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
2011 - 12 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	90.3	238.1	400.3	475.1	518.2	545.3	570.3	592.8	627.3	654.0	691.9	1061.8	1357.8	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							902.1	859.0	880.8	872.9	913.6	1065.2	1416.1	1726.8
1929-30							898.1	854.1	875.1	866.6	925.8	1115.4	1444.2	"
1930-31							762.4	721.5	751.3	755.0	810.6	991.8	1416.1	"
1931-32							0.0	0.0	0.0	0.0	0.0	395.1	1141.3	"
1932-33							"	"	"	"	"	0.0	810.8	"
1933-34							"	"	"	"	93.5	589.6	1313.1	"
1934-35							56.0	31.1	89.1	89.8	149.0	520.9	1146.2	"
1935-36							24.5	0.0	15.7	12.7	80.2	528.2	1286.9	"
1936-37							745.0	699.7	726.1	718.3	769.7	955.1	1371.3	"
1937-38							0.0	0.0	10.0	27.2	101.0	515.5	1209.6	"
1938-39							327.8	300.2	333.2	338.1	415.9	740.3	1372.3	"
1939-40							298.7	282.8	334.7	363.1	447.2	749.1	1339.7	"
1940-41							539.7	517.2	558.8	591.6	702.9	965.7	1402.9	"
1941-42							334.7	318.1	359.4	365.0	436.7	763.3	1314.3	"
1942-43							307.5	273.3	311.2	312.9	407.8	780.5	1278.3	"
1943-44							917.2	885.4	918.2	915.3	973.0	1131.8	1490.2	"
1944-45							667.7	636.4	672.1	670.4	714.9	921.1	1377.4	"
1945-46							0.0	0.0	0.0	0.0	0.0	249.6	1134.7	"
1946-47							"	"	"	"	"	359.6	1159.2	"
1947-48							"	"	"	"	"	401.2	1193.4	"
1948-49							455.8	414.4	444.1	438.4	500.3	826.2	1440.8	"
1949-50							0.0	0.0	0.0	0.0	19.6	410.5	1039.1	"
1950-51							"	"	"	"	0.0	322.9	1115.9	"
1951-52							39.6	3.9	48.4	45.8	109.1	551.5	1237.2	"
1952-53							34.0	5.1	44.8	"	102.0	490.0	1149.2	"
1953-54							0.0	0.0	0.0	0.0	0.0	150.0	979.4	"
1954-55							"	"	"	"	"	359.2	985.0	"
1955-56							"	"	"	"	"	275.0	1117.8	"
1956-57							"	"	"	"	"	397.8	1280.8	"
1957-58							"	"	"	"	"	250.3	1166.8	"
DISTRIBUTION FACTORS							0.9720	0.9790	0.9740	0.9790	0.9570	0.7580	0.4690	N/A
FORECAST ERRORS (hm^3)							312.4	255.2	256.9	229.5	229.5	212.6	190.8	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	8.30	113.18	69.55
VARIABLE REFILL CURVES					98.68 km^3		2.83	2.83	2.83	2.83	2.83	39.64	50.97	50.97
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		2.83	2.83	2.83	2.83	2.83	2.83	16.99	31.15
					135.69 km^3		2.83	2.83	2.83	2.83	2.83	2.83	16.99	28.32
OPERATING RULE CURVE LOWER LIMITS (hm^3)							191.3	46.5	0.0	0.0				

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2011 - 12 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	8387.8	8387.8	8151.0	7836.4	7550.1	7239.2	7239.2	7239.2	7506.8	8634.5	8634.5
1929-30	"	"	"	"	"	"	7699.4	7289.1	6828.9	6828.9	6828.9	6907.2	7947.5	"
1930-31	"	"	"	"	"	"	8151.0	8151.0	8151.0	8151.0	8151.0	8151.0	8634.5	"
1931-32	"	"	"	"	"	"	6584.5	5168.4	3601.8	3601.8	3601.8	5624.9	8287.3	"
1932-33	"	"	"	"	"	"	"	"	"	"	"	4064.7	7019.0	"
1933-34	"	"	"	"	"	"	"	"	"	"	4497.5	6711.9	7869.4	"
1934-35	"	"	"	"	"	"	"	"	"	"	3601.8	4694.0	7029.0	"
1935-36	"	"	"	"	"	"	"	"	"	"	3808.1	6651.5	8634.5	"
1936-37	"	"	"	"	"	"	7612.5	7114.9	6580.6	6580.6	6580.6	6851.9	8274.3	"
1937-38	"	"	"	"	"	"	6584.5	5168.4	3601.8	3601.8	3702.4	5645.0	7960.2	"
1938-39	"	"	"	"	"	"	6940.7	5835.8	4634.3	4634.3	4799.2	7741.2	8087.6	"
1939-40	"	"	"	"	"	"	7326.3	6555.6	5724.3	5724.3	5724.3	7619.9	8160.1	"
1940-41	"	"	"	"	"	"	8122.9	8097.7	8072.7	8072.7	8072.7	8170.3	8309.5	"
1941-42	"	"	"	"	"	"	6584.5	5168.4	3601.8	3601.8	3601.8	4784.5	8025.5	"
1942-43	"	"	"	"	"	"	"	"	"	"	"	4291.3	6928.5	"
1943-44	"	"	"	"	"	"	8151.0	8151.0	8151.0	8151.0	8151.0	8344.3	8634.5	"
1944-45	"	"	"	"	"	"	6915.7	5811.1	4584.9	4584.9	4584.9	5861.5	,,	"
1945-46	"	"	"	"	"	"	6584.5	5168.4	3601.8	3601.8	3601.8	6631.4	8065.9	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	6203.8	8634.5	"
1947-48	"	"	"	"	"	"	"	"	"	"	"	5695.4	"	"
1948-49	"	"	"	"	"	"	"	"	"	"	3667.2	5947.1	8624.4	"
1949-50	"	"	"	"	"	"	"	"	"	"	3601.8	3601.8	6671.8	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	6042.6	7633.1	"
1951-52	"	"	"	"	"	"	"	"	"	"	3782.9	6113.0	7949.9	"
1952-53	"	"	"	"	"	"	"	"	"	"	3601.8	4779.4	7607.9	"
1953-54	"	"	"	"	"	"	"	"	"	"	,,	4558.0	5730.6	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	3601.8	7159.9	8604.4
1955-56	"	"	"	"	"	"	"	"	"	"	"	5589.7	8030.6	8634.5
1956-57	"	"	"	"	"	"	"	"	"	"	"	7340.9	8634.5	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6299.2	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2011 - 12 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	8449.5	8449.5	7887.0	7800.7	7722.9	7636.7	7636.7	7636.7	7880.2	8757.8	8757.8
1929-30	"	"	"	"	"	"	7668.5	7471.4	7253.1	7253.1	7253.1	7253.1	"	"
1930-31	"	"	"	"	"	"	7887.0	7887.0	7887.0	7887.0	7887.0	8757.8	"	"
1931-32	"	"	"	"	"	"	6670.6	5533.4	4317.2	4317.2	4317.2	5773.7	"	"
1932-33	"	"	"	"	"	"	6657.1	5546.9	"	"	"	4317.2	7856.4	"
1933-34	"	"	"	"	"	"	"	"	"	"	5263.1	5982.4	8757.8	"
1934-35	"	"	"	"	"	"	"	"	"	"	4317.2	4983.2	,,	"
1935-36	"	"	"	"	"	"	6670.6	5533.4	"	"	5334.0	7070.4	"	"
1936-37	"	"	"	"	"	"	7586.1	7314.8	7013.8	7013.8	7013.8	7045.6	"	"
1937-38	"	"	"	"	"	"	6657.1	5546.9	4317.2	4317.2	4317.2	5072.0	"	"
1938-39	"	"	"	"	"	"	6963.0	6128.2	5204.1	5204.1	5204.1	5547.4	"	"
1939-40	"	"	"	"	"	"	7311.3	6791.7	6216.3	6216.3	6216.3	7635.8	"	"
1940-41	"	"	"	"	"	"	7887.0	7887.0	7887.0	7887.0	7887.0	8151.3	"	"
1941-42	"	"	"	"	"	"	6657.1	5546.9	4317.2	4317.2	4317.2	4903.4	7114.6	"
1942-43	"	"	"	"	"	"	"	"	"	"	5600.5	6390.9	8757.8	"
1943-44	"	"	"	"	"	"	7887.0	7887.0	7887.0	7887.0	7887.0	8066.4	"	"
1944-45	"	"	"	"	"	"	6948.8	6101.3	5163.0	5163.0	5163.0	5344.5	"	"
1945-46	"	"	"	"	"	"	6657.1	5546.9	4317.2	4317.2	4317.2	4730.2	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	5458.3	"	"
1947-48	"	"	"	"	"	"	6670.6	5533.4	"	"	"	5089.9	"	"
1948-49	"	"	"	"	"	"	6657.1	5546.9	"	"	"	7318.9	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	4317.2	6413.2	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	5156.4	8757.8	"
1951-52	"	"	"	"	"	"	6670.6	5533.4	"	"	4770.1	6666.2	"	"
1952-53	"	"	"	"	"	"	6657.1	5546.9	"	"	4317.2	4317.2	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	5334.0	6546.3	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	4330.4	6706.3	"
1955-56	"	"	"	"	"	"	6670.6	5533.4	"	"	4694.7	6426.4	8757.8	"
1956-57	"	"	"	"	"	"	6657.1	5546.9	"	"	4317.2	6519.6	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6599.6	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2011 - 12 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	1066.7	1602.8	"
1930-31	"	"	"	"	"	"	955.9	705.3	705.3	705.3	716.6	1062.3	1605.4	"
1931-32	"	"	"	"	"	"	669.6	160.3	160.3	160.3	160.3	674.3	1533.3	"
1932-33	"	"	"	"	"	"	"	"	"	"	"	325.4	1204.7	1686.9
1933-34	"	"	"	"	"	"	"	"	"	"	1246.0	1480.7	1681.3	1726.8
1934-35	"	"	"	"	"	"	"	"	"	"	160.3	410.3	1188.1	"
1935-36	"	"	"	"	"	"	"	"	"	"	255.2	823.8	1615.2	"
1936-37	"	"	"	"	"	"	917.0	631.5	631.5	631.5	631.5	924.1	1520.3	"
1937-38	"	"	"	"	"	"	709.8	236.8	236.8	236.8	286.2	718.8	1544.8	"
1938-39	"	"	"	"	"	"	697.5	213.3	213.3	213.3	274.3	826.5	1366.4	"
1939-40	"	"	"	"	"	"	728.6	272.5	272.5	272.5	272.5	747.7	1425.1	"
1940-41	"	"	"	"	"	"	842.6	489.6	489.6	489.6	528.9	909.9	1516.6	"
1941-42	"	"	"	"	"	"	797.8	404.4	404.4	404.4	404.4	775.1	1323.6	"
1942-43	"	"	"	"	"	"	805.7	419.3	419.3	419.3	419.3	592.3	1086.3	"
1943-44	"	"	"	"	"	"	1005.8	800.5	800.5	800.5	800.5	1077.5	1644.6	"
1944-45	"	"	"	"	"	"	933.4	662.3	662.3	662.3	662.3	963.2	1598.8	"
1945-46	"	"	"	"	"	"	669.6	160.3	160.3	160.3	179.1	800.0	1658.5	"
1946-47	"	"	"	"	"	"	"	"	"	"	203.3	767.7	1560.4	"
1947-48	"	"	"	"	"	"	"	"	"	"	160.3	611.6	1610.6	"
1948-49	"	"	"	"	"	"	900.3	599.4	599.4	599.4	647.4	1188.5	1726.8	"
1949-50	"	"	"	"	"	"	669.6	160.3	160.3	160.3	160.3	444.1	1306.2	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	1291.5	1484.3	"
1951-52	"	"	"	"	"	"	"	"	"	"	233.4	722.2	1456.4	"
1952-53	"	"	"	"	"	"	"	"	"	"	160.3	461.2	1197.8	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	464.1	1066.5	1685.2
1954-55	"	"	"	"	"	"	"	"	"	"	"	176.9	"	1699.4
1955-56	"	"	"	"	"	"	"	"	"	"	"	785.8	1557.5	1726.8
1956-57	"	"	"	"	"	"	"	"	"	"	175.4	921.1	1692.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	160.3	818.9	1671.3	"

TABLE 10M
(Metric Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2011 - 12 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.0	19118.5	18457.5	17437.0	15645.1	12732.0	8358.5	8064.6	8273.3	8558.6	9164.1	14389.5	18224.8	19119.0
1929-30	"	"	"	"	"	"	"	"	8183.1	8430.7	"	14070.5	17624.6	"
1930-31	"	"	"	"	"	"	8247.4	"	8273.3	8558.6	"	14323.5	17759.7	"
1931-32	"	"	"	"	"	"	2905.1	1950.7	1670.5	1642.9	1929.9	5444.4	14723.2	"
1932-33	"	"	"	"	"	"	2676.6	1808.5	1570.9	1537.9	1728.0	4681.5	13723.3	19079.1
1933-34	"	"	"	"	"	"	1262.2	183.7	0.0	0.0	95.4	5703.2	16027.8	19119.0
1934-35	"	"	"	"	"	"	5489.1	4721.2	4937.4	4993.7	5653.1	9781.9	15555.8	"
1935-36	"	"	"	"	"	"	5487.4	4483.8	4219.9	4083.8	4770.8	10656.1	17120.4	"
1936-37	"	"	"	"	"	"	8230.0	8061.2	8273.3	8536.1	9103.7	13725.3	18389.9	"
1937-38	"	"	"	"	"	"	3587.4	2673.9	2404.0	2404.5	2705.9	7487.5	15565.6	"
1938-39	"	"	"	"	"	"	7812.9	7643.1	7859.4	8118.0	8746.5	12043.3	18203.3	"
1939-40	"	"	"	"	"	"	7701.6	7302.5	7396.5	7612.8	8342.6	13616.7	17707.3	"
1940-41	"	"	"	"	"	"	8024.8	7919.3	8135.6	8394.2	9001.2	14241.5	18352.5	"
1941-42	"	"	"	"	"	"	7819.7	7747.8	7968.7	8171.8	8323.5	10451.3	16082.1	"
1942-43	"	"	"	"	"	"	6802.5	5867.4	5698.3	5537.8	6488.1	10503.6	16488.2	"
1943-44	"	"	"	"	"	"	8358.5	8064.6	8273.3	8558.6	9164.1	14393.4	18644.4	"
1944-45	"	"	"	"	"	"	8152.7	"	"	"	9134.5	12021.2	18430.8	"
1945-46	"	"	"	"	"	"	2171.8	1184.1	899.9	841.6	1065.7	4294.7	14912.9	"
1946-47	"	"	"	"	"	"	2450.0	1593.7	1379.9	1375.0	1660.7	6701.7	15486.6	"
1947-48	"	"	"	"	"	"	2325.0	1418.3	1167.5	1098.5	1295.0	4867.2	14926.1	"
1948-49	"	"	"	"	"	"	7852.3	6989.4	6865.6	6761.1	7523.2	11778.3	18246.1	"
1949-50	"	"	"	"	"	"	3194.7	2191.4	1882.9	1825.6	2052.7	5226.4	13443.2	"
1950-51	"	"	"	"	"	"	3173.2	2286.6	2056.3	2042.6	2321.1	6302.6	15623.1	"
1951-52	"	"	"	"	"	"	4168.5	3177.6	2933.4	2859.6	3123.1	7371.3	16034.9	"
1952-53	"	"	"	"	"	"	5033.8	4095.6	3971.5	3873.9	4423.9	8645.2	15979.1	"
1953-54	"	"	"	"	"	"	2106.0	1188.8	979.9	954.7	1159.9	3491.5	13256.3	19077.4
1954-55	"	"	"	"	"	"	4774.7	4041.7	3976.9	3888.3	4596.4	8109.2	14405.2	19061.5
1955-56	"	"	"	"	"	"	2860.0	1938.7	1659.0	1607.9	1825.1	5314.5	15073.1	19119.0
1956-57	"	"	"	"	"	"	3272.5	2333.3	2089.4	2068.3	2287.1	5295.9	16366.1	"
1957-58	"	"	"	"	"	"	2865.7	1958.2	1730.0	1722.1	1980.0	5403.5	15539.4	"

TABLE 11M
(Metric Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2011 - 12 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119	19119	18458	17437	15645	12732	8358.6	4832.8	3105	2653.1	2603.2	5882.1	14342	17933
1929-30	18621	18820	16937	14708	11046	8059.8	2944.2	923.35	0	173.95	1717.5	5348.5	9902.1	15102
1930-31	16393	17121	16058	13999	10985	6893.1	2860.3	519.41	0	0.4893	3.4252	2934.2	7136.2	9695.9
1931-32	9675.1	9347.7	7152.4	5645.8	3502.1	553.18	5.1379	0	0	249.55	875.15	5444.4	14195	18693
1932-33	19076	19119	17071	15415	14864	12732	7578.6	3552.5	1571	1412.7	1728	4693.8	13723	18776
1933-34	19119	19119	18458	17437	15645	12847	7928	3971.6	1142.3	763.58	2171.4	6317.4	11128	14962
1934-35	15864	16410	14722	13102	13250	10914	5786.2	4736.9	2715.2	2107.7	2433.9	6344.8	14159	18968
1935-36	19119	19075	18144	16331	13361	9732.8	5748.5	4136.7	3112.3	2822.2	3521.9	10656	17090	19119
1936-37	19119	18989	17511	15410	11757	8098.2	3214.3	1219.6	148.51	74.377	77.313	3346.2	8611.3	12874
1937-38	13168	13281	11528	10155	9245.5	7373.3	3737.4	2556.9	1561.4	1310.6	1640	6279.7	14129	18667
1938-39	18547	18569	17443	16021	13643	11224	7962.7	6748	4167.8	4223.8	4614.3	10188	12693	17831
1939-40	18557	18793	17043	15610	13184	11255	7881	6883.3	4905.2	5108.7	5941.8	11695	13675	16431
1940-41	16925	17090	16212	15680	13029	10027	6288	5368.3	4744.9	5261.7	3688.2	7817.1	8489.9	11169
1941-42	11245	11249	10469	11573	10592	11019	7946.1	5276.1	2431.2	2146.4	2405	6655.2	12294	18212
1942-43	18716	18921	17383	15708	14086	12561	7123	5867.4	3230.2	2851.3	3442.9	6276.3	12141	18232
1943-44	18799	19119	18306	17255	15169	12619	8358.6	5288.3	3117.5	2874.3	2874.3	5870.1	8201.2	10077
1944-45	10731	10780	8820.5	7795.4	5865	2729.7	1476.8	384.85	0	0.2447	0.734	4093.7	11348	14800
1945-46	14790	14233	12474	11057	9607.1	7447.7	2330.9	1091.9	119.64	33.518	799.06	4294.8	14301	18816
1946-47	19119	19119	18458	17308	15645	12732	7372.6	3353.8	1379.9	1375	1660.8	6701.7	15462	18968
1947-48	19119	19071	18458	17437	15645	12732	7493.2	3265.7	1167.5	906.71	1295	4867.3	14926	18802
1948-49	19119	19119	18458	17437	15645	12732	7899.8	6915.1	4042	3487.4	3759.2	9993.1	15115	17468
1949-50	18298	18481	16962	15466	14597	12732	7368.7	3283.1	1882.9	1727.8	1986.1	5105.6	12241	19119
1950-51	19119	19119	18458	17437	15645	12732	7735.9	3710.8	2216.6	2202.9	2481.3	6302.7	13644	18816
1951-52	19119	19119	18458	17437	15645	12732	7371.4	3202.8	2153.5	1989.3	2918.8	7371.4	15177	18968
1952-53	19119	19048	17867	16082	13195	10187	5302.3	4022.9	2951.6	2327.7	2442.4	6008.4	14010	18483
1953-54	18716	19119	18458	17437	15645	12732	7516.4	3709	979.86	782.18	935.09	3491.5	12076	18774
1954-55	19119	19119	18458	17437	15645	12732	7633.6	4079.2	3040.6	2951.8	2166	4749.1	12361	18788
1955-56	19119	19119	18458	17437	15645	12732	7666.9	3376.3	1659.5	1578.8	1825.7	5314.5	15033	18968
1956-57	19103	19119	18458	17437	15645	12732	7420.8	3386.8	2089.4	2004.7	2287.1	5408.2	14107	17415
1957-58	17933	18157	16707	15632	13310	11374	6138.8	2238.9	1457.7	1574.1	1980	5403.6	15532	18646
Max	19119	19119	18458	17437	15645	12847	8359	6915	4905	5262	5942	11695	17090	19119
Median	18757	19019	17477	15865	13864	11968	7372	3631	1986	1859	2169	5876	13699	18564
Average	17486	17562	16395	15144	13213	10590	6148	3597	2036	1899	2209	6162	12908	17119
Min	9675	9348	7152	5646	3502	553	5	0	0	0	1	2934	7136	9696

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

	2003-04 2004-05 1/	2005-06	2006-07 through 2008-09 2/	2009-10	2010-11	2010-12
MICA TARGET OPERATION						
(hm^3 [xxxx.x] or m^3/s [xxxx.xx])						
AUG 15	8561.1	8560.9	8451.0	8451.0	8414.3	8230.9
AUG 31	FULL	FULL	FULL	FULL	FULL	FULL
SEP	FULL	8622.1	FULL	FULL	FULL	FULL
OCT	8255.1	8181.7	8387.9	8387.9	8387.9	8387.9
NOV	566.3	651.3	566.3	623.0	594.7	594.7
DEC	651.3	707.9	707.9	707.9	707.9	707.9
JAN	707.9	736.2	679.6	651.3	764.6	594.7
FEB	594.7	623.0	594.7	566.3	594.7	594.7
MAR	538.0	566.3	509.7	481.4	594.7	481.4
APR 15	499.4	453.1	509.7	509.7	623.0	566.3
APR 30	424.8	368.1	339.8	311.5	283.2	283.2
MAY	283.2	283.2	283.2	283.2	226.5	226.5
JUN	283.2	283.2	283.2	283.2	226.5	226.5
JUL	8438.8	8438.6	8267.6	8407.0	8482.9	8482.9
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm^3)						
1928 AUG 31	19105.3	18785.7	19049.5	19111.9	19069.0	19118.7
1928 DEC	12756.1	12083.5	12560.4	12503.3	12443.4	12732.1
1929 APR15	3910.9	2268.2	2053.4	1642.9	2564.5	2653.1
1929 JUL	17813.0	17669.3	17487.6	17539.4	17696.7	17933.1
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm^3)						
60-Yr Average						
AUG 31	18141.5	17709.2	18008.7	18240.6	18197.7	18013.8
DEC	11644.6	10856.3	11339.7	11353.0	11286.0	11327.8
APR15	2685.6	2656.5	2883.3	2147.6	2061.6	2222.9
JUL	17767.2	17653.4	17600.1	17805.4	17784.1	17486.1
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)						
U.S. Firm Energy	-1.2	-0.1	-0.2	-0.3	-0.3	0.1
U.S. Dependable Peaking Capa	16.0	-51.0	-21.0	-2.7	-19.1	-22.9
U.S. Average Annual Usable Se	12.9	10.5	0.3	13.8	16.0	21.6
BCH Firm Energy	43.1	97.7	90.3	50.2	34.4	43.6
BCH Dependable Peaking Capa	8.0	2.0	11.0	44.9	43.8	41.7
BCH Average Annual Usable Se	-24.3	-55.7	-29.3	-28.2	-20.8	-13.9
COORDINATED HYDRO MODEL LOAD (MW)						
AUG 15	10439	11097	11137	11138	11138	10969
AUG 31	10435	11125	11165	11166	11167	11104
SEP	10101	10809	10849	10850	11025	11081
OCT	10186	9742	9782	9783	9958	9920
NOV	11807	10817	11157	11157	11333	11458
DEC	13377	12853	13192	13193	13369	13316
JAN	13122	12735	13075	13076	13076	12878
FEB	12240	11561	11901	11901	11902	11721
MAR	11175	11275	11315	11316	10967	10501
APR 15	10541	10550	10589	10590	10241	9786
APR 30	13065	14061	12822	12823	12475	11502
MAY	13752	14729	13491	13491	13493	13287
JUN	13114	14039	14079	14079	14080	13867
JUL	12079	12383	12723	12724	12725	12531
ANNUAL AVERAGE	11933	12034	12037	12038	12039	11855

1/ The 2004-05 AOP/DDPB utilize the same system regulation studies as the 2003-04 AOP/DDPB.

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

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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		Treaty
Arrow (1831)	Minimum Flow	5000 cfs	141.6 m^3/s		Treaty
	Draft Rate Limit	1.0 ft/day	0.30 m/day		CRTOC Agreement
Duncan (1681)	Minimum Flow	100 cfs	2.8 m^3/s		CRTOC Agreement
	Maximum Flow	10000 cfs	283.2 m^3/s		CRTOC Agreement
	Draft Rate Limit	1.0 ft/day	0.30 m/day		CRTOC Agreement
	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 426.3 ksfd 2890.0 ft 0.0 ksfd 2883.0 ft	1503.9 hm^3 881.79 m 1043 hm^3 880.9 m 0 hm^3 878.74 m	Jun - Sep May Empty Apr 15	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80. 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	

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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		

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	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

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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	

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	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.
Other Major Step I Projects					
Libby (1760)	Minimum Flow	4000 cfs	113.3 m^3/s	All periods	
	Other Spill	200 cfs	5.7 m^3/s	All periods	

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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 place 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).			

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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.	
	Start CP at:	642.4 ksfd	1571.7 hm^3	Aug 15	
	End CP at:	218.4 ksfd	534.3 hm^3	Feb	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements Oct-May and meets target operation Jun-Sep to obtain uniform ouflows Jul-Aug			2-1-05 PNCA submittal
	Target Operation:				
		779.3 ksfd	1906.6 hm^3	Jul	2-1-05 PNCA submittal
		1573.2 ft	479.51 m		Jul-Aug 15 and Sep based
		642.4 ksfd	1571.7 hm^3	Aug 15	on 60 Median .
		1555.4 ft	474.09 m		
		490.1 ksfd	1199.1 hm^3	Aug 31	
		1534 ft	467.56 m		
		392.9 ksfd	961.26 hm^3	Sep	
		1519.6 ft	463.16 m		
		1016 ksfd	2485.7 hm^3	Jun	
		1600 ft	487.68 m		
	Other Spill	100 cfs	2.8 m^3/s	All periods	
Lower Granite (520)	Bypass Date			None	
	Other Spill	500 cfs	14.158 m^3/s	Jul - Oct	2-1-05 PNCA submittal
		400 cfs	11.327 m^3/s	Nov - Dec	
		100 cfs	2.8317 m^3/s	Jan	
		200 cfs	5.6634 m^3/s	Feb- Mar	
		460 cfs	13.026 m^3/s	Apr 15 - Jun	
	Incremental Spill			Removed	
	Fish Spill				
		17333 cfs	490.8 m^3/s	Apr 15 [20 kcfs alternating for 13 days]	2-1-06 PNCA submittal
		20000 cfs	566.3 m^3/s	Apr 30 - May	
		19333 cfs	547.4 m^3/s	June [20 kcfs for 20 day and 18 kcfs for 10 days]	
		18000 cfs	509.7 m^3/s	July - Aug 31	

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	Maximum Fish Spill	20000 cfs	566.3 m^3/s	Apr 15 - Jun	
		18000 cfs	509.7 m^3/s	Jul - Aug 31	
	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	600 cfs	17.0 m^3/s	Jul - Nov	2-1-05 PNCA submittal
		450 cfs	12.7 m^3/s	Dec	
		150 cfs	4.2 m^3/s	Jan	
		300 cfs	8.5 m^3/s	Feb - Mar	
		600 cfs	17.0 m^3/s	Apr 15 - Jun	
	Incremental Spill			Removed	
	Fish Spill (% of outflow)	26%		Apr 15 [.30*13/15]	2-1-06 PNCA submittal
		30%		Apr 30 - Aug 31	
	Maximum Fish Spill	25000 cfs	707.9 m^3/s	Apr 15 - Apr 31	
		30000 cfs	849.5 m^3/s	May - Aug 31	
	Minimum Flow	11500 cfs		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	850 cfs	24.1 m^3/s	Jul - Oct	2-1-05 PNCA submittal
		750 cfs	21.2 m^3/s	Nov	
		600 cfs	17.0 m^3/s	Dec	
		300 cfs	8.5 m^3/s	Jan - Feb	
		500 cfs	14.2 m^3/s	Mar	
		850 cfs	24.1 m^3/s	Apr 15 - Jun	
	Fish Spill	19067 cfs	539.9 m^3/s	Apr 15 [22*(13/15)]	2-1-06 PNCA submittal
		22000 cfs	623.0 m^3/s	Apr 31 - May	
		20333 cfs	575.8 m^3/s	Jun [22*(20/30) + 17*(10/30)]	
		17000 cfs	481.4 m^3/s	Jul - Aug 31	

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	Maximum Fish Spill	22000 cfs	623.0 m^3/s	Apr 15 - Jun	
		17000 cfs	481.4 m^3/s	Jul - Aug 31	
	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	100 cfs	2.8 m^3/s	All periods	
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 2011-12
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.

Timothy (117)	Minimum Content	24.5 ksfd	59.9 hm^3	Oct - May	3-6-01 PNCA submittal
		3180.0 ft	969.26 m		
		31.1 ksfd	76.1 hm^3	Jun - Aug 31	
		3190.0 ft	972.31 m		
		27.8 ksfd	68.0 hm^3	Sep [(24.5*15+31.1*15)/30]	
		3185.0 ft	970.79 m		
Long Lake (1305)	Minimum Content	50.1 ksfd	122.6 hm^3	Apr - Nov	2-5-02 PNCA submittal
		1535.0 ft	467.87 m		
		19.7 ksfd	48.2 hm^3	Dec - Mar	
		1522.0 ft	463.9 m		
	Draft Rate Limit	1.0 ft/day	0.30 m/day		2-1-03 PNCA submittal
Priest Lake (1470)	Maximum Content	0.0 ksfd	0.0 hm^3	Oct	2-1-03 PNCA submittal
		0.0 ft	0.00 m		
	Max/Min Content	35.5 ksfd	86.9 hm^3	Maintain at or near after runoff through Sep.	
		3.0 ft	0.91 m		
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries.	2-1-06 PNCA submittal
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 2011-12

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2011-12

March 2007

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 downstream power benefits from the operation of Canadian Treaty Storage be determined in advance by the two Entities. The purpose of this document is to describe the results of the 2011-12 Determination of Downstream Power Benefits (DDPB12) developed from the 2011-12 Assured Operating Plan (AOP12).

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

- 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 16 December 2003, and except for changes noted below, 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.

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 the following changes from the procedures in POP:

- Use only the first of the three Streamline Procedures, "Forecasting Loads and Resources," as described in Appendix 6 of the POP;

- Revise adjustment for Canadian critical rule curve crossovers (see AOP12 subsection 3(a);

- Add Arrow Project Operating Criteria (see AOP12 subsection 4(c)(2));

- Do not include Variable Refill Curve Lower Limits as described in Appendix 1 of POP, but instead at Grand Coulee only, use a fixed Variable Refill Curve Lower Limit as described in subsection 7(f) of the AOP12.; and

- Initialize the Step I power discharge requirements (PDR) at AOP11 levels instead of minimum discharge as described in POP, subsection 2.3.b(3).

The Canadian Entitlement Benefits were computed from the following studies:[1]

Step I -- Operation of the total USA Columbia Basin hydro and thermal system, with 19.12 cubic kilometers (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.

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 DDPB12, 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 3 below, the calculations were not needed for the 2011-12 operating year.

2. 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 computed downstream power benefits, was computed to be (see Table 5 Joint Optimum):

Dependable Capacity	= 1314.0 megawatts (MW)
Average Annual Usable Energy	= 525.9 average annual MW

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

3. Computation of Maximum Allowable Reduction in Downstream Power Benefits

Treaty Annex A, paragraph 7, states 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 2.0 average annual megawatt (aMW) increase in the Energy Entitlement and no change to the Capacity Entitlement (see Table 5, columns A and B), compared to Step II and III studies based on optimum power generation only in the USA. Since there was no reduction in the downstream power benefits in the DDPB12, the computation of the maximum allowable reduction in downstream power benefits, as defined in Section 3.3.A(3) of the POP, was not performed.

4. Delivery of the Canadian Entitlement

See Section 6 of the AOP12.

5. Summary of Information Used for Canadian Entitlement Computations

The following tables and chart summarize the study results:

Table 1A and Table 1B — Determination of Firm Hydro Loads for Step I Studies:

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 was limited to the Thermal Installations with reductions for minimum thermal generation and system sales, which are the thermal resources used to meet load outside the Pacific Northwest Area (PNWA).

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 ratio between each month

and the annual average as the PNWA load. The PNWA firm loads were based on the Bonneville Power Administration (BPA) 2006 White Book (WB06) load forecast, as described in Section 7(a) of the AOP12. 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 Power Regulations from 2011-12 Assured Operating Plan:

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.

Table 5 Computation of Canadian Entitlement for 2011-12 Assured Operating Plan:

A. Joint Optimum Generation in Canada and the USA;
B. Optimum Generation in the USA Only; and
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. The elements for the computation of maximum allowable reduction in downstream power benefits are shown on this table, but are not applicable because that calculation is not necessary as explained in Section 3.

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 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.

6. Summary of Changes from the 2011-12 AOP and Notable Assumptions

Data from recent DDPBs are summarized in Table 6. The following is an explanation of the more important changes and notable assumptions that impact computation of the entitlement compared to the 2010-11 DDPB (DDPB11) studies.

a) Steps II and III Firm Loads

The Steps II and III loads shown on Table 3 are noticeably different than DDPB11, with generally higher levels during July through January and lower levels February through June. The large difference is mainly due to changes in the amount and shape of thermal generation and the changes to hydro plant data.

The average critical period load factor increased from 75.89% in AOP11 (from WB04) to 76.07% in AOP12 (from WB06). This was mainly due to changes in the peak load forecast.

b) Thermal Installations

The Thermal Installation energy capability shown in Table 3 increased by 87.8 annual aMW compared to the DDPB11. This is caused by the changes to loads, CGS maintenance, and non-thermal resources described in Section 7 of the AOP12.

The Thermal Displacement Market (TDM) increased by 189.5 annual aMW, mainly due to the combination of increased thermal installations and the increased amount of Canadian Entitlement assumed to be exported to BC (as described in subsection 7(b) of the AOP12).

c) Hydro Project Modified Streamflows

The base unregulated streamflows used in the Steps II and III System Regulation Studies are the same as the Step I studies (see subsection 7(e) of AOP12), except for adjustments to remove the effect of natural lake regulation, depletions, and evaporation at projects not included in Steps II/III.

d) Hydro Project Rule Curves

The critical rule curves, refill curves, and Mica/Arrow operating criteria were updated in accordance with procedures defined in POP, except for the changes described in subsection 7(f) of the AOP12.

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 AOP12.

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

Step II and Step III critical period regulation studies for the 2011-12 operating year were performed to establish critical period capability as described in Section 2.2.A of the POP. The Step II and Step III critical streamflow periods were the same as the DDPB11 studies. The Step II critical period was the 20 calendar-months from 1 September 1943 through 30 April 1945, and the Step III study critical period was the 5.5 calendar-months from 1 November 1936 through 15 April 1937. Both critical periods saw a significant decrease in average critical period generation (53.6 and 54.6 aMW respectively), mainly due to changes in plant data. However, since the decrease in each Step is almost the same, the effect on the Entitlement is small.

For the 30-year System Regulation Studies, the Entities conducted a full set of Step II (-42, -12, and -22) and Step III (-13) 30-year System Regulation Studies as described in Section 3.3 of the POP.

g) Downstream Power Benefits

The Canadian Capacity Entitlement decreased from 1316.4 MW in the DDPB11 to 1314.0 MW in the DDPB12, a decrease of 2.4 MW. This slight change was mainly due to an increase in the average critical period load factor, from 75.89% to 76.07%.

The Canadian Energy Entitlement decreased from 535.7 aMW in the DDPB11 to 525.9 aMW in the DDPB12 for a decrease of 9.8 aMW. The change was mainly due to the 189.5 annual aMW increase in the TDM and the change in the annual shape of the thermal installation generation. The change in shape was due to no maintenance at the CGS nuclear power plant and use of WB06 thermal resource shape for the Generic Thermal Installation.

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

2 The Step II DDPB12-42 30-year system regulation study dated 26 February 2007 and the Step III DDPB12-13 30-year system regulation study, dated 26 February 2007and prepared by BPA, were used to determine the critical period and 30-year system generation.

TABLE 1A
2011-12 ASSURED OPERATING PLAN
DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES 1/
(Energy in Average MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July	Ann. Avg.	CP Avg.
1. Pacific Northwest Area (PNWA) Firm Load																2/
a) White Book Regional Firm Load 3/	21646	21641	20387	20554	22484	24601	25110	23825	22072	21145	21132	20717	21266	22197	*22166*	*22250*
b) Exclude 99% of UPL's Idaho load 4/	-522	-522	-465	-417	-404	-420	-402	-416	-421	-406	-406	-453	-532	-606	*-455*	*-451*
c) Updates to Coulee pumping 5/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*	*0*
d) ….Total PNWA Firm Loads	**21124**	**21119**	**19921**	**20137**	**22080**	**24181**	**24708**	**23410**	**21651**	**20739**	**20726**	**20263**	**20735**	**21591**	***21711***	***21798***
e) Annual Load Shape in Percent	97.3	97.3	91.8	92.8	101.7	111.4	113.8	107.8	99.7	95.5	95.5	93.3	95.5	99.4	*100.0*	*100.4*
2. Flows-Out of firm power from PNWA																
a) WB06 Exports 6/	931	932	931	824	774	775	774	774	773	802	795	717	886	881	*820*	*820*
b) Remove WB06 Canadian Entitle.	-517	-517	-517	-517	-517	-517	-517	-517	-517	-517	-517	-517	-517	-517	*-517*	*-517*
c) Add est. Can. Entitle. Exported 7/	385	385	385	385	385	385	385	385	385	385	385	385	385	385	*385*	*385*
d) Added Seasonal Exch. export 8/	0	0	1231	0	0	0	0	0	0	0	313	938	3165	1198	*554*	*499*
e) Thermal used out of region 9/	270	299	274	187	136	44	84	127	154	161	141	133	202	224	*167*	*165*
f) …Subtotal for Table 2	1069	1099	2304	879	778	687	726	769	795	831	1117	1656	4121	2171	*1409*	*1352*
g) Remove Plant Sales	-173	-173	-173	-173	-173	-173	-173	-173	-173	-173	-165	-36	-173	-173	*-161*	*-163*
h) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	*-60*	*-59*
i) …Total	**821**	**851**	**2056**	**661**	**560**	**469**	**508**	**551**	**577**	**583**	**877**	**1545**	**3873**	**1923**	***1188***	***1130***
3. Flows-In of firm power to PNWA, except from coordinated thermal installations																
a) WB06 Imports 10/	-737	-708	-694	-697	-805	-929	-886	-864	-783	-734	-727	-680	-781	-864	*-786*	*-789*
b) Exclude UP&L imports for 1(b)	522	522	465	417	404	420	402	416	421	406	406	453	532	606	*455*	*451*
c) Remove Thermal Imports11/	118	90	118	199	251	344	303	259	195	187	207	124	156	161	*201*	*206*
d) Add Seasonal Exch.Imports 8/	-196	-66	0	-93	-261	-508	-1620	-1696	-1650	-1452	0	0	0	0	*-554*	*-565*
e) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	45	45	75	75	75	75	75	*60*	*59*
f) …Total	**-219**	**-87**	**-36**	**-129**	**-366**	**-629**	**-1756**	**-1840**	**-1772**	**-1518**	**-39**	**-28**	**-18**	**-22**	***-624***	***-638***
4. PNWA Non-Step I Hydro and Non-thermal Resources																
a) Hydro Independents (1929 water)	-940	-932	-960	-1035	-1116	-1069	-1025	-855	-954	-1081	-1135	-1457	-1406	-1112	*-1087*	*-968*
b) Non-Step I Coord.Hydro (1929)	-509	-456	-561	-944	-916	-962	-956	-490	-731	-767	-763	-742	-1316	-638	*-792*	*-820*
c) Misc. Wind Resources 12/	-255	-258	-306	-316	-345	-313	-291	-259	-489	-300	-298	-378	-387	-339	*-332*	*-328*
d) Misc. WB06 hydro NUGs	-291	-288	-212	-136	-106	-98	-89	-94	-125	-249	-250	-371	-400	-383	*-213*	*-201*
e) Misc. WB06 Resc.(Renewables)	-18	-18	-18	-18	-17	-18	-18	-18	-18	-18	-18	-18	-18	-18	*-18*	*-18*
f) …Total (1929)	**-2013**	**-1952**	**-2055**	**-2449**	**-2501**	**-2460**	**-2378**	**-1716**	**-2317**	**-2415**	**-2464**	**-2965**	**-3527**	**-2490**	***-2442***	***-2334***
5. Step I System Load (1929) 13/	**19713**	**19932**	**19887**	**18220**	**19774**	**21562**	**21082**	**20404**	**18138**	**17389**	**19100**	**18816**	**21062**	**21002**	***19833***	***19956***
6. Coordinated Thermal Installations 14/																
a) Columbia Gen. Station (WNP2)	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	*1000*	*1000*
b) Generic Thermal Installations	8886	8911	8978	8823	8857	8884	8852	8830	7983	7962	7962	5889	8201	8803	*8410*	*8480*
c) ...Total	**9886**	**9911**	**9978**	**9823**	**9857**	**9884**	**9852**	**9830**	**8983**	**8962**	**8962**	**6889**	**9201**	**9803**	***9410***	***9480***
7. Step I Hydro Resources (1929) 15/	**10460**	**10648**	**10520**	**8976**	**10542**	**12354**	**11922**	**11231**	**9770**	**9019**	**10739**	**12545**	**12551**	**11893**	***11063***	***11116***
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/	-602	-603	-603	-571	-621	-676	-692	-657	-610	-585	-593	-598	-675	-645	*-628*	*-629*
9. Total Step I System Resources(1929)	**19713**	**19932**	**19887**	**18220**	**19774**	**21562**	**21082**	**20404**	**18138**	**17389**	**19100**	**18816**	**21062**	**21002**	***19833***	***19956***
10. Coordinated Hydro Load (1929) 17/	**10969**	**11104**	**11081**	**9920**	**11458**	**13316**	**12878**	**11721**	**10501**	**9786**	**11502**	**13287**	**13867**	**12531**	***11855***	***11936***
a) Coord. Hydro Load Shape (29) 18/	92.5%	93.7%	93.5%	83.7%	96.6%	112.3%	108.6%	98.9%	88.6%	82.5%	97.0%	112.1%	117.0%	105.7%	100.0%	

Notes:
1/ Step I Loads and Resources for the Step I System as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements.
2/ The Step I critical period is the 42.5 months beginning 16 August 1928 and ending 29 February 1932.
3/ BPA 2006 White Book total regional firm load estimate on April 12, 2006, which includes estimated Coulee pumping and Idaho loads served by Utah Power and Light.
4/ Annex B requires exclusion of Idaho load (and corresponding import) from area served by Utah Power Light in 1964.
5/ Coulee pumping loads and flows in the WB06 were the same as the Feb. 1, 2006, PNCA data submittal.
6/ White Book exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and an estimate of the Canadian Entitlement.
7/ Assumes 510 MW Energy Entitlement with 125 MW used in PNWA and remainder exported to Canada.
8/ Added Seasonal Exchange which balances annually. See lines 2(d) and 3(d).
9/ Added thermal export to balance difference between thermal import and equivalent thermal installation based on generic annual shape.
10/ White Book Imports include coordinated thermal installations, seasonal & capacity exchanges, flow-through-transfers, and Skagit Treaty power.
11/ Imports supported by coordinated thermal installations are excluded, to be replaced by a portion of the Generic Thermal Installations. Line 2e balances annual shape difference.
12/ Wind resources based on Apr. 2006 BPA forecast of 2012 regional wind resources installed capacity times average Jan.2002 thru Feb.2005 BPA control area actual wind generation plant factors.
13/ Line 1(d)+ line 2(i) + line 3(f) + line 4(f), based on 1929 hydro independent capability
14/ Thermal installations are CGS, plus a generic thermal installation, that together with Step I Hydro resources, is sized to meet the Step 1 System load.
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 2.67% 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
2011-12 ASSURED OPERATING PLAN
DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES 1/
(MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. Pacific Northwest Area (PNWA) Firm Load														
a) White Book Regional Firm Load	28445	28438	26554	28167	30892	33543	34666	33139	30187	28130	28142	27529	28022	29060
b) Exclude 99% of UPL's Idaho load	-567	-567	-498	-446	-437	-445	-428	-441	-446	-431	-431	-496	-604	-664
c) Remove Federal Peak Diversity 1/	-904	-905	-891	-934	-839	-618	-650	-634	-831	-780	-783	-904	-904	-924
d) Updates to Coulee pumping forec.	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) ….Total PNWA Firm Loads	**26973**	**26965**	**25165**	**26787**	**29616**	**32480**	**33588**	**32064**	**28909**	**26920**	**26928**	**26130**	**26514**	**27472**
f) Monthly Load Factors in Percent	78.31	78.32	79.16	75.17	74.55	74.45	73.56	73.01	74.89	77.04	76.97	77.55	78.20	78.59
2. Flows-Out of firm power from PNWA														
a) WB06 Exports	1996	1996	1991	1820	1695	1696	1694	1695	1695	1723	1723	1690	1897	1898
b) Remove WB06 Canadian Entitle.	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350
c) Add estimated Can.Entitle. exported	1019	1019	1019	1019	1019	1019	1019	1019	1019	1019	1019	1019	1019	1019
d) Added Seasonal Exch. Export	0	0	1231	0	0	0	0	0	0	0	313	938	3165	1198
e) Thermal Insl.used outside region 2/	284	318	291	215	114	0	50	94	187	177	162	126	179	246
f) …Subtotal for Table 2	1949	1983	3182	1704	1478	1365	1413	1457	1551	1569	1867	2423	4909	3011
g) Remove Plant Sales	-191	-191	-191	-191	-191	-191	-191	-191	-191	-191	-191	-45	-191	-191
h) Remove Flow-through-transfer	-75	-1025	-1036	-1049	-1061	-842	-1069	-1064	-1057	-1050	-1050	-520	-1032	-1023
i) …Total	**1683**	**767**	**1955**	**464**	**226**	**332**	**154**	**203**	**303**	**328**	**626**	**1859**	**3686**	**1797**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations														
a) WB06 Imports	-945	-911	-888	-877	-975	-1140	-1104	-1106	-1011	-895	-910	-901	-1049	-1073
b) Exclude UP&L imports for 1(b)	567	567	498	446	437	445	428	441	446	431	431	496	604	664
c) Remove Thermal Install Imports	175	141	169	239	336	450	400	356	263	230	245	185	247	210
d) Add Seasonal Exch. Imports	-196	-66	0	-93	-261	-508	-1620	-1696	-1650	-1452	0	0	0	0
e) Remove Flow-Through-Transfer	75	75	75	45	45	45	45	45	45	75	75	75	75	75
f) …Total	**-324**	**-193**	**-147**	**-240**	**-418**	**-709**	**-1851**	**-1960**	**-1907**	**-1611**	**-159**	**-146**	**-122**	**-124**
4. PNWA Non-Step I Hydro and Non-thermal Resources														
a) Hydro Independents (1937 water)	-1785	-1764	-1756	-1675	-1595	-1586	-1546	-1654	-1758	-1841	-1847	-1916	-1933	-1840
b) Non-Step I Coordinated Hydro(1937)	-2508	-2430	-2529	-2464	-2365	-2292	-1501	-1330	-2024	-2039	-2088	-2172	-2315	-2498
c) Miscellaneous resources (Wind)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d) Misc. Resources (NUG small Hydro)	-338	-336	-268	-186	-138	-127	-121	-131	-165	-276	-276	-397	-411	-405
e) Misc. Resources (Renewables)	-23	-23	-23	-23	-23	-23	-23	-23	-23	-23	-23	-23	-23	-23
f) …Total (1937)	**-4654**	**-4553**	**-4575**	**-4348**	**-4121**	**-4028**	**-3190**	**-3138**	**-3970**	**-4179**	**-4235**	**-4508**	**-4682**	**-4766**
5. Step I System Load (1937) 3/	**23678**	**22985**	**22398**	**22663**	**25303**	**28075**	**28701**	**27168**	**23334**	**21458**	**23161**	**23334**	**25395**	**24378**
6. Coordinated Thermal Installations														
a) Columbia Generating Station(cgs)	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
b) Generic Thermal Installations	10506	10506	10512	10382	10292	10303	10305	10299	10287	9311	9311	7107	9744	10417
c) ...Total	**11656**	**11656**	**11662**	**11532**	**11442**	**11453**	**11455**	**11449**	**11437**	**10461**	**10461**	**8257**	**10894**	**11567**
7. Step I Hydro Resc.needed(1937)4/	**20728**	**19332**	**18400**	**18264**	**21141**	**23429**	**23781**	**22767**	**18741**	**17728**	**19177**	**21394**	**21177**	**20770**
8. Step I Resource Adjustments														
a) Hydro Maintenance 5/	-4595	-4032	-3787	-3208	-2935	-2037	-1561	-2286	-2626	-2751	-2483	-2360	-2202	-3720
b) Transm. System Losses 6/	-907	-881	-863	-864	-954	-1051	-1129	-1082	-976	-902	-877	-891	-962	-933
c) Reserves (approx 11%) 7/	-3204	-3089	-3015	-3060	-3392	-3718	-3844	-3679	-3242	-3077	-3117	-3066	-3511	-3307
9. Required Step I Resources(1937)	**23678**	**22985**	**22398**	**22663**	**25303**	**28075**	**28701**	**27168**	**23334**	**21458**	**23161**	**23334**	**25395**	**24378**
10. Coordinated Hydro Load(1937) 8/	23236	21762	20929	20728	23506	25721	25282	24097	20765	19767	21265	23566	23492	23268

Notes:
1/ Federal peak diversity is a reduction in peak load to reflect the fact that not all peak loads occur simultaneously across the region.
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 + 2i + 3f + 4f
4/ Step I hydro resources needed to meet the load = line 5 minus lines 6c, 8a, 8b, & 8c. Actual resource capability is higher.
5/ From WB06, 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 peak load, including absolute value of exports minus imports.
7/ Reserves are same percent of total load, including exports, as WB06 (approximately 11%).
8/ Coordinated hydro model load = Line 7 minus line 4b.

TABLE 2

2011-12 ASSURED OPERATING PLAN
DETERMINATION OF THERMAL DISPLACEMENT MARKET
(Energy in Average MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	June	July	Annual Average	CP Ave (42.5mon)
1. STEP I THERMAL INSTALLATIONS																
a) From Table 1A, line 6(c)	9886	9911	9978	9823	9857	9884	9852	9830	8983	8962	8962	6889	9201	9803	9410.3	9480.3
2. DISPLACEABLE THERMAL RESOURCES																
a) Min.Gen. as % of Thermal	221	222	224	220	221	221	220	220	199	198	198	147	204	219	209.4	211.2
b) Net Displaceable Thermal Res.	**9665**	**9689**	**9755**	**9603**	**9637**	**9663**	**9632**	**9610**	**8784**	**8764**	**8764**	**6742**	**8997**	**9584**	**9200.8**	**9269.1**
3. SYSTEM SALES																
a) Flows-Out(Table 1A,Line 2(f))	1069	1099	2304	879	778	687	726	769	795	831	1117	1656	4121	2171	1408.6	1351.7
b) Exclude Firm Seasonal Exch.	-29	-29	-40	-14	0	0	0	0	0	0	0	-28	-58	-30	-16.6	-15.7
c) Exclude Added Seas. Exch.	0	0	-1231	0	0	0	0	0	0	0	-313	-938	-3165	-1198	-554.0	-499.0
d) Exclude Plant Sales	-173	-173	-173	-173	-173	-173	-173	-173	-173	-173	-165	-36	-173	-173	-161.1	-162.9
e) Exclude Flow-Through Xfers	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60.0	-58.8
f) Exclude Can. Entitl. Export	-385	-385	-385	-385	-385	-385	-385	-385	-385	-385	-385	-385	-385	-385	-385.0	-385.0
g) ...Total System Sales	**407**	**437**	**400**	**262**	**175**	**84**	**123**	**166**	**192**	**198**	**179**	**194**	**265**	**310**	**231.9**	**230.3**
h) Uniform Avg.Ann.Sys.Sales	232	232	232	232	232	232	232	232	232	232	232	232	232	232	231.9	231.9
4 THERMAL DISPLACEMENT M	**9433**	**9457**	**9523**	**9372**	**9405**	**9431**	**9400**	**9378**	**8552**	**8532**	**8532**	**6510**	**8765**	**9352**	**8968.9**	**9037.2**

Notes:

2a Minimum generation is 0.0249 times the annual average Step 1 thermal, without CGS; based on 2006 AOP data.

3a Flows-Out include firm seasonal exchange exports; thermal used outside the region, plant sales, flow-through-transfers, and Canadian Entitlement Exports.

3b Firm Seasonal Exchange Exports included in Line 3(a) are supported by Firm Seasonal Exchange Imports.

3c Added Seasonal Exchange Exports (Line 2(d), Table 1A) are supported by Added Seasonal Exchange imports.

3d Plant sales include Longview Fibre and approximately 25 percent of Boardman; line 2(g), Table 1A. They are excluded here because they are also excluded on Table 1 calc of thermal.

3e Flow through transfers are Flows-in that support the same Flows-Out in the same period. This is a wheel to outside the region and back in to meet a regional (So. OR) load.

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

3g System Sales are total exports excluding exchanges, plant sales, flow-thru-xfers, and the Canadian Entitlement. The sum of Lines 3(a) through 3(f).

3h 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(h).

TABLE 3
2011-12 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR
STEP II AND STEP III STUDIES

LOAD OF THE PACIFIC NORTHWEST AREA						STEP II STUDY		STEP III STUDY		
Period	PNW Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Energy Capability of Thermal Installations 2/ aMW	Total Load 3/ aMW	Hydro Load 4/ aMW	Total Load 3/ aMW	Hydro Load 4/ aMW	Period
Aug. 1-15	21124	97.30	26973	78.31	9886	17822.0	7936.1	15216.8	5330.9	Aug. 1-15
Aug. 16-31	21119	97.27	26965	78.32	9911	17817.6	7906.5	15213.1	5301.9	Aug. 16-31
September	19921	91.76	25165	79.16	9978	16807.3	6829.1	14350.4	4372.2	September
October	20137	92.75	26787	75.17	9823	16989.4	7166.3	14505.9	4682.8	October
November	22080	101.70	29616	74.55	9857	18628.5	8771.3	15905.4	6048.2	November
December	24181	111.38	32480	74.45	9884	20400.9	10516.7	17418.8	7534.5	December
January	24708	113.81	33588	73.56	9852	20845.8	10993.8	17798.6	7946.6	January
February	23410	107.82	32064	73.01	9830	19750.3	9920.1	16863.2	7033.0	February
March	21651	99.72	28909	74.89	8983	18266.3	9283.4	15596.2	6613.2	March
April 1-15	20739	95.52	26920	77.04	8962	17497.0	8535.0	14939.3	5977.3	April 1-15
April 16-30	20726	95.46	26928	76.97	8962	17486.3	8524.3	14930.2	5968.2	April 16-30
May	20263	93.33	26130	77.55	6889	17095.8	10207.1	14596.8	7708.0	May
June	20735	95.50	26514	78.20	9201	17493.6	8292.7	14936.4	5735.5	June
July	21591	99.45	27472	78.59	9803	18216.3	8413.2	15553.5	5750.4	July
Annual Avg. 7/	21710.9	100.00		76.21	9410.3	18317.1	8906.8	15639.5	6229.3	Annual Avg
SI CP Avg (42.5)	21798.2			**76.07**	9480.3					<==Au31-Feb
S2 CP Avg (20)	21866.3				9503.5	18448.1	8944.6			<==Sep-Ap30
S3 CP Avg.(5.5)	22986.1				9612.6			16558.1	6945.5	<==Nov-Ap15
						Input 5/=	**8944.62**	Input 6/=	**6945.48**	
August 1-31	21121.4	97.3	26973.4	78.32	9898.9	17819.7	7920.8	15214.9	5316.0	Aug. 1-31
April 1-30	20732.6	95.5	26928.1	77.00	8962.1	17491.7	8529.6	14934.8	5972.7	Apr. 1-30

Notes:

1/ The PNW Area load does not include the exports, but does include pumping. The computation of the Step II/III load shape uses this load.

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

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 2010-11 operating year. The critical period (CP) averages are for the historic water years.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2011-12 ASSURED OPERATING PLAN

	BASIC DATA		STEP I			STEP II				STEP III			
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE kaf	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
1. HYDRO RESOURCES													
a) CANADIAN STORAGE													
Mica			7000			7000							
Arrow			7100			7100							
Duncan			1400			1400							
Subtotal			15500			15500							
b) BASE SYSTEM													
Hungry Horse	4	428	3072	289	102	3008	193	115	103	3008	332	235	104
Kerr	3	180	1219	176	124	1219	175	112	130	1219	174	153	123
Thompson Falls	6	85	0	85	56	0	85	53	59	0	85	66	57
Noxon Rapids	5	554	231	523	147	0	528	128	195	0	528	173	195
Cabinet Gorge	4	239	0	238	98	0	238	86	120	0	238	113	118
Albeni Falls	3	50	1155	21	24	1155	18	22	21	1155	11	16	19
Box Canyon	4	68	0	71	46	0	70	44	48	0	69	57	47
Grand Coulee	24+3SS	6684	5185	6360	2057	5072	6364	1839	2396	5072	5617	1215	2298
Chief Joseph	27	2535	0	2535	1066	0	2535	968	1307	0	2535	700	1233
Wells	10	780	0	840	420	0	840	388	490	0	840	286	441
Chelan	2	54	677	51	38	676	51	38	44	676	51	45	43
Rocky Reach	11	1267	0	1267	573	0	1267	529	693	0	1267	384	642
Rock Island	18	547	0	547	263	0	547	246	314	0	547	181	289
Wanapum	10	825	0	825	501	0	825	464	588	0	825	328	520
Priest Rapids	10	770	0	770	488	0	770	455	562	0	770	329	496
Brownlee	5	675	975	675	243	974	675	301	320	974	675	264	320
Oxbow	4	220	0	220	101	0	220	126	130	0	220	116	130
Ice Harbor	6	693	0	693	215	0	693	231	303	0	693	163	303
McNary	14	1127	0	1127	626	0	1127	602	771	0	1127	442	716
John Day	16	2484	535	2484	942	0	2484	917	1255	0	2484	683	1215
The Dalles	22+2F	2074	0	2074	750	0	2074	731	994	0	2074	563	971
Bonneville	18+2F	1088	0	1047	566	0	1047	550	683	0	1047	432	640
Kootenay Lake	0	0	673	0	0	673	0	0	0	673	0	0	0
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	223	0	0	0
Total Base System 1/		23427	29445	22918	9445	28500	22825	8945	11526	13000	22207	6945	10921
c) ADDITIONAL STEP I PROJECTS													
Libby	5	600	4980	540	196								
Boundary	6	1005	0	855	367								
Spokane River Plants 2/	24	171	104	158	94								
Hells Canyon	3	450	0	379	199			NOT APPLICABLE TO STEP II & III					
Dworshak	3	450	2015	445	157								
Lower Granite	6	932	0	930	171								
Little Goose	6	932	0	928	179								
Lower Monumental	6	932	0	923	171								
Pelton, Rereg., & RB	7	423	274	419	136								
Total added Step I		5895	7373	5576	1671								
2. THERMAL INSTALLATIONS 3/				11455	9480		11455	9504	9410		11455	9613	9410
3. TRANSMISSION LOSSES, HYDRO MAINTENANCE & PEAK RESERVES 4/				-6535	-640		-4295	0	0		-3807	0	0
4. TOTAL RESOURCES 5/				33414	19956		29985	18448	20936		29855	16558	20331
5. STEP I, II, & III SYSTEM LOADS 6/				28701	19956		28338	18448	18317		24195	16558	15640
6. SURPLUS (4 - 5)				4713	0		1647	0	2619		5659	0	4692
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			12-41			12-42				12-13		

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 and II includes Canadian storage.

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

3/ From Tables 1 and 3.

4/ Step I peak transmission losses, hydro maintenance and reserves are from Table 1b, lines 8a+b+c. Energy transmission losses and maintenance from Table 1a, lines 8a+8b. Steps II & III Peak Reserves & Maintenance are based onsame percent as WB06, i.e. approximately 11% of load for reserves and 5.1% of hydro capability for maintenance. Hydro maintenance energy losses are not included in Steps II & III. Energy reserves for thermal installations are included in the thermal installation energy forecast.

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

6/ 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 from Table 3.

TABLE 4M
(Metric Units)
SUMMARY OF POWER REGULATIONS
FROM 2011-12 ASSURED OPERATING PLAN

	BASIC DATA		STEP I			STEP II				STEP III 4/			
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE hm^3	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
1. HYDRO RESOURCES													
a) CANADIAN STORAGE													
Mica			8635			8635							
Arrow			8758			8758							
Duncan			1727			1727							
Subtotal			19119			19119							
b) BASE SYSTEM													
Hungry Horse	4	428	3789	289	102	3710	193	115	103	3710	332	235	104
Kerr	3	180	1504	176	124	1504	175	112	130	1504	174	153	123
Thompson Falls	6	85	0	85	56	0	85	53	59	0	85	66	57
Noxon Rapids	5	554	285	523	147	0	528	128	195	0	528	173	195
Cabinet Gorge	4	239	0	238	98	0	238	86	120	0	238	113	118
Albeni Falls	3	50	1425	21	24	1425	18	22	21	1425	11	16	19
Box Canyon	4	68	0	71	46	0	70	44	48	0	69	57	47
Grand Coulee	24+3SS	6684	6396	6360	2057	6256	6364	1839	2396	6256	5617	1215	2298
Chief Joseph	27	2535	0	2535	1066	0	2535	968	1307	0	2535	700	1233
Wells	10	780	0	840	420	0	840	388	490	0	840	286	441
Chelan	2	54	835	51	38	834	51	38	44	834	51	45	43
Rocky Reach	11	1267	0	1267	573	0	1267	529	693	0	1267	384	642
Rock Island	18	547	0	547	263	0	547	246	314	0	547	181	289
Wanapum	10	825	0	825	501	0	825	464	588	0	825	328	520
Priest Rapids	10	770	0	770	488	0	770	455	562	0	770	329	496
Brownlee	5	675	1203	675	243	1201	675	301	320	1201	675	264	320
Oxbow	4	220	0	220	101	0	220	126	130	0	220	116	130
Ice Harbor	6	693	0	693	215	0	693	231	303	0	693	163	303
McNary	14	1127	0	1127	626	0	1127	602	771	0	1127	442	716
John Day	16	2484	660	2484	942	0	2484	917	1255	0	2484	683	1215
The Dalles	22+2F	2074	0	2074	750	0	2074	731	994	0	2074	563	971
Bonneville	18+2F	1088	0	1047	566	0	1047	550	683	0	1047	432	640
Kootenay Lake	0	0	830	0	0	830	0	0	0	830	0	0	0
Coeur d'Alene Lake	0	0	275	0	0	275	0	0	0	275	0	0	0
Total Base System 1/		23427	36320	22918	9445	35155	22825	8945	11526	16036	22207	6945	10921
c) ADDITIONAL STEP I PROJECTS													
Libby	5	600	6143	540	196								
Boundary	6	1005	0	855	367								
Spokane River Plants 2/	24	171	128	158	94								
Hells Canyon	3	450	0	379	199								
Dworshak	3	450	2486	445	157								
Lower Granite	6	932	0	930	171								
Little Goose	6	932	0	928	179								
Lower Monumental	6	932	0	923	171								
Pelton, Rereg., & RB	7	423	338	419	136								
Total added Step I		5895	9095	5576	1671								
								NOT APPLICABLE TO STEP II & III					
2. THERMAL INSTALLATIONS 3/				11455	9480		11455	9504	9410		11455	9613	9410
3. TRANSMISSION LOSSES, HYDRO MAINTENANCE & PEAK RESERVES 4/				-6535	-640		-4295	0	0		-3807	0	0
4. TOTAL RESOURCES 5/				33414	19956		29985	18448	20936		29855	16558	20331
5. STEP I, II, & III SYSTEM LOADS 6/				28701	19956		28338	18448	18317		24195	16558	15640
6. SURPLUS (4 - 5)				4713	0		1647	0	2619		5659	0	4692
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		12-41			12-42				12-13			

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 and II includes Canadian storage.
2/ Spokane River Plants include: Little Falls, Long Lake, Nine Mile, Monroe, U Falls, and Post Falls.
3/ From Tables 1 and 3.
4/ Step I peak transmission losses, hydro maintenance and reserves are from Table 1b, lines 8a+b+c. Energy transmission losses and maintenance from Table 1a, lines 8a+8b. Steps II & III Peak Reserves & Maintenance are based onsame percent as WB06, i.e. approximately 11% of load for reserves and 5.1% of hydro capability for maintenance. Hydro maintenance energy losses are not included in Steps II & III. Energy reserves for thermal installations are included in the thermal installation energy forecast.
5/ Total Resources is the sum of lines 1b+1c+2+3. For Step I, this does not include non-Step I coordinated hydro or hydro-independents.
6/ 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 from Table 3.

TABLE 5

COMPUTATION OF CANADIAN ENTITLEMENT FOR 2011-12 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 12-42)
B. Optimum Power Generation in the U.S. Only (From 12-12)
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km^3) Reduction in Total Canadian Treaty Storage (From 12-22). For information only, not needed for this DDPB (see section 3).

Determination of Dependable Capacity Credited to Canadian Storage (MW)

	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	8944.6	8944.6	8909.3
Step III - Critical Period Average Generation 2/	6945.5	6945.5	6945.5
Gain Due to Canadian Storage	1999.1	1999.1	1963.8
Average Critical Period Load Factor in percent 3/	76.07	76.07	76.07
Dependable Capacity Gain 4/	2628.0	2628.0	2581.6
Canadian Share of Dependable Capacity 5/	1314.0	1314.0	1290.8

Determination of Increase in Average Annual Usable Hydro Energy (aMW)

Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Firm Energy 6/	8904.7	8904.7	8869.7
Thermal Displacement Energy 7/	2448.7	2443.5	2457.4
Remaining Usable Energy 8/	69.1	70.3	73.6
System Average Annual Usable Energy	11422.5	11418.5	11400.7
Step III (without Canadian Storage) 2/			
Firm Energy 6/	6227.6	6227.6	6227.6
Thermal Displacement Energy 7/	3776.2	3776.2	3776.2
Remaining Usable Energy 8/	366.8	366.8	366.8
System Average Annual Usable Energy	10370.6	10370.6	10370.6
Average Annual Usable Energy Gain 9/	1051.9	1047.9	1030.1
Canadian Share of Average Annual Energy Gain 5/	525.9	523.9	515.0

1/ Step II values were obtained from the 12-42, 12-12, and 12-22 studies, respectively.
2/ Step III values were obtained from the 12-13 study and Table 3.
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 of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load served, which includes 7 leap years (29 days in Feb.).
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
(English & Metric Units)
COMPARISON OF RECENT DDPB STUDIES

	2007-08	2008-09	2009-10	2010-11	2011-12
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	24111.7	24495.5	22268.2	22033.0	21710.9
Annual/January Load (%)	87.4	87.3	87.5	88.1	87.9
Critical Period (CP) Load Factor (%)	75.8	75.7	73.9	75.9	76.1
Annual Firm Exports 1/	718.7	704.7	639.6	636.7	687.9
Annual Firm Surplus (MW) 2/	798.2	747.3	762.4	578.5	554.0
THERMAL INSTALLATIONS (MW) 3/					
January Peak Capability	11856	12417	9756	11762	11455
CP Energy	10819	11228	8891	9418	9480
CP Minimum Generation	237	245	196	212	211
Average Annual System Export Sales	255	259	144	333	232
Average Annual Displaceable Market	10270	10643	8504	8779	8969
HYDRO CAPACITY (MW)					
Total Installed	29689	29689	29689	29689	29322
Base System	23742	23742	23742	23742	23427
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 (cfs) 4/					
Step I 30-yr. Average Streamflow	176702	176702	175663	175395	175361
Step I CP Average	114401	114401	115061	114765	114734
Step II CP Average	101525	101525	101961	101628	101578
Step III CP Average	57184	57184	56558	56079	56027
BASE STREAMFLOWS AT THE DALLES (m^3/s) 4/					
Step I 30-yr. Average Streamflow	5003.64	5003.64	4974.22	4966.63	4965.67
Step I CP Average	3239.47	3239.47	3258.17	3249.79	3248.92
Step II CP Average	2874.87	2874.87	2887.22	2877.79	2876.38
Step III CP Average	1619.26	1619.27	1601.55	1587.99	1586.52
CAPACITY BENEFITS (MW)					
Step II CP Generation	9015.2	9018.7	9018.1	8998.2	8944.6
Step III CP Generation	7134.3	7132.2	7020.8	7000.1	6945.5
Step II Gain over Step III	1880.9	1886.5	1997.3	1998.1	1999.1
CANADIAN ENTITLEMENT	1240.9	1245.2	1352.3	1316.4	1314.0
Change due to Mica Reoperation	0.0	0.0	0.0	0.0	0.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm	8870.6	8921.2	8907.7	8981.9	8904.7
Step II Thermal Displacement	2586.5	2558.9	2444.1	2414.7	2448.7
Step II Remaining Usable Secondary	34.6	25.4	87.6	67.2	69.1
Step II System Average Annual Usable	11491.7	11505.5	11439.4	11463.8	11422.5
Step III Annual Firm	6150.8	6243.5	6174.1	6324.3	6227.6
Step III Thermal Displacement	4094.4	4084.5	3707.8	3699.3	3776.2
Step III Remaining Usable Secondary	280.8	247.7	423.2	368.7	366.8
Step III System Average Annual Average	10526.0	10575.7	10305.1	10392.3	10370.6
CANADIAN ENTITLEMENT	482.8	464.9	567.1	535.7	525.9
Change due to Mica Reoperation	1.7	1.9	3.9	2.0	2.0
STEP II PEAK CAPABILITY (MW)	32501	33008	30530	30601	29985
STEP II PEAK LOAD (MW)	30884	31564	28996	28258	28338
STEP III PEAK CAPABILITY (MW)	32381	32882	30371	30571	29855
STEP III PEAK LOAD (MW)	25063	25758	23142	24155	24195

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 does include plant sales.

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

AOP Study	Amount Shaped (MW)
2007-08	894 Aug 15, 902 Aug 31, 1293 Sep, 449 Apr 30, 2544 May, 2711 June, and 1890 July.
2008-09	1122 Aug 15, 1131 Aug 31, 1531 Sep, 524 Apr 30, 2136 May, 1807 June, and 2052 July.
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	313 April 30, 938 May, 3165 June, 1198 July, & 1231 Sept.

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 1990 level modified flows were used for the 2007-08 and 2008-09 DDPBs with adjustments for the Grand Coulee pumping and return flows. 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 and 2011-12 DDPBs include updated adjustments for the Grand Coulee pumping but not for return flows. Base Streamflows at The Dalles for 2011 have been amended in this 2012 document.

CHART 1

2011-12 DDPB STUDIES

DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)