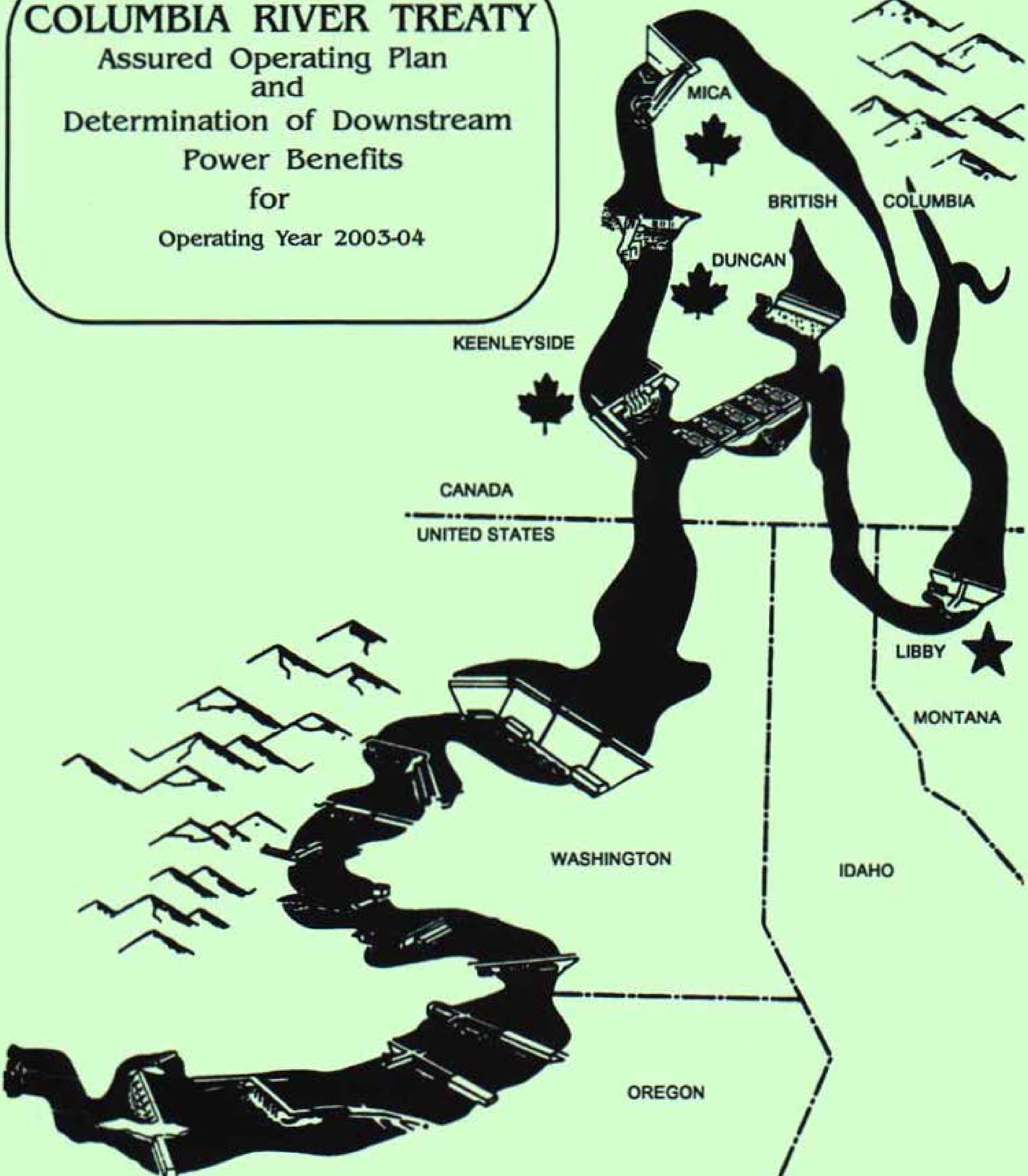
COLUMBIA RIVER TREATY

Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2003-04



Columbia River Treaty Operating Committee

January 2000

COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR THE 2003-04 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 on the resulting downstream power benefits six years in advance.

The Entities agree that the attached reports entitled "Columbia River Treaty Assured Operating Plan for Operating Year 2003-04" and "Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2003-04," both dated January 2000, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the Operating Year 2003-04.

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

Executed for the Canadian Entity this 16th day of February 2000.

By Brian Smith

Brian R.D. Smith, Chair

Executed for the United States Entity this 16th day of February 2000.

By Judi Johansen

Judith A. Johansen, Chairman

By Carl A. Strock

Brigadier General Carl A. Strock, Member

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 2003-04

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HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN FOR OPERATING YEAR 2003-04

January 2000

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) 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 plan provides the Entities with information for planning the power systems that are dependent on or coordinated with the operation of the Canadian storage projects.

This AOP was prepared in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans[1] (POP) and in accordance with the following 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/DDPB's, and Operating Procedures for the 2001-02 and Future AOP's," signed 29 August 1996 (29 August 1996 Entity Agreement);
- Principles[2] and on Changes to Procedures[3] for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, signed 28 July and 12 August 1988, respectively.

POP is based on criteria contained in Annex A and Annex B of the Columbia River Treaty,[4] the Protocol,[5] the Terms of Sale,[6] and the Columbia River Treaty Flood Control Operating Plan.[7]

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

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

(b) Operating Rules, that specifically designate criteria for operation of the Canadian storage in accordance with the principles contained in the above references.

(c) The supporting data and model used to simulate the 30-year operation for the Step I Joint Optimum hydroregulation study.[8]

This AOP includes both English and metric units.[9] For operational purposes, the English units should be used as having a degree of accuracy consistent with previous years' studies. Calculations based on 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 U.S. 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. System Regulation Studies

The Columbia River Treaty Operating Committee conducted Step I system regulation studies in accordance with Annex A, paragraph 7, of the Treaty, which requires Canadian storage operation for joint optimum power generation in both Canada and the United States. Downstream power benefits were computed with the Canadian 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 2003-04 estimated loads and resources in the United States Pacific Northwest System and hydro resources in the Columbia River Basin in British Columbia. In accordance with the Protocol VIII, the 2003-04 AOP is based on a 30-year streamflow period and the Entities have agreed to use an operating year of 1 August to 31 July. Historical flows for the period August 1928 through July 1958, modified by estimated irrigation depletions for the 1990 level and including the latest Grand Coulee pumping, were used.[10] The 1990 level is considered the best estimate of irrigation depletions for the 2003-04 operating year.

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

In the studies, individual project flood control criteria were followed. Flood Control and Variable Refill Curves are based on historical inflow volumes. Although only 15.5 million acre-feet (Maf) (19.12 cubic kilometers (km^3)) of usable storage is committed for power operation purposes under the Treaty, the Columbia River Treaty Flood Control Operating Plan provides for the full draft of the total 20.5 Maf (25.29 km^3) of usable storage for on-call flood control purposes.

3. Development of the Assured Operating Plan

This AOP was developed in accordance with Annex A, paragraph 7 of the Treaty which was designed to produce optimum power generation at-site in Canada and downstream in Canada and the United States. The Mica operating criteria specified in Table 1, and changes to the rule curves that are required to balance Canadian storage reoperation, which were used to increase optimum power generation in Canada and the U.S., were evaluated in accordance with subsection 13c of POP using the two limits described below.

(a) Determination of Optimum Generation in Canada and the United States

To determine whether optimum power generation in both Canada and the United States was achieved in the system regulation studies, the firm energy capability, dependable peaking capability, and average annual usable secondary energy were computed for both the Canadian and United States systems. The Canadian storage operation was designed to achieve a weighted sum of these three quantities that was greater than the weighted sum achieved under an operation of Canadian storage for optimum power generation in the United States of America alone.

In order to measure optimum power generation for the 2003-04 AOP, the Columbia River Treaty Operating Committee agreed that the three quantities would be assigned the following relative values:

Quantity	Relative Value
Firm energy capability (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 to the combined Canadian and United States systems in the study designed to achieve optimum power generation in Canada and the United States. The Entities agree that this result is in accordance with subsection 13c of the POP. The results of these calculations are shown in Table 2.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Separate Step II system regulation studies were developed reflecting (i) storage operation for optimum generation in both Canada and the United States, and (ii) storage operation for optimum generation in the United States alone. Using these storage operations for optimum generation in both Canada and the United States, there is a 1.1 aMW decrease in the Canadian Entitlement for average annual usable energy and 0.9 MW decrease in the dependable capacity compared to an operation for optimum generation in the United States alone.

The Entities have determined in Section 3 of the 2003-04 DDPB that these changes are within the maximum permitted reduction in downstream power benefits specified by the Treaty.

4. Rule Curves

The operation of Canadian storage during the 2003-04 Operating Year shall be guided by the ORC and CRC's for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, and operating rules for specific projects. The ORC's and CRC's are first determined for the individual Canadian projects and then summed to yield the Composite ORC for the whole of Canadian storage, in accordance with paragraph VII (2) of the Protocol. The ORC is derived from the various curves described below.

(a) Critical Rule Curve

The CRC is defined by the end-of-period storage content of Canadian storage during the critical period. It is also used to determine proportional draft below the ORC as defined in subsection 5(b). The CRC's are first adjusted for crossovers at each project before being summed for the Composite CRC. A tabulation of the CRC's for Duncan, Arrow, Mica, and the Composite CRC for the whole of Canadian storage is included as 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 sections. Tabulations of the ARC's and VRC's and the power discharge requirements (PDR's) used in determining the ARC's and VRC's for Mica, Arrow, and Duncan are provided in Tables 4-6, respectively.

(1) Assured Refill Curve (ARC)

The ARC indicates the August through June end-of-period storage contents required to assure refill of Canadian storage by July 31st. The ARC is based on the 1930-31 water year inflows, upstream storage requirements, and PDR's determined in accordance with the POP. The 1931 water year is the system's second lowest historical January through July volume of inflow, at The Dalles, Oregon, during the 30-year streamflow record.

(2) Variable Refill Curve (VRC)

The VRC indicates the January through June end-of-period storage contents required to refill Canadian storage by July 31st. The VRC is based on the 95% confidence forecasted inflow volume, upstream storage requirements, and PDR's determined in accordance with the POP. In the system regulation studies, historical volume inflows, adjusted for the 95% confidence forecast error, were used instead of forecasted inflows. The PDR's are a function of the unregulated January through July runoff volume at The Dalles, Oregon. In those years when the January through July runoff volume at The Dalles is between 80 Maf (98.68 km^3) and 110 Maf (135.69 km^3), the PDR's 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 80 Maf (98.68 km^3) or greater than 110 Maf (135.69 km^3), the discharge used was that specified for 80 and 110 Maf (98.68 km^3 and 135.69 km^3) respectively.

VRC's for Mica, Arrow and Duncan for the 30 years of historical record in Tables 4-6 illustrate the probable range of these curves based on historical conditions. In actual operation in 2003-04, the PDR's will be based on the forecast of unregulated runoff at The Dalles.

(c) Limiting Rule Curve (LRC) or Energy Content Curve Lower Limit (ECCLL)

The LRC's indicate 31 January through 15 April end-of-period storage contents. These contents must be maintained to protect the ability of the system to meet firm load during the period January through 30 April 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 VRC to be no lower than the LRC's. The LRC is developed for 1936-37 water conditions. The LRC's for Mica, Arrow and Duncan are shown in Tables 4-6 respectively.

(d) Upper Rule Curve (Flood Control)

The URC's indicate the end-of-period storage content to which each individual Canadian storage project shall be evacuated for flood control. The URC's used in the studies were based upon Flood Control Storage Reservation Diagrams contained in the Columbia River Treaty Flood Control Operating Plan[11] and analysis of system flood control simulations.[12] URC's for Mica, Arrow and Duncan for the 30-year study period are shown on Tables 7-9 respectively. Tables 7 and 8 reflect an agreed transfer of flood control space in Mica and Arrow to maximum drafts of 2.08 and 5.1 Maf (2.57 and 6.29 km^3) respectively. In actual operation, the URC's will be computed as outlined in the Flood Control Operating Plan using the latest forecast of runoff available at that time.

(e) Operating Rule Curve

The ORC's 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 United States 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 or the ARC, whichever is higher. During the period 1 January through 31 July, the ORC is defined as the higher of the CRC and the ARC; unless the VRC is lower, then it defines the ORC. During the period 1 January through 15 April, the ORC will not be lower than the LRC. The ORC shall be less than or equal to the URC. The composite ORC for the whole of Canadian storage for 30 years of historical record are included in Table 10 to illustrate the probable future range of these curves based on historical conditions. The lower of the Energy Content Curves for United States reservoirs and the URC's are equivalent to ORC's.

5. Operating Rules

A 30-year System Regulation Study[13] was utilized to develop and test the operating rules and rule curves. It contains the agreed-upon ORC's and CRC's, 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 Appendixes A1 and A2.

The following rules, used in the 30-year System Regulation Study, will apply to the operation of Canadian storage in the 2003-04 Operating Year.

(a) Operation Above ORC

The whole of the Canadian storage will be drafted to its ORC as required to produce optimum generation in Canada and the United States in accordance with Annex A, paragraph 7, of the Treaty, subject to project physical characteristics, operating constraints, and the criteria for the Mica project listed in section 5(c).

(b) Operation Below ORC

The whole of Canadian 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 United States system. FELCC is determined by the applicable Critical Period Regulation study. Proportional draft between rule curves will be determined as described in the POP.

Mica Reservoir will, however, continue to be operated in accordance with section 5(c) below, so as to optimize generation at site and at Revelstoke as well as downstream in the United States. In the event the Mica operation results in more or less than the project's proportional share of draft from the whole of Canadian storage, compensating changes will be made from Arrow to the extent possible.

(c) Mica Project Operation

Mica project operation will be determined by Arrow's storage content at the end of the previous period as shown in Table 1. Mica outflows will be increased above the values shown in the table in the periods from October through June if required to avoid storage above the URC.

Under this AOP, Mica storage releases in excess of 7.0 Maf (8.63 km^3) 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 14.1 Maf (17.39 km^3), unless flood control criteria will not permit the additional Mica storage releases to be retained at Arrow. Should storage releases in excess of 14.1 Maf (17.39 km^3) be made, the target Mica operation will remain as specified in Table 1.

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta have been included in the 2003-04 AOP and have been operated as run-of-river projects. Generation at Arrow was modeled in the studies. Corra Linn and Kootenay Canal were included and operated in accordance with criteria that closely approximates International Joint Commission rules for Kootenay Lake.

6. Implementation

The Entities have agreed that each year a Detailed Operating Plan (DOP) will be prepared for the immediately succeeding operating year. Such DOP's 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 2003-04 DOP will reflect the latest available load, resource, and other pertinent data to the extent the Entities agree these 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 2003-04 DOP. Failing agreement on updating the data and/or criteria, the 2003-04 DOP for Canadian storage shall include the rule curves, Mica operating criteria, and other data and criteria provided in this AOP. Actual operation of Canadian storage during the 2003-04 Operating Year shall be guided by the DOP.

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 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 Flood Control Operating Plan. When refill of Canadian 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.[14]

7. Canadian Entitlement

By 1 April 2003 all of the Canadian Entitlement to downstream power benefits attributed to the operation of Duncan, Arrow, and Mica dams, will cease to be covered by the Terms of the Sale of the Canadian Entitlement in the United States of America authorized by an Exchange of Notes between Canada and the United States of America dated 16 September 1964.[15] This AOP has been prepared on the basis that all of the Canadian Entitlement to downstream power benefits belongs to Canada.

(a) Delivery of the Canadian Entitlement

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 at any point on the Canada-United States of America boundary near Oliver, the Entities completed an agreement on Aspects of the Canadian Entitlement Return for 1 April 1998 through 31 March 2003,[16] executed 28 July 1992. This agreement has now been replaced by the Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024, dated 29 March 1999.[17] This arrangement covers the full 1 August 2003 through 31 July 2004 period covered by this AOP.

(b) Capacity/Energy Entitlement Scheduling Guidelines

The Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024,[18] specifies transmission losses and scheduling guidelines for delivery of the Canadian Entitlement.

8. Summary of Changes from Previous Year

Data from the five most recent AOP's are summarized in Table 11. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Non-Hydro Resources

Loads for the 2003-04 AOP were based on the unpublished 1997 Whitebook medium case forecast developed by BPA on 31 December 1996 for the 1999 through 2008 operating years. This forecast was also used in the 2002-03 AOP. The Pacific Northwest Area (PNWA) firm energy load increased by 103 aMW compared to the 2002-03 AOP. Other load changes include:

- This is the first AOP where all of the Canadian Entitlement belongs to Canada during the entire operating year. It was assumed that one-half of the Canadian Entitlement was exported to B.C., and the remaining one-half was disposed in the U.S. This resulted in an increase of 35 aMW in the Canadian Entitlement exports (B.C. + S.W.) compared to the 2002-03 AOP study, which modeled one-half of the Entitlement exported to Canada, one-eighth exported to the Southwest, and three-eighths of the Entitlement used to meet load in the PNWA.

The estimated disposition of the Entitlement in the Step I system and the computed Canadian Entitlement are shown below:

During 1 August 2003 – 31July 2004

Entitlement	**Energy (aMW)**		**Capacity (MW)**	
	Estimated	Computed	Estimated	Computed
Export to BC	267.25	268.65	585.35	588.2
Retained in PNW	267.25	268.65	585.35	588.2
Total	534.5	537.3	1170.7	1176.4

Iterative studies to correct the load estimate were not performed because updating the Canadian Entitlement estimates would not significantly affect the results of the studies.

- New exports were BPA to Central Montana Power Sale, and BPA to Big Horn Power Sale.
- Contracts with Imperial were terminated.
- A seasonal exchange import of 950 MW each period was added in January through 15 April to balance the seasonal exchange export of 1095 MW added in May through July. This created an annual average surplus in the spring similar to that of the previous year's study. An additional 396 MW of firm surplus was shaped May through July. The average annual firm surplus increased by 51 aMW compared to the 2002-03 AOP study.

The total annual energy capability of the thermal installations decreased by 19 aMW due to the following changes:

- Large Thermal resources decreased by 22 aMW due to data updates for Colstrip 1– 4;
- Cogeneration increased by 19 aMW mostly due to increased generation at Encogen; and
- Thermal PURPA/NUGS decreased by 20 aMW because of decreased generation in NUGS from Puget and WWP;

Thermal displacement market increased by 208 aMW largely due to decreased system sales.

(b) Operating Procedures

Generation plant data tables for Arrow, Grand Coulee, McNary, Bonneville, and Chief Joseph were updated. Grand Coulee showed increased critical period generation, while McNary, Bonneville, and Chief Joseph had significant decreased critical period generation. Mica full storage content decreased by 262.8 ksfd (643.0 hm^3), or 0.521 Maf (0.64 km^3), to show B.C. Hydro Refill Storage on top of Treaty storage, as shown below;

Mica Storage & Elevation

AOP Study	Full Storage (Ksfd)	Full Storage Metric (hm^3)	Full Elev (ft)	Full Elev Metric (m)
2002-03	6087.9	14894.7	2475.00	754.38
2003-04	5825.1	14251.7	2470.07	742.88

Generation reductions of approximately 0.2% due to step-up transformer losses were included for all U.S. federal projects.

The established operating procedures for Base system projects were agreed to by the 29 August 1996 Entity Agreement. These requirements are essentially the nonpower requirements included in the 1979-80 and prior AOP/DDPB studies. Changes from the previous studies include:

Base System Projects

- Kerr modeling technique was included in all studies (Steps I, II, & III). This operation was consistent with the 1979-80 operation of Kerr and enabled Kerr to meet the Federal Energy Regulatory Commission (FERC) license flood control requirement in April 15 more often. (58.6 ksfd (143.37 hm^3) was added as a maximum storage limit in March for all years outside of the critical period.)
- Arrow generation was included with a maximum capability of 160.8 MW.

Non-base System Projects

- Added 30 cfs (0.85 m^3/s) of other spill in all periods at LaGrande;
- Little Goose spill cap changed from 25 kcfs (707.91 m^3/s) to 30 kcfs (849.50 m^3/s);
- Gorge minimum flow requirement was updated.

REFERENCES

1 "Columbia River Treaty Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans, Columbia River Treaty Operating Committee," dated December 1991.

2 "Columbia River Treaty Entity Agreement on Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 28 July 1988.

3 "Columbia River Treaty Entity Agreement on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 12 August 1988.

4 "Treaty between the United States of America and Canada relating to Cooperative Development of the Water Resources of the Columbia River Basin," dated 17 January 1961.

5 "Protocol - Annex to Exchange of Notes," dated 22 January 1964.

6 "Attachment Relating to Terms of Sale - Attachment to Exchange of Notes," dated 22 January 1964.

7 "Columbia River Treaty Flood Control Operating Plan," dated October 1972, as amended by the "Review of Flood Control, Columbia River Basin, Columbia River and Tributaries Study, CRT-63," dated June 1991.

8 "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 03-41," dated 19 February 1999.

9 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).

10 "Report on 1990 Level Modified Streamflows, 1928 to 1989, Columbia River and Coastal Basins, prepared for BPA," dated July 1993.

11 See footnote 8.

12 Summary of "End-of-Period Reservoir Storage Requirement from Columbia River Flood Regulation Studies," dated July 1996.

13 See footnote 9.

14 See footnote 8.

15 Exchange of notes "Regarding the Disposal of the Canadian Entitlement to Downstream Power Benefits," dated 16 September 1964.

16 "Columbia River Treaty Entity Agreement on Aspects of the Canadian Entitlement Return for 1 April 1998 through 31 March 2003," executed 28 July 1992.

17 "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.

18 See footnote 17.

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2003-04 ASSURED OPERATING PLAN

	End of Previous Period Arrow Storage Content	-------- Target Operation --------		Minimum	MinimumTreaty
		Period Average	End-of-Period	Outflow	Storage Content 2/
		Outflow	Treaty Content 1/		
Period	(ksfd)	(cfs)	(ksfd)	(cfs)	(ksfd)
August 1-15	2600 - FULL	-	3499.2	15000	0.0
	1650 - 2600	25000			
	0 - 1650	30000			
August 16-31	3400 - FULL	-	3529.2	15000	0.0
	1450 - 3400	25000			
	0 - 1450	31000			
September	3460 - FULL	-	3529.2	10000	0.0
	1870 - 3460	22000			
	870 - 1870	27000			
	0 - 870	31000			
October	3225 - FULL	-	3374.1	10000	0.0
	2530 - 3225	21000			
	1940 - 2530	23000			
	0 - 1940	32000			
November	3295 - FULL	20000		12000	0.0
	2655 - 3295	22000			
	1410 - 2655	24000			
	0 - 1410	32000			
December	3010 - FULL	23000		21000	204.1
	1895 - 3010	25000			
	1380 - 1895	27000			
	0 - 1380	32000			
January	2510 - FULL	25000		15000	91.3
	1380 - 2510	28000			
	1240 - 1380	26000			
	0 - 1240	28000			
February	1200 - FULL	21000		15000	0.0
	68 - 1200	23000			
	52 - 68	20000			
	0 - 52	24000			
March	1530 - FULL	19000		15000	0.0
	860 - 1530	25000			
	370 - 860	19000			
	0 - 370	26000			
April 1-15	1660 - FULL	-	204.1	13000	0.0
	970 - 1660	-	4.1		
	935 - 970	24000			
	0 - 935	-	134.1		
April 16-30	1240 - FULL	15000	-	15000	0.0
	900 - 1240	12000	-		
	200 - 900	-	0.0		
	0 - 200	14000			
May	780 - FULL	10000		8000	0.0
	245 - 780	8000			
	120 - 245	17000			
	0 - 120	14000			
June	1570 - FULL	10000		8000	0.0
	1050 - 1570	8000			
	320 - 1050	10000			
	0 - 320	21000			
July	1940 - FULL	-	3449.2	8000	0.0
	1820 - 1940	19000			
	1700 - 1820	12000			
	0 - 1700	27000			

1/ A maximum outflow of 34000 cfs will apply if the target end-of-period storage content @ Mica is less than 3529.2 ksfd in every month except April 16-30, May, and June. For these periods, the maximum outflow is 27000 cfs in April 16-30, 30000 cfs in May and 33000 cfs in June.

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 2
COMPARISON OF 2003-04 ASSURED OPERATING PLAN
STUDY RESULTS

Study 04-41 provides Optimum Generation in Canada and in the United States.
Study 04-11 provides Optimum Generation in the United States only.

	Study No. 04-41	Study No. 04-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	12011.0	12012.2	-1.2		
Canada 2/, 3/	2921.6	2878.5	43.1		
Total	14932.6	14890.7	41.9	3	125.7
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	30910.0	30894.0	16.0		
Canada 2/, 5/	5676.0	5668.0	8.0		
Total	36586.0	36562.0	24.0	1	24.0
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3174.3	3161.4	12.9		
Canada 2/, 7/	244.7	269.0	-24.3		
Total	3419.0	3430.4	-11.4	2	-22.8
			Net Change in Value =		126.9

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)
2003 - 04 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3526.0	3528.6	3358.8	2939.1	2402.9	1652.7	1556.3	1100.1	419.3	127.6	369.4	1969.0	3189.1
1929-30	3528.3	3502.5	3430.7	2981.7	2142.2	1775.1	1027.9	1020.3	548.2	0.0	0.0	327.3	1962.1	3169.7
1930-31	3404.0	3485.0	3428.8	2956.2	2124.2	1447.4	704.1	609.4	348.5	0.0	0.0	26.2	1290.7	1511.6
1931-32	1893.2	1800.3	1434.0	1034.7	808.2	48.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	3579.6	3579.1	3579.1	3378.4	3062.1	2520.3	1592.5	1185.9	1686.8	1065.7	448.8	1535.1	3123.9	3391.4
1929-30	3517.7	3554.7	3483.7	3172.7	2769.4	1761.1	617.5	709.9	1237.6	657.7	330.5	1367.5	2040.5	3039.9
1930-31	3178.8	3240.0	3239.0	2913.3	2720.5	1803.7	610.8	552.0	895.1	252.1	3.3	506.2	1293.2	2202.0
1931-32	1782.0	1611.4	1482.4	1348.1	807.8	161.6	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	705.8	703.8	705.5	540.6	350.4	290.6	126.6	125.0	105.1	113.5	121.0	238.5	513.3	700.2
1929-30	705.7	664.1	585.9	343.6	203.4	190.4	23.0	28.8	0.1	23.4	0.1	115.1	334.7	552.3
1930-31	579.7	500.7	486.1	263.4	139.7	120.9	103.0	50.0	10.0	23.2	0.0	157.2	128.0	52.2
1931-32	36.5	39.5	29.3	56.5	52.9	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	7814.6	7808.9	7813.2	7277.8	6351.6	5213.8	3371.8	2867.2	2892.0	1598.5	697.4	2143.0	5606.2	7280.7
1929-30	7751.7	7721.3	7500.3	6498.0	5115.0	3726.6	1668.4	1759.0	1785.9	681.1	330.6	1809.9	4337.3	6761.9
1930-31	7162.5	7225.7	7153.9	6132.9	4984.4	3372.0	1417.9	1211.4	1253.6	275.3	3.3	689.6	2711.9	3765.8
1931-32	3711.7	3451.2	2945.7	2439.3	1668.9	210.5	13.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 4
(English Units)
MICA
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2003 - 04 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	136.2	739.5	917.8	983.1	999.6	994.4	983.0	989.8	1015.0	973.2	1285.1	2460.4	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2086.5	1971.0	1931.7	1937.2	1978.0	2361.4	2931.3	3529.2
1929-30							1062.2	907.4	858.6	882.2	1038.7	1754.2	2647.1	*
1930-31							1321.8	1175.9	1122.5	1124.4	1214.5	1774.1	2722.3	*
1931-32							805.1	666.4	619.6	622.2	747.7	1472.0	2602.8	*
1932-33							708.0	604.7	575.3	575.8	653.4	1367.9	2439.4	*
1933-34							0.0	0.0	0.0	0.0	0.0	1114.3	2692.1	*
1934-35							1010.5	888.5	871.4	892.0	962.0	1582.7	2517.9	*
1935-36							796.3	674.7	646.2	646.2	741.6	1527.0	2776.9	*
1936-37							2074.7	1938.6	1884.6	1879.3	1968.0	2375.0	2963.6	*
1937-38							1082.1	960.4	913.6	920.7	1013.6	1694.7	2694.3	*
1938-39							1125.9	1048.4	1009.0	1036.8	1148.1	1797.4	2955.1	*
1939-40							905.7	791.6	769.4	791.0	920.5	1592.1	2714.9	*
1940-41							1503.7	1378.7	1344.8	1366.1	1543.4	2151.0	2945.1	*
1941-42							1519.1	1397.7	1355.6	1348.0	1424.0	2002.7	2847.4	*
1942-43							1714.4	1570.4	1525.4	1523.2	1675.7	2318.4	2932.7	*
1943-44							2182.0	2030.2	1989.8	1987.7	2056.2	2481.3	3102.3	*
1944-45							2098.7	1984.0	1957.4	1971.8	2021.2	2408.6	3021.3	*
1945-46							497.6	345.5	297.1	287.3	379.1	1163.8	2597.2	*
1946-47							620.5	522.1	502.5	514.4	630.8	1432.2	2667.7	*
1947-48							565.4	446.3	411.5	397.3	477.2	1223.6	2554.4	*
1948-49							2269.4	2124.8	2063.1	2060.6	2137.7	2606.9	3325.9	*
1949-50							920.9	762.3	703.9	694.4	778.9	1444.7	2365.7	*
1950-51							912.1	801.2	774.8	783.1	896.6	1563.8	2727.2	*
1951-52							1318.9	1165.4	1113.5	1098.4	1179.7	1859.2	2874.5	*
1952-53							1604.2	1468.5	1426.1	1423.8	1483.2	2018.4	2841.4	*
1953-54							475.9	352.4	334.7	338.4	422.0	1139.7	2337.8	*
1954-55							1247.6	1140.1	1114.2	1124.5	1210.7	1797.4	2532.2	*
1955-56							784.0	659.0	612.3	605.4	693.8	1461.7	2641.7	*
1956-57							952.6	820.3	788.2	793.6	882.6	1547.9	2972.3	*
1957-58							789.7	670.3	644.8	655.4	760.5	1448.1	2734.8	*
LIMITING RULE CURVE (KSFD)							519.0	265.9	21.5	0.0				
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES														
	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	10000	18000	21000	22000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							3000	3000	3000	3000	3000	5000	23400	25000
95 MAF --							3000	3000	3000	3000	3000	3000	23400	25000
110 MAF --							3000	3000	3000	3000	3000	3000	23000	25000

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2003 - 04 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	289.5	878.2	1672.8	1791.9	2330.4	2276.0	2250.3	2871.5	3545.2	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							2670.2	2561.0	2880.0	2952.4	3148.8	3579.6	3579.6	3579.6
1929-30							1632.5	1607.4	1610.5	1607.0	1881.1	3316.4	"	"
1930-31							1840.2	1770.8	1738.1	1831.1	2090.6	3153.8	"	"
1931-32							0.0	0.0	0.0	50.2	365.1	1942.7	3128.3	"
1932-33							578.3	556.9	530.6	537.3	741.1	2004.3	2930.1	"
1933-34							0.0	0.0	0.0	175.8	700.2	2324.6	3579.6	"
1934-35							952.0	960.8	1029.8	1067.0	1226.8	2547.0	3120.5	"
1935-36							1038.0	953.4	869.2	846.5	972.5	2487.2	3579.6	"
1936-37							2990.1	2828.1	3145.9	3179.5	3391.2	3579.6	"	"
1937-38							1121.9	1102.0	1080.3	1121.6	1364.5	2810.2	3463.6	"
1938-39							1768.3	1686.3	1628.1	1630.3	1975.3	3237.6	3579.6	"
1939-40							1495.6	1464.3	1461.2	1555.1	1796.6	3021.0	"	"
1940-41							2290.9	2253.2	2460.7	2671.7	3167.8	3579.6	"	"
1941-42							2117.8	2083.2	2304.9	2372.1	2669.2	"	"	"
1942-43							2359.3	2230.9	2581.2	2631.0	2988.5	"	"	"
1943-44							3496.2	3390.6	3579.6	3579.6	3579.6	"	"	"
1944-45							2841.6	2776.0	3149.7	3243.5	3428.0	"	"	"
1945-46							504.2	469.3	434.0	444.0	666.3	1908.4	3274.7	"
1946-47							1015.6	910.9	873.4	902.7	1136.8	2456.7	3430.7	"
1947-48							805.6	739.5	704.3	680.7	839.6	1987.8	3233.6	"
1948-49							2015.3	1907.8	2282.7	2360.9	2686.1	3579.6	3579.6	"
1949-50							719.6	661.9	649.9	659.3	845.1	2088.2	2811.7	"
1950-51							1008.1	998.5	993.6	969.8	1193.9	2545.9	3568.7	"
1951-52							1056.8	1002.7	995.6	1048.1	1343.3	2896.2	3579.6	"
1952-53							1455.4	1406.0	1706.5	1782.2	2028.5	3190.3	"	"
1953-54							198.2	216.6	236.6	261.9	448.8	1617.5	2799.8	"
1954-55							808.7	817.1	832.7	916.8	1242.2	2538.2	2852.6	"
1955-56							471.0	438.1	417.0	421.3	632.9	2146.9	3319.0	"
1956-57							523.3	472.4	442.7	435.7	652.8	2075.7	3579.6	"
1957-58							345.5	305.8	321.0	395.0	666.0	2015.1	3437.3	"
LIMITING RULE CURVE (KSFD)							517.6	277.2	60.0	0.2				
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES														
	5000	5000	5000	5000	5000	5000	5000	5000	5000	20000	25000	38000	53000	53000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							5000	5000	5000	5000	7000	10000	51700	52000
95 MAF --							5000	5000	5000	5000	5000	5000	51700	52000
110 MAF --							5000	5000	5000	5000	5000	5000	50000	52000

TABLE 6
(English Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2003 - 04 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	42.1	108.4	139.1	156.6	167.8	178.0	187.2	201.3	211.5	215.7	345.0	540.9	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							389.6	385.6	382.6	381.2	400.6	495.3	613.8	705.8
1929-30							388.0	383.6	380.3	378.6	412.2	515.8	625.3	"
1930-31							332.5	329.4	329.7	333.0	358.1	465.3	613.8	"
1931-32							56.2	54.4	62.1	70.3	112.8	279.8	525.8	"
1932-33							0.0	0.0	0.0	0.0	0.0	103.8	391.1	"
1933-34							45.7	61.0	74.0	88.2	158.8	338.6	583.9	"
1934-35							138.5	143.0	153.8	156.9	180.9	329.8	523.1	"
1935-36							89.8	88.8	89.5	90.2	117.1	302.8	557.3	"
1936-37							337.5	333.4	332.2	330.5	349.9	457.8	595.9	"
1937-38							126.8	132.3	137.7	145.0	175.8	334.9	550.4	"
1938-39							184.4	186.9	189.4	191.6	224.5	378.1	596.6	"
1939-40							167.7	175.6	185.5	197.3	231.8	380.2	585.1	"
1940-41							249.8	254.5	260.2	273.3	316.7	456.6	608.9	"
1941-42							245.6	252.6	258.6	262.8	289.6	424.4	588.8	"
1942-43							256.9	257.6	261.2	263.2	294.7	443.8	583.4	"
1943-44							405.8	407.1	409.0	409.6	431.2	528.0	644.0	"
1944-45							328.0	329.9	332.6	333.2	352.2	457.7	602.0	"
1945-46							2.7	0.2	3.6	5.9	39.0	225.2	519.2	"
1946-47							40.1	38.3	43.3	48.1	84.1	268.8	531.9	"
1947-48							83.1	85.9	92.1	93.5	120.2	284.7	542.3	"
1948-49							313.8	311.3	311.3	310.6	333.8	458.8	644.4	"
1949-50							114.8	113.5	116.3	116.2	140.7	293.3	486.3	"
1950-51							33.5	39.9	49.4	50.0	84.4	259.4	517.4	"
1951-52							144.3	144.4	150.4	151.8	178.6	343.4	562.6	"
1952-53							144.2	144.7	149.8	"	176.7	322.9	528.8	"
1953-54							0.0	0.0	0.0	0.0	9.0	187.3	459.3	"
1954-55							83.9	86.4	91.5	94.9	120.3	275.1	463.1	"
1955-56							0.0	0.0	0.0	1.6	33.1	233.3	515.1	"
1956-57							95.3	91.6	93.9	96.0	126.1	286.1	579.5	"
1957-58							5.0	4.6	11.3	15.9	47.9	225.0	531.3	"
LIMITING RULE CURVE (KSFD)							17.0	0.6	0.0	0.0				
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES														
	100	100	100	100	100	100	100	100	100	300	700	1000	1500	2000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							100	100	100	100	100	100	2900	3000
95 MAF --							100	100	100	100	100	100	2900	3000
110 MAF --							100	100	100	100	100	100	2800	3000

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2003 - 04 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	3428.4	3377.7	3332.1	3281.5	3281.5	3281.5	3352.6	3439.5	3529.2
1929-30	"	"	"	"	"	"	3348.3	3276.1	3195.9	3195.9	3195.9	3291.6	3408.6	"
1930-31	"	"	"	"	"	"	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	"
1931-32	"	"	"	"	"	"	3105.7	2803.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1932-33	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1933-34	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1934-35	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1935-36	"	"	"	"	"	"	3105.7	2803.2	"	"	"	"	"	"
1936-37	"	"	"	"	"	"	3325.9	3233.4	3130.9	3130.9	3130.9	3316.1	3393.8	"
1937-38	"	"	"	"	"	"	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1938-39	"	"	"	"	"	"	3190.1	2974.4	2736.1	2736.1	2736.1	2963.8	3242.1	"
1939-40	"	"	"	"	"	"	3263.0	3108.7	2943.4	2943.4	2943.4	3111.5	3317.1	"
1940-41	"	"	"	"	"	"	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	"
1941-42	"	"	"	"	"	"	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1942-43	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1943-44	"	"	"	"	"	"	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	"
1944-45	"	"	"	"	"	"	3177.0	2949.7	2698.3	2698.3	2698.3	2936.8	3228.4	"
1945-46	"	"	"	"	"	"	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1947-48	"	"	"	"	"	"	3105.7	2803.2	"	"	"	"	"	"
1948-49	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1951-52	"	"	"	"	"	"	3105.7	2803.2	"	"	"	"	"	"
1952-53	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1955-56	"	"	"	"	"	"	3105.7	2803.2	"	"	"	2695.5	3172.7	"
1956-57	"	"	"	"	"	"	3101.7	2807.2	"	"	"	2781.5	3149.6	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	"	"	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2003 - 04 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	3075.4	3059.9	3045.6	3030.1	3044.3	3069.1	3204.8	3579.6	3579.6
1929-30	"	"	"	"	"	"	2986.9	2906.5	2818.0	2837.8	2872.1	3060.2	"	"
1930-31	"	"	"	"	"	"	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	"	"
1931-32	"	"	"	"	"	"	2371.6	1712.7	1008.3	1016.0	1126.6	2224.5	"	"
1932-33	"	"	"	"	"	"	2363.5	1720.2	"	1008.3	1036.6	1761.7	3034.5	"
1933-34	"	"	"	"	"	"	"	"	"	"	1784.9	2327.4	3579.6	"
1934-35	"	"	"	"	"	"	"	"	"	"	1008.3	1725.7	3034.5	"
1935-36	"	"	"	"	"	"	2371.6	1712.7	"	1070.0	1373.5	2134.5	3579.6	"
1936-37	"	"	"	"	"	"	2928.6	2795.7	2648.9	2673.1	2723.4	3253.9	"	"
1937-38	"	"	"	"	"	"	2363.5	1720.2	1008.3	1082.9	1278.3	1831.1	3147.6	"
1938-39	"	"	"	"	"	"	2574.9	2123.0	1622.5	1692.9	1818.2	2648.0	3579.6	"
1939-40	"	"	"	"	"	"	2764.0	2472.7	2161.3	2203.8	2303.1	2870.4	"	"
1940-41	"	"	"	"	"	"	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	"	"
1941-42	"	"	"	"	"	"	2363.5	1720.2	1008.3	1064.9	1149.8	1934.0	"	"
1942-43	"	"	"	"	"	"	"	"	"	1111.2	1322.0	1440.3	2389.1	"
1943-44	"	"	"	"	"	"	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	"
1944-45	"	"	"	"	"	"	2543.4	2063.1	1531.1	1559.7	1635.5	2297.2	3333.8	"
1945-46	"	"	"	"	"	"	2363.5	1720.2	1008.3	1072.6	1242.3	2201.4	3579.6	"
1946-47	"	"	"	"	"	"	"	"	"	1075.2	1360.6	2147.4	"	"
1947-48	"	"	"	"	"	"	2371.6	1712.7	"	1036.6	1183.2	2216.8	"	"
1948-49	"	"	"	"	"	"	2363.5	1720.2	"	1144.6	1376.0	2494.5	"	"
1949-50	"	"	"	"	"	"	"	"	"	1008.3	1008.3	1113.8	2232.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	1355.5	3337.9	"
1951-52	"	"	"	"	"	"	2371.6	1712.7	"	1070.0	1345.2	1792.6	3013.9	"
1952-53	"	"	"	"	"	"	2363.5	1720.2	"	1057.2	1172.9	1476.3	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	1134.3	1628.0	1898.0	"
1954-55	"	"	"	"	"	"	"	"	"	1075.2	1090.6	1653.7	3224.8	"
1955-56	"	"	"	"	"	"	2371.6	1712.7	"	1008.3	1216.6	1990.6	2993.4	"
1956-57	"	"	"	"	"	"	2363.5	1720.2	"	1077.8	1224.3	2651.4	3579.6	"
1957-58	"	"	"	"	"	"	"	"	"	1046.9	1190.9	2242.5	"	"

TABLE 9
(English Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2003 - 04 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	443.3	574.2	705.8
1929-30	"	"	"	"	"	"	408.7	322.6	322.6	322.6	322.6	430.7	567.9	"
1930-31	"	"	"	"	"	"	390.7	288.3	288.3	288.3	288.3	406.1	555.5	"
1931-32	"	"	"	"	"	"	277.3	65.5	65.5	65.5	65.5	281.3	609.8	"
1932-33	"	"	"	"	"	"	273.7	"	"	"	"	191.6	573.3	"
1933-34	"	"	"	"	"	"	"	"	"	"	127.0	339.6	605.3	"
1934-35	"	"	"	"	"	"	"	"	"	"	65.5	187.2	488.1	"
1935-36	"	"	"	"	"	"	277.3	"	"	"	"	351.7	705.8	"
1936-37	"	"	"	"	"	"	378.0	264.1	264.1	264.1	264.1	388.7	546.8	"
1937-38	"	"	"	"	"	"	293.6	103.3	103.3	103.3	103.3	246.1	552.2	"
1938-39	"	"	"	"	"	"	287.7	92.2	92.2	92.2	92.2	399.0	705.8	"
1939-40	"	"	"	"	"	"	303.0	114.9	114.9	114.9	114.9	410.4	"	"
1940-41	"	"	"	"	"	"	345.5	202.1	202.1	202.1	202.1	344.2	524.5	"
1941-42	"	"	"	"	"	"	329.3	171.4	171.4	171.4	171.4	439.6	705.8	"
1942-43	"	"	"	"	"	"	332.5	177.4	177.4	177.4	220.2	288.4	653.0	"
1943-44	"	"	"	"	"	"	416.4	334.7	334.7	334.7	334.7	439.4	572.2	"
1944-45	"	"	"	"	"	"	384.6	276.8	276.8	276.8	276.8	493.4	705.8	"
1945-46	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	322.3	647.5	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	314.0	629.6	"
1947-48	"	"	"	"	"	"	277.3	"	"	"	"	300.5	705.8	"
1948-49	"	"	"	"	"	"	370.9	250.5	250.5	256.4	276.5	434.0	"	"
1949-50	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	183.9	525.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	285.1	534.2	"
1951-52	"	"	"	"	"	"	277.3	"	"	"	"	220.4	383.1	"
1952-53	"	"	"	"	"	"	273.7	"	"	"	"	234.6	522.7	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	237.1	547.6	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	154.5	488.8	"
1955-56	"	"	"	"	"	"	277.3	"	"	"	84.7	266.6	585.4	"
1956-57	"	"	"	"	"	"	273.7	"	"	"	65.5	376.0	655.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	359.4	705.8	"

TABLE 10
(English Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2003 - 04 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7808.9	7813.2	7277.8	6351.6	5213.8	3503.5	3535.4	3631.8	3502.5	3439.2	4501.6	6546.5	7814.6
1929-30	"	"	"	"	"	"	2872.7	2702.0	2670.4	2700.7	3070.0	4501.6	6546.5	"
1930-31	"	"	"	"	"	"	3172.6	3133.9	3039.5	3057.6	3279.5	4501.6	6546.5	"
1931-32	"	"	"	"	"	"	1378.9	998.0	741.7	737.9	1178.3	3507.6	6114.5	"
1932-33	"	"	"	"	"	"	1303.3	1162.2	1105.9	1113.1	1394.5	3150.6	5760.6	"
1933-34	"	"	"	"	"	"	1082.3	604.1	155.5	264.0	827.2	3777.5	6546.5	"
1934-35	"	"	"	"	"	"	2101.0	1992.3	2055.0	2115.9	2035.8	3198.0	5983.0	"
1935-36	"	"	"	"	"	"	1924.1	1716.9	1604.9	1582.9	1831.2	3722.4	6546.5	"
1936-37	"	"	"	"	"	"	3503.5	3535.4	3631.8	3502.5	3439.2	4501.6	6546.5	"
1937-38	"	"	"	"	"	"	2330.8	2165.7	2025.2	2106.9	2354.8	3362.3	6148.9	"
1938-39	"	"	"	"	"	"	2976.7	2826.9	2723.7	2737.5	2883.6	4278.1	6546.5	"
1939-40	"	"	"	"	"	"	2569.0	2370.8	2345.5	2461.0	2832.0	4500.5	6546.5	"
1940-41	"	"	"	"	"	"	3354.5	3357.8	3631.8	3493.1	3425.6	4500.8	6530.1	"
1941-42	"	"	"	"	"	"	3369.9	3289.3	2279.8	2251.3	2294.4	3564.1	6546.5	"
1942-43	"	"	"	"	"	"	3503.5	3525.6	3607.9	2303.6	2510.9	3013.8	5390.4	"
1943-44	"	"	"	"	"	"	3503.5	3535.4	3631.8	3502.5	3439.2	4501.6	6546.5	"
1944-45	"	"	"	"	"	"	3503.5	3535.4	2832.5	2786.2	2824.4	3927.3	6335.1	"
1945-46	"	"	"	"	"	"	1053.6	815.4	734.7	737.2	1084.4	3297.4	6254.3	"
1946-47	"	"	"	"	"	"	1676.2	1471.3	1419.2	1465.2	1851.7	3701.3	6423.0	"
1947-48	"	"	"	"	"	"	1454.1	1271.7	1207.9	1171.5	1437.0	3496.1	6234.9	"
1948-49	"	"	"	"	"	"	3503.5	3463.7	3584.1	2371.1	2564.9	4124.6	6546.5	"
1949-50	"	"	"	"	"	"	1755.3	1489.7	1419.3	1419.2	1689.5	2582.8	5084.3	"
1950-51	"	"	"	"	"	"	1953.7	1839.6	1817.8	1802.9	2174.9	2900.0	6315.7	"
1951-52	"	"	"	"	"	"	2520.0	2312.5	2246.1	2214.9	2495.1	3298.1	5857.4	"
1952-53	"	"	"	"	"	"	3203.8	3019.2	2956.4	2224.0	2322.8	2996.0	6528.3	"
1953-54	"	"	"	"	"	"	1053.6	630.2	571.3	600.3	879.8	2944.5	4695.1	"
1954-55	"	"	"	"	"	"	2140.2	2043.6	2024.3	2026.7	2184.1	3093.3	5776.1	"
1955-56	"	"	"	"	"	"	1318.6	1097.7	1029.3	1028.3	1359.8	3509.0	5968.9	"
1956-57	"	"	"	"	"	"	1571.2	1384.3	1324.8	1325.3	1600.9	3646.9	6546.5	"
1957-58	"	"	"	"	"	"	1324.3	980.7	977.1	1066.3	1474.4	3525.2	6429.0	"

TABLE 11
(English Units)
COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	1999-00	2000-01	2001-02	2002-03	2003-04
MICA TARGET OPERATION					
(ksfd[xxxx.x] or cfs [xxxxx])					
AUG 15	3456.2	3486.2	3486.2	3486.2	3499.2
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	3428.2	3386.2	3396.2	3396.2	3374.1
NOV	3176.2	3056.2	20000	20000	20000
DEC	24000	25000	22000	22000	23000
JAN	25000	26000	24000	24000	25000
FEB	22000	23000	21000	21000	21000
MAR	21000	22000	22000	18000	19000
APR 15	156.2	26000	326.2	281.3	204.1
APR 30	106.2	106.2	56.2	15000	15000
MAY	10000	8000	10000	10000	10000
JUN	10000	8000	10000	10000	10000
JUL	3456.2	3456.2	3456.2	3456.2	3449.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7814.6	7814.6	7806.2	7811.1	7808.9
1928 DEC	5618.4	5402.7	5310.4	5811.1	5213.8
1929 APR15	1763.1	1597.9	1458.7	1452.6	1598.5
1929 JUL	6916.0	7116.1	7453.0	7426.8	7280.7
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)					
50-yr Average for AOP00~AOP02, 60-yr average for AOP03 & AOP04					
AUG 31	7295.4	7389.8	7412.3	7414.6	7415.0
DEC	5283.1	5157.8	5236.9	5226.9	4759.5
APR15	1424.0	1150.7	1135.3	1173.1	1097.7
JUL	7099.3	7273.7	7358.2	7339.0	7262.0
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-1.5	-0.3	0.2	-0.3	-1.2
U.S. Dependable Peaking Capacity	0.0	-2.0	0.0	-18.0	16.0
U.S. Average Annual Usable Secondary Energy	19.5	16.2	24.9	3.7	12.9
BCH Firm Energy	102.2	60.8	48.3	30.3	43.1
BCH Dependable Peaking Capacity	-3.0	-36.0	25.0	26.0	8.0
BCH Average Annual Usable Secondary Energy	-42.9	-43.6	-29.7	-17.3	-24.3
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	9793	10043	10422	10368	10439
AUG 31	9925	10125	10439	10355	10435
SEP	9630	10095	10434	9911	10101
OCT	9764	10046	10388	10051	10186
NOV	11297	11381	11626	11716	11807
DEC	12766	12836	13012	13160	13377
JAN	13725	13484	13382	13707	13122
FEB	12674	12765	12502	12694	12240
MAR	12113	11807	11667	11858	11175
APR 15	11099	11332	11187	11460	10541
APR 30	12672	13025	12575	13101	13065
MAY	17263	14347	14647	14357	13752
JUN	14699	11925	12590	13324	13114
JUL	9894	11275	10493	10457	12079
ANNUAL AVERAGE	12131	11850	11919	11986	11933

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2003-04 ASSURED OPERATING PLAN

Period	End of Previous Period Arrow Storage Content (hm³)	Target Operation: Period Average Outflow (m³/s)	Target Operation: End-of-Period Treaty Content 1/ (hm³)	Minimum Outflow (m³/s)	Minimum Treaty Storage Content 2/ (hm³)
August 1-15	6361.2 - FULL	-	8561.1	424.75	0.0
	4036.9 - 6361.2	707.92			
	0.0 - 4036.9	849.50			
August 16-31	8318.4 - FULL	-	8634.5	424.75	0.0
	3547.6 - 8318.4	707.92			
	0.0 - 3547.6	877.82			
September	8465.2 - FULL	-	8634.5	283.17	0.0
	4575.1 - 8465.2	622.97			
	2128.5 - 4575.1	764.55			
	0.0 - 2128.5	877.82			
October	7890.3 - FULL	-	8255.1	283.17	0.0
	6189.9 - 7890.3	594.65			
	4746.4 - 6189.9	651.29			
	0.0 - 4746.4	906.14			
November	8061.5 - FULL	566.34		339.80	0.0
	6495.7 - 8061.5	622.97			
	3449.7 - 6495.7	679.60			
	0.0 - 3449.7	906.14			
December	7364.3 - FULL	651.29		594.65	499.4
	4636.3 - 7364.3	707.92			
	3376.3 - 4636.3	764.55			
	0.0 - 3376.3	906.14			
January	6141.0 - FULL	707.92		424.75	223.4
	3376.3 - 6141.0	792.87			
	3033.8 - 3376.3	736.24			
	0.0 - 3033.8	792.87			
February	2935.9 - FULL	594.65		424.75	0.0
	166.4 - 2935.9	651.29			
	127.2 - 166.4	566.34			
	0.0 - 127.2	679.60			
March	3743.3 - FULL	538.02		424.75	0.0
	2104.1 - 3743.3	707.92			
	905.2 - 2104.1	538.02			
	0.0 - 905.2	736.24			
April 1-15	4061.4 - FULL	-	499.4	368.12	0.0
	2373.2 - 4061.4	-	10.0		
	2287.6 - 2373.2	679.60			
	0.0 - 2287.6	-	328.1		
April 16-30	3033.8 - FULL	424.75		424.75	0.0
	2201.9 - 3033.8	339.80			
	489.3 - 2201.9		0.0		
	0.0 - 489.3	396.44			
May	1908.3 - FULL	283.17		226.53	0.0
	599.4 - 1908.3	226.53			
	293.6 - 599.4	481.39			
	0.0 - 293.6	396.44			
June	3841.2 - FULL	283.17		226.53	0.0
	2568.9 - 3841.2	226.53			
	782.9 - 2568.9	283.17			
	0.0 - 782.9	594.65			
July	4746.4 - FULL	-	8438.8	226.53	0.0
	4452.8 - 4746.4	538.02			
	4159.2 - 4452.8	339.80			
	0.0 - 4159.2	764.55			

1/ A maximum outflow of 962.77 m³/s will apply if the target end-of-period storage content @ Mica is less than 8634.5 hm³ in every month except April 16-30, May, and June. For these periods, the maximum outflow is 764.55 m³/s in April 16-30, 849.50 m3/s in May and 934.46 m³/s in June.

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 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2003 - 04 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8626.7	8633.1	8217.6	7190.8	5878.9	4043.5	3807.6	2691.5	1025.9	312.2	903.8	4817.4	7802.5
1929-30	8632.3	8569.2	8393.6	7295.0	5241.1	4343.0	2514.9	2496.3	1341.2	0.0	0.0	800.8	4800.5	7755.0
1930-31	8328.2	8526.4	8388.9	7232.6	5197.1	3541.2	1722.7	1491.0	852.6	0.0	0.0	64.1	3157.8	3698.3
1931-32	4631.9	4404.6	3508.4	2531.5	1977.3	118.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	8757.8	8756.6	8756.6	8265.6	7491.7	6166.2	3896.2	2901.4	4126.9	2607.3	1098.0	3755.8	7642.9	8297.4
1929-30	8606.4	8696.9	8523.2	7762.3	6775.6	4308.7	1510.8	1736.8	3027.9	1609.1	808.6	3345.7	4992.3	7437.4
1930-31	7777.3	7927.0	7924.5	7127.7	6656.0	4412.9	1494.4	1350.5	2190.0	616.8	8.1	1238.5	3163.9	5387.4
1931-32	4359.8	3942.5	3626.8	3298.3	1976.4	395.4	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	1726.8	1721.9	1726.1	1322.6	857.3	711.0	309.7	305.8	257.1	277.7	296.0	583.5	1255.8	1713.1
1929-30	1726.6	1624.8	1433.5	840.7	497.6	465.8	56.3	70.5	0.2	57.3	0.2	281.6	818.9	1351.3
1930-31	1418.3	1225.0	1189.3	644.4	341.8	295.8	252.0	122.3	24.5	56.8	0.0	384.6	313.2	127.7
1931-32	89.3	96.6	71.7	138.2	129.4	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	19119.2	19105.3	19115.8	17805.9	15539.8	12756.1	8249.4	7014.9	7075.6	3910.9	1706.3	5243.1	13716.1	17813.0
1929-30	18965.3	18890.9	18350.2	15898.0	12514.4	9117.5	4081.9	4303.6	4369.4	1666.4	808.8	4428.1	10611.6	16543.7
1930-31	17523.8	17678.4	17502.7	15004.8	12194.8	8249.9	3469.0	2963.8	3067.1	673.5	8.1	1687.2	6634.9	9213.4
1931-32	9081.0	8443.7	7206.9	5968.0	4083.1	515.0	33.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 4M
(Metric Units)
MICA
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2003 - 04 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	333.2	1809.3	2245.5	2405.3	2445.6	2432.9	2405.0	2421.6	2483.3	2381.0	3144.1	6019.6	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							5104.8	4822.2	4726.1	4739.6	4839.4	5777.4	7171.7	8634.5
1929-30							2598.8	2220.0	2100.7	2158.4	2541.3	4291.8	6476.4	*
1930-31							3233.9	2877.0	2746.3	2751.0	2971.4	4340.5	6660.4	*
1931-32							1969.8	1630.4	1515.9	1522.3	1829.3	3601.4	6368.0	*
1932-33							1732.2	1479.5	1407.5	1408.8	1598.6	3346.7	5968.2	*
1933-34							0.0	0.0	0.0	0.0	0.0	2726.2	6586.5	*
1934-35							2472.3	2173.8	2132.0	2182.4	2353.6	3872.2	6160.3	*
1935-36							1948.2	1650.7	1581.0	1581.0	1814.4	3736.0	6794.0	*
1936-37							5076.0	4743.0	4610.9	4597.9	4814.9	5810.7	7250.7	*
1937-38							2647.5	2349.7	2235.2	2252.6	2479.9	4146.3	6591.9	*
1938-39							2754.6	2565.0	2468.6	2536.6	2808.9	4397.5	7229.9	*
1939-40							2215.9	1936.7	1882.4	1935.3	2252.1	3895.2	6642.3	*
1940-41							3679.0	3373.1	3290.2	3342.3	3776.1	5262.6	7205.5	*
1941-42							3716.6	3419.6	3316.6	3298.0	3484.0	4899.8	6966.4	*
1942-43							4194.5	3842.1	3732.0	3726.7	4099.8	5672.2	7175.1	*
1943-44							5338.5	4967.1	4868.2	4863.1	5030.7	6070.7	7590.1	*
1944-45							5134.7	4854.1	4789.0	4824.2	4945.1	5892.9	7391.9	*
1945-46							1217.4	845.3	726.9	702.9	927.5	2847.4	6354.3	*
1946-47							1518.1	1277.4	1229.4	1258.5	1543.3	3504.0	6526.8	*
1947-48							1383.3	1091.9	1006.8	972.0	1167.5	2993.7	6249.6	*
1948-49							5552.3	5198.5	5047.6	5041.5	5230.1	6378.0	8137.1	*
1949-50							2253.1	1865.0	1722.2	1698.9	1905.7	3534.6	5787.9	*
1950-51							2231.5	1960.2	1895.6	1915.9	2193.6	3826.0	6672.4	*
1951-52							3226.8	2851.3	2724.3	2687.3	2886.3	4548.7	7032.8	*
1952-53							3924.8	3592.8	3489.1	3483.5	3628.8	4938.2	6951.8	*
1953-54							1164.3	862.2	818.9	827.9	1032.5	2788.4	5719.7	*
1954-55							3052.4	2789.4	2726.0	2751.2	2962.1	4397.5	6195.3	*
1955-56							1918.1	1612.3	1498.1	1481.2	1697.5	3576.2	6463.2	*
1956-57							2330.6	2006.9	1928.4	1941.6	2159.4	3787.1	7272.0	*
1957-58							1932.1	1640.0	1577.6	1603.5	1860.6	3542.9	6691.0	*
LIMITING RULE CURVE (hm^3)							1269.8	650.6	52.6	0.0				

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	283.17	509.70	594.65	622.97
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							84.95	84.95	84.95	84.95	84.95	141.58	662.61	707.92
117.18 km^3 --							84.95	84.95	84.95	84.95	84.95	84.95	662.61	707.92
135.69 km^3 --							84.95	84.95	84.95	84.95	84.95	84.95	651.29	707.92

TABLE 5M
(Metric Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2003 - 04 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	708.3	2148.6	4092.7	4384.1	5701.6	5568.5	5505.6	7025.4	8673.7	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							6532.9	6265.7	7046.2	7223.3	7703.9	8757.8	8757.8	8757.8
1929-30							3994.1	3932.7	3940.2	3931.7	4602.3	8113.9	"	"
1930-31							4502.2	4332.4	4252.4	4480.0	5114.9	7716.1	"	"
1931-32							0.0	0.0	0.0	122.8	893.3	4753.0	7653.7	"
1932-33							1414.9	1362.5	1298.2	1314.6	1813.2	4903.7	7168.8	"
1933-34							0.0	0.0	0.0	430.1	1713.1	5687.4	8757.8	"
1934-35							2329.2	2350.7	2519.5	2610.5	3001.5	6231.5	7634.6	"
1935-36							2539.6	2332.6	2126.6	2071.0	2379.3	6085.2	8757.8	"
1936-37							7315.6	6919.2	7696.8	7779.0	8296.9	8757.8	"	"
1937-38							2744.8	2696.2	2643.1	2744.1	3338.4	6875.4	8474.0	"
1938-39							4326.3	4125.7	3983.3	3988.7	4832.8	7921.1	8757.8	"
1939-40							3659.1	3582.6	3575.0	3804.7	4395.6	7391.2	"	"
1940-41							5604.9	5512.7	6020.3	6536.6	7750.3	8757.8	"	"
1941-42							5181.4	5096.8	5639.2	5803.6	6530.5	"	"	"
1942-43							5772.3	5458.1	6315.2	6437.0	7311.7	"	"	"
1943-44							8553.8	8295.4	8757.8	8757.8	8757.8	"	"	"
1944-45							6952.3	6791.8	7706.1	7935.5	8386.9	"	"	"
1945-46							1233.6	1148.2	1061.8	1086.3	1630.2	4669.1	8011.9	"
1946-47							2484.8	2228.6	2136.9	2208.5	2781.3	6010.6	8393.6	"
1947-48							1971.0	1809.3	1723.1	1665.4	2054.2	4863.4	7911.3	"
1948-49							4930.6	4667.6	5584.9	5776.2	6571.8	8757.8	8757.8	"
1949-50							1760.6	1619.4	1590.0	1613.0	2067.6	5109.0	6879.1	"
1950-51							2466.4	2442.9	2430.9	2372.7	2921.0	6228.8	8731.2	"
1951-52							2585.6	2453.2	2435.8	2564.3	3286.5	7085.8	8757.8	"
1952-53							3560.8	3439.9	4175.1	4360.3	4962.9	7805.4	"	"
1953-54							484.9	529.9	578.9	640.8	1098.0	3957.4	6850.0	"
1954-55							1978.6	1999.1	2037.3	2243.0	3039.2	6210.0	6979.2	"
1955-56							1152.3	1071.9	1020.2	1030.8	1548.5	5252.6	8120.3	"
1956-57							1280.3	1155.8	1083.1	1066.0	1597.1	5078.4	8757.8	"
1957-58							845.3	748.2	785.4	966.4	1629.4	4930.1	8409.7	"
LIMITING RULE CURVE (hm^3)							1266.4	678.2	146.8	0.5				

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	566.34	707.92	1076.04	1500.79	1500.79
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
					98.68 km^3 --		141.58	141.58	141.58	141.58	198.22	283.17	1463.98	1472.47
					117.18 km^3 --		141.58	141.58	141.58	141.58	141.58	141.58	1463.98	1472.47
					135.69 km^3 --		141.58	141.58	141.58	141.58	141.58	141.58	1415.84	1472.47

TABLE 6M
(Metric Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2003 - 04 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	103.0	265.2	340.3	383.1	410.5	435.5	458.0	492.5	517.5	527.7	844.1	1323.4	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							953.2	943.4	936.1	932.6	980.1	1211.8	1501.7	1726.8
1929-30							949.3	938.5	930.4	926.3	1008.5	1262.0	1529.9	"
1930-31							813.5	805.9	806.6	814.7	876.1	1138.4	1501.7	"
1931-32							137.5	133.1	151.9	172.0	276.0	684.6	1286.4	"
1932-33							0.0	0.0	0.0	0.0	0.0	254.0	956.9	"
1933-34							111.8	149.2	181.0	215.8	388.5	828.4	1428.6	"
1934-35							338.9	349.9	376.3	383.9	442.6	806.9	1279.8	"
1935-36							219.7	217.3	219.0	220.7	286.5	740.8	1363.5	"
1936-37							825.7	815.7	812.8	808.6	856.1	1120.1	1457.9	"
1937-38							310.2	323.7	336.9	354.8	430.1	819.4	1346.6	"
1938-39							451.2	457.3	463.4	468.8	549.3	925.1	1459.6	"
1939-40							410.3	429.6	453.8	482.7	567.1	930.2	1431.5	"
1940-41							611.2	622.7	636.6	668.7	774.8	1117.1	1489.7	"
1941-42							600.9	618.0	632.7	643.0	708.5	1038.3	1440.6	"
1942-43							628.5	630.2	639.1	643.9	721.0	1085.8	1427.3	"
1943-44							992.8	996.0	1000.7	1002.1	1055.0	1291.8	1575.6	"
1944-45							802.5	807.1	813.7	815.2	861.7	1119.8	1472.9	"
1945-46							6.6	0.5	8.8	14.4	95.4	551.0	1270.3	"
1946-47							98.1	93.7	105.9	117.7	205.8	657.6	1301.3	"
1947-48							203.3	210.2	225.3	228.8	294.1	696.5	1326.8	"
1948-49							767.7	761.6	761.6	759.9	816.7	1122.5	1576.6	"
1949-50							280.9	277.7	284.5	284.3	344.2	717.6	1189.8	"
1950-51							82.0	97.6	120.9	122.3	206.5	634.6	1265.9	"
1951-52							353.0	353.3	368.0	371.4	437.0	840.2	1376.5	"
1952-53							352.8	354.0	366.5	"	432.3	790.0	1293.8	"
1953-54							0.0	0.0	0.0	0.0	22.0	458.2	1123.7	"
1954-55							205.3	211.4	223.9	232.2	294.3	673.1	1133.0	"
1955-56							0.0	0.0	0.0	3.9	81.0	570.8	1260.2	"
1956-57							233.2	224.1	229.7	234.9	308.5	700.0	1417.8	"
1957-58							12.2	11.3	27.6	38.9	117.2	550.5	1299.9	"
LIMITING RULE CURVE (hm^3)							41.6	1.5	0.0	0.0				

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	8.50	19.82	28.32	42.48	56.63
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							2.83	2.83	2.83	2.83	2.83	2.83	82.12	84.95
117.18 km^3 --							2.83	2.83	2.83	2.83	2.83	2.83	82.12	84.95
135.69 km^3 --							2.83	2.83	2.83	2.83	2.83	2.83	79.29	84.95

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2003 - 04 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8634.5	8634.5	8634.5	8387.9	8387.9	8387.9	8263.9	8152.3	8028.5	8028.5	8028.5	8202.5	8415.1	8634.5
1929-30	"	"	"	"	"	"	8192.0	8015.3	7819.1	7819.1	7819.1	8053.2	8339.5	"
1930-31	"	"	"	"	"	"	8387.9	8387.9	8387.9	8387.9	8387.9	8458.6	8545.2	"
1931-32	"	"	"	"	"	"	7598.4	6858.3	6068.8	6068.8	6068.8	6805.2	7705.8	"
1932-33	"	"	"	"	"	"	7588.6	6868.1	"	"	"	"	"	"
1933-34	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1934-35	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1935-36	"	"	"	"	"	"	7598.4	6858.3	"	"	"	"	"	"
1936-37	"	"	"	"	"	"	8137.1	7910.8	7660.1	7660.1	7660.1	8113.2	8303.3	"
1937-38	"	"	"	"	"	"	7588.6	6868.1	6068.8	6068.8	6068.8	6805.2	7705.8	"
1938-39	"	"	"	"	"	"	7804.9	7277.2	6694.1	6694.1	6694.1	7251.2	7932.1	"
1939-40	"	"	"	"	"	"	7983.3	7605.7	7201.3	7201.3	7201.3	7612.6	8115.6	"
1940-41	"	"	"	"	"	"	8387.9	8387.9	8387.9	8387.9	8387.9	8458.6	8545.2	"
1941-42	"	"	"	"	"	"	7588.6	6868.1	6068.8	6068.8	6068.8	6805.2	7705.8	"
1942-43	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1943-44	"	"	"	"	"	"	8387.9	8387.9	8387.9	8387.9	8387.9	8458.6	8545.2	"
1944-45	"	"	"	"	"	"	7772.8	7216.7	6601.7	6601.7	6601.7	7185.2	7898.6	"
1945-46	"	"	"	"	"	"	7588.6	6868.1	6068.8	6068.8	6068.8	6805.2	7705.8	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1947-48	"	"	"	"	"	"	7598.4	6858.3	"	"	"	"	"	"
1948-49	"	"	"	"	"	"	7588.6	6868.1	"	"	"	"	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1951-52	"	"	"	"	"	"	7598.4	6858.3	"	"	"	"	"	"
1952-53	"	"	"	"	"	"	7588.6	6868.1	"	"	"	"	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1955-56	"	"	"	"	"	"	7598.4	6858.3	"	"	"	6594.8	7762.3	"
1956-57	"	"	"	"	"	"	7588.6	6868.1	"	"	"	6805.2	7705.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	"	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2003 - 04 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8757.8	8757.8	8757.8	8449.6	8449.6	7524.3	7486.4	7451.4	7413.4	7448.2	7508.9	7840.9	8757.8	8757.8
1929-30	"	"	"	"	"	"	7307.7	7111.0	6894.5	6943.0	7026.9	7487.1	"	"
1930-31	"	"	"	"	"	"	7524.3	7524.3	7524.3	7556.3	7611.9	7916.7	"	"
1931-32	"	"	"	"	"	"	5802.4	4190.3	2466.9	2485.7	2756.3	5442.5	"	"
1932-33	"	"	"	"	"	"	5782.5	4208.6	"	2466.9	2536.1	4310.2	7424.2	"
1933-34	"	"	"	"	"	"	"	"	"	"	4366.9	5694.2	8757.8	"
1934-35	"	"	"	"	"	"	"	"	"	"	2466.9	4222.1	7424.2	"
1935-36	"	"	"	"	"	"	5802.4	4190.3	"	2617.9	3360.4	5222.3	8757.8	"
1936-37	"	"	"	"	"	"	7165.1	6840.0	6480.8	6540.0	6663.1	7961.0	"	"
1937-38	"	"	"	"	"	"	5782.5	4208.6	2466.9	2649.4	3127.5	4480.0	7700.9	"
1938-39	"	"	"	"	"	"	6299.8	5194.1	3969.6	4141.8	4448.4	6478.6	8757.8	"
1939-40	"	"	"	"	"	"	6762.4	6049.7	5287.8	5391.8	5634.8	7022.7	"	"
1940-41	"	"	"	"	"	"	7524.3	7524.3	7524.3	7556.3	7611.9	7916.7	"	"
1941-42	"	"	"	"	"	"	5782.5	4208.6	2466.9	2605.4	2813.1	4731.7	"	"
1942-43	"	"	"	"	"	"	"	"	"	2718.7	3234.4	3523.8	5845.2	"
1943-44	"	"	"	"	"	"	7524.3	7524.3	7524.3	7556.3	7611.9	7916.7	8757.8	"
1944-45	"	"	"	"	"	"	6222.7	5047.6	3746.0	3816.0	4001.4	5620.3	8156.5	"
1945-46	"	"	"	"	"	"	5782.5	4208.6	2466.9	2624.2	3039.4	5385.9	8757.8	"
1946-47	"	"	"	"	"	"	"	"	"	2630.6	3328.8	5253.8	"	"
1947-48	"	"	"	"	"	"	5802.4	4190.3	"	2536.1	2894.8	5423.6	"	"
1948-49	"	"	"	"	"	"	5782.5	4208.6	"	2800.4	3366.5	6103.0	"	"
1949-50	"	"	"	"	"	"	"	"	"	2466.9	2466.9	2725.0	5461.5	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	3316.4	8166.5	"
1951-52	"	"	"	"	"	"	5802.4	4190.3	"	2617.9	3291.2	4385.8	7373.8	"
1952-53	"	"	"	"	"	"	5782.5	4208.6	"	2586.5	2869.6	3611.9	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	2775.2	3983.1	4643.6	"
1954-55	"	"	"	"	"	"	"	"	"	2630.6	2668.3	4045.9	7889.8	"
1955-56	"	"	"	"	"	"	5802.4	4190.3	"	2466.9	2976.5	4870.2	7323.7	"
1956-57	"	"	"	"	"	"	5782.5	4208.6	"	2636.9	2995.4	6486.9	8757.8	"
1957-58	"	"	"	"	"	"	"	"	"	2561.3	2913.7	5486.5	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2003 - 04 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	1084.6	1404.8	1726.8
1929-30	*	*	*	*	*	*	999.9	789.3	789.3	789.3	789.3	1053.8	1389.4	*
1930-31	*	*	*	*	*	*	955.9	705.4	705.4	705.4	705.4	993.6	1359.1	*
1931-32	*	*	*	*	*	*	678.4	160.3	160.3	160.3	160.3	688.2	1491.9	*
1932-33	*	*	*	*	*	*	669.6	*	*	*	*	468.8	1402.6	*
1933-34	*	*	*	*	*	*	*	*	*	*	310.7	830.9	1480.9	*
1934-35	*	*	*	*	*	*	*	*	*	*	160.3	458.0	1194.2	*
1935-36	*	*	*	*	*	*	678.4	*	*	*	*	860.5	1726.8	*
1936-37	*	*	*	*	*	*	924.8	646.1	646.1	646.1	646.1	951.0	1337.8	*
1937-38	*	*	*	*	*	*	718.3	252.7	252.7	252.7	252.7	602.1	1351.0	*
1938-39	*	*	*	*	*	*	703.9	225.6	225.6	225.6	225.6	976.2	1726.8	*
1939-40	*	*	*	*	*	*	741.3	281.1	281.1	281.1	281.1	1004.1	*	*
1940-41	*	*	*	*	*	*	845.3	494.5	494.5	494.5	494.5	842.1	1283.2	*
1941-42	*	*	*	*	*	*	805.7	419.3	419.3	419.3	419.3	1075.5	1726.8	*
1942-43	*	*	*	*	*	*	813.5	434.0	434.0	434.0	538.7	705.6	1597.6	*
1943-44	*	*	*	*	*	*	1018.8	818.9	818.9	818.9	818.9	1075.0	1399.9	*
1944-45	*	*	*	*	*	*	941.0	677.2	677.2	677.2	677.2	1207.2	1726.8	*
1945-46	*	*	*	*	*	*	669.6	160.3	160.3	160.3	160.3	788.5	1584.2	*
1946-47	*	*	*	*	*	*	*	*	*	*	*	768.2	1540.4	*
1947-48	*	*	*	*	*	*	678.4	*	*	*	*	735.2	1726.8	*
1948-49	*	*	*	*	*	*	907.4	612.9	612.9	627.3	676.5	1061.8	*	*
1949-50	*	*	*	*	*	*	669.6	160.3	160.3	160.3	160.3	449.9	1285.2	*
1950-51	*	*	*	*	*	*	*	*	*	*	*	697.5	1307.0	*
1951-52	*	*	*	*	*	*	678.4	*	*	*	*	539.2	937.3	*
1952-53	*	*	*	*	*	*	669.6	*	*	*	*	574.0	1278.8	*
1953-54	*	*	*	*	*	*	*	*	*	*	*	580.1	1339.8	*
1954-55	*	*	*	*	*	*	*	*	*	*	*	378.0	1195.9	*
1955-56	*	*	*	*	*	*	678.4	*	*	*	207.2	652.3	1432.2	*
1956-57	*	*	*	*	*	*	669.6	*	*	*	160.3	919.9	1604.5	*
1957-58	*	*	*	*	*	*	*	*	*	*	*	879.3	1726.8	*

TABLE 10M
(Metric Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2003 - 04 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19105.3	19115.8	17805.9	15539.8	12756.1	8571.7	8649.7	8885.6	8569.2	8414.3	11013.6	16016.7	19119.2
1929-30	"	"	"	"	"	"	7028.3	6610.7	6533.4	6607.5	7511.1	11013.6	16016.7	"
1930-31	"	"	"	"	"	"	7762.1	7667.4	7436.4	7480.7	8023.6	11013.6	16016.7	"
1931-32	"	"	"	"	"	"	3373.6	2441.7	1814.6	1805.3	2882.8	8581.7	14959.7	"
1932-33	"	"	"	"	"	"	3188.7	2843.4	2705.7	2723.3	3411.8	7708.3	14093.9	"
1933-34	"	"	"	"	"	"	2648.0	1478.0	380.4	645.9	2023.8	9242.0	16016.7	"
1934-35	"	"	"	"	"	"	5140.3	4874.4	5027.8	5176.8	4980.8	7824.2	14638.0	"
1935-36	"	"	"	"	"	"	4707.5	4200.6	3926.5	3872.7	4480.2	9107.2	16016.7	"
1936-37	"	"	"	"	"	"	8571.7	8649.7	8885.6	8569.2	8414.3	11013.6	16016.7	"
1937-38	"	"	"	"	"	"	5702.5	5298.6	4954.9	5154.7	5761.3	8226.2	15043.9	"
1938-39	"	"	"	"	"	"	7282.8	6916.3	6663.8	6697.6	7055.0	10466.8	16016.7	"
1939-40	"	"	"	"	"	"	6285.3	5800.4	5738.5	6021.1	6928.8	11010.9	16016.7	"
1940-41	"	"	"	"	"	"	8207.1	8215.2	8885.6	8546.2	8381.1	11011.7	15976.5	"
1941-42	"	"	"	"	"	"	8244.8	8047.6	5577.8	5508.0	5613.5	8719.9	16016.7	"
1942-43	"	"	"	"	"	"	8571.7	8625.7	8827.1	5636.0	6143.2	7373.6	13188.2	"
1943-44	"	"	"	"	"	"	8571.7	8649.7	8885.6	8569.2	8414.3	11013.6	16016.7	"
1944-45	"	"	"	"	"	"	8571.7	8649.7	6930.0	6816.7	6910.2	9608.5	15499.5	"
1945-46	"	"	"	"	"	"	2577.7	1995.0	1797.5	1803.6	2653.1	8067.4	15301.8	"
1946-47	"	"	"	"	"	"	4101.0	3599.7	3472.2	3584.8	4530.4	9055.6	15714.5	"
1947-48	"	"	"	"	"	"	3557.6	3111.3	2955.2	2866.2	3515.8	8553.6	15254.3	"
1948-49	"	"	"	"	"	"	8571.7	8474.3	8768.9	5801.1	6275.3	10091.2	16016.7	"
1949-50	"	"	"	"	"	"	4294.5	3644.7	3472.5	3472.2	4133.5	6319.1	12439.2	"
1950-51	"	"	"	"	"	"	4779.9	4500.8	4447.4	4411.0	5321.1	7095.1	15452.0	"
1951-52	"	"	"	"	"	"	6165.4	5657.8	5495.3	5419.0	6104.5	8069.1	14330.7	"
1952-53	"	"	"	"	"	"	7838.4	7386.8	7233.1	5441.2	5683.0	7330.0	15972.1	"
1953-54	"	"	"	"	"	"	2577.7	1541.8	1397.7	1468.7	2152.5	7204.0	11487.0	"
1954-55	"	"	"	"	"	"	5236.2	4999.9	4952.7	4958.5	5343.6	7568.1	14131.8	"
1955-56	"	"	"	"	"	"	3226.1	2685.6	2518.3	2515.8	3326.9	8585.1	14603.5	"
1956-57	"	"	"	"	"	"	3844.1	3386.8	3241.3	3242.5	3916.8	8922.5	16016.7	"
1957-58	"	"	"	"	"	"	3240.0	2399.4	2390.6	2608.8	3607.3	8624.8	15729.2	"

TABLE 11M
(Metric Units)
COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	1999-00	2000-01	2001-02	2002-03	2003-04
MICA TARGET OPERATION					
(hm³ [xxxx.x] or m³/s [xxxx.xx])					
AUG 15	8455.9	8529.3	8529.3	8529.3	8561.1
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	8387.4	8284.7	8309.1	8309.1	8255.1
NOV	7770.9	7477.3	566.34	566.34	566.34
DEC	679.60	707.92	622.97	622.97	651.29
JAN	707.92	736.24	679.60	679.60	707.92
FEB	622.97	651.29	594.65	594.65	594.65
MAR	594.65	622.97	622.97	509.70	538.02
APR 15	382.2	736.2	798.1	688.2	499.4
APR 30	259.8	259.8	137.5	424.75	424.75
MAY	283.17	226.5	283.17	283.17	283.17
JUN	283.17	226.5	283.17	283.17	283.17
JUL	8455.9	8455.9	8455.9	8455.9	8438.8
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm³)					
1928 AUG 31	19119.2	19119.2	19098.6	19110.6	19105.3
1928 DEC	13746.0	13218.2	12992.4	14217.4	12756.1
1929 APR15	4313.6	3909.4	3568.9	3553.9	3910.9
1929 JUL	16920.7	17410.3	18234.5	18170.4	17813.0
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm³)					
50-yr Average for AOP00–AOP02, 60-yr average for AOP03 & AOP04					
AUG 31	17848.9	18079.9	18134.9	18140.6	18141.5
DEC	12925.6	12619.1	12812.6	12788.1	11644.6
APR15	3484.0	2815.3	2777.6	2870.1	2685.6
JUL	17369.1	17795.8	18002.6	17955.6	17767.2
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-1.5	-0.3	0.2	-0.3	-1.2
U.S. Dependable Peaking Capacity	0.0	-2.0	0.0	-18.0	16.0
U.S. Average Annual Usable Secondary Energy	19.5	16.2	24.9	3.7	12.9
BCH Firm Energy	102.2	60.8	48.3	30.3	43.1
BCH Dependable Peaking Capacity	-3.0	-36.0	25.0	26.0	8.0
BCH Average Annual Usable Secondary Energy	-42.9	-43.6	-29.7	-17.3	-24.3
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	9254	9499	9886	10368	10439
AUG 31	9460	9650	9975	10355	10435
SEP	9063	9519	9872	9911	10101
OCT	8789	9079	9426	10051	10186
NOV	10317	10417	10665	11716	11807
DEC	11801	11762	11936	13160	13377
JAN	12643	12269	12171	13707	13122
FEB	11944	12075	11844	12694	12240
MAR	11301	11034	10958	11858	11175
APR 15	10519	10571	10315	11460	10541
APR 30	12024	12297	11729	13101	13065
MAY	16583	13691	13988	14357	13752
JUN	13387	10841	11552	13324	13114
JUL	9017	10686	9860	10457	12079
ANNUAL AVERAGE	12131	11850	11919	11986	11933

Appendix A1
(English Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Canadian Projects					
Mica (1890)	Minimum Flow	3000 cfs			In place in AOP79, AOP80, AOP84
Arrow (1831)	Minimum Flow	5000 cfs			In place in AOP79, AOP80, AOP84
	Draft Limit		1 ft/day		
Duncan (1681)	Minimum Flow	100 cfs			In place in AOP79, AOP80, AOP84
	Maximum Flow	10000 cfs			In place in AOP79, AOP80, AOP84
	Draft Limit		1 ft/day		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order
Base System					
Hungry Horse (1530)	Minimum Flow	400 cfs		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		All periods	In place in AOP80, AOP84
	Maximum Flow			None	
	Minimum Content	614.7 ksfd 426.3 ksfd	2893.0 ft 2890.0 ft	Jun - Sep May	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80
		0.0 ksfd	2883.0 ft	Empty Apr 15	FERC, AOP80
	Maximum Content	58.6 ksfd	2884.0 ft	March (Included to help meet the Apr 15 FERC requirement.)	In place in AOP80, AOP84
	Other	0.0 ksfd	2883.0 ft	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80
Thompson Falls (1490)				None Noted	
Noxon Rapids (1480)	Minimum Content For Step I:	116.3 ksfd 112.3 ksfd 78.7 ksfd 26.5 ksfd 0.0 ksfd	2331.0 ft 2330.0 ft 2321.0 ft 2305.0 ft 2295.0 ft	May - Aug 31, Sep - Jan, Feb, Mar, Empty Apr 15, Apr 30, and for end of CP	In place in AOP84, similar operation in AOP80
	Minimum & Maximum Content For Steps II & III:	116.3 ksfd	2331.0 ft	All periods	In place in AOP79, AOP84

Appendix A1
(English Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	4000 cfs		All periods	In place in AOP80, AOP84
	Minimum Content	(Dec may fill on restriction, note below)			
		582.4 ksfd	2062.5 ft	Jun - Aug 31	In place in AOP80, AOP84
		465.7 ksfd	2060.0 ft	Sep	
		190.4 ksfd	2054.0 ft	Oct	
		57.6 ksfd	2051.0 ft	Nov-Apr 15	
		190.4 ksfd	2054.0 ft	Apr 30 (empty at end of CP)	
		279.0 ksfd	2056.0 ft	May	
	For Steps I & II:	Optimum to run CP & LT to Jun-Oct SMINs.			
	For Step III:	Keep full at beginning of CP. Optimum to run higher than SMIN in CP & LT (except when occasionally drafting below SMIN to meet load).			
		57.6 ksfd	2051.0 ft	Nov - Mar	
		458.4 ksfd	2059.8 ft	May	
		582.4 ksfd	2062.5 ft	Sep	
		465.7 ksfd	2060.0 ft	Oct	
	Kokanee Spawning	Draft no more than 1 ft below Nov 20 elevation through Dec 31. If project fills, draft no more than 0.5 ft. Dec 31 - Mar 31 operate between SMIN and URC within above noted draft limits.			In place before AOP80 and supported by minimum contents noted above.
	Other Spill	50 cfs		All periods	
Box Canyon (1460)				None Noted	
Grand Coulee (1280)	Minimum Flow	30000 cfs		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content				
		0.0 ksfd	1208.0 ft	Empty at end of CP	
	Step I only:	843.9 ksfd	1240.0 ft	May and June	Retain as a power operation (for pumping)
	Steps II & III only:	857.9 ksfd	1240.0 ft	May and June	
	Maximum Content				
	Step I only:		2 ft	Operating room Sep - Nov	In place in AOP89. Retain as a power operation
			3 ft	Operating room Dec - Feb	
	Steps II & III only:	2557.1 ksfd	1288.0 ft	Aug-Nov	
		2518.3 ksfd	1287.0 ft	Dec-Feb	
	Draft Limit		1.3 ft/day	(bank sloughage)	
			1.5 ft/day	(Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo.ave.)	
Chief Joseph (1270)	Other Spill	500 cfs		All periods	
Wells (1220)	Other Spill	1200 cfs		All periods	With fish ladder
	Fish Spill			Removed	
Rocky Reach (1200)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	200 cfs		Aug 31 - Apr 15 (leakage)	
	Fish Spill			Removed	

Appendix A1
(English Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Rock Island (1170)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Fish Spill			Removed	
Wanapum (1165)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	2200 cfs		All periods	With fish ladder
	Fish Spill			Removed	
Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	2200 cfs		All periods	With fish ladder
	Fish Spill			Removed	
Brownlee (767)	Minimum Flow	5000 cfs		All periods	In place in AOP79, AOP80, AOP84
	Power Operation			Agree to use "old" power operation (first codes) provided by IPC and used in AOP since AOP97. More recent information for BRN from IPC operates the project variably (depending on inflow estimates) and for flow augmentation and water temperature control (S. Davis communication with IPC, 1992 and 1994).	2-1-91 PNCA submittal
Oxbow (765)	Other Spill	100 cfs		All periods	
Ice Harbor (502)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	740 cfs		All periods	
	Incremental Spill			None	
	Fish Spill			None	
	Minimum Flow			None	
	Other	204.8 ksfd	440.0 ft	Run at all periods	
McNary (488)	Other Spill	3475 cfs		All periods	
	Incremental Spill			None	

Appendix A1
(English Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
John Day (440)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	800 cfs		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	50000 cfs 12500 cfs		Mar - Nov Dec - Feb	
	Other Step I:	269.7 ksfd 242.5 ksfd 153.7 ksfd 114.9 ksfd	268.0 ft 267.0 ft 263.6 ft 262.0 ft	June - Aug 15 Aug 31 - Sep Oct - Mar Apr 15 - May	In place AOP80
	Steps II & III:	190.0 ksfd	265.0 ft	Use JDA as run-of-river plant.	
The Dalles (365)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	1300 cfs		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	50000 cfs 12500 cfs		Mar - Nov Dec - Feb	
Bonneville (320)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	8040 cfs		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
Kootenay Lake (Corra Linn (1665))	Minimum Flow	5000 cfs		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		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	308.5 ksfd	1098.0 ft	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
Couer d'Alene L (1341)	Minimum Flow	50 cfs		All periods	
	Minimum Content	112.5 ksfd	2128.0 ft	May - Aug	In place in AOP79
Post Falls (1340)	Minimum Flow	50 cfs		All periods	In place in AOP79, AOP80, AOP84

Appendix A1
(English Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Other Major Step I Projects					
Libby (1760) without sturgeon					
	Minimum Flow	4000 cfs		All periods	
	Other Spill	200 cfs		All periods	
	Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
		776.9 ksfd	2363.0 ft	1929 Dec	2-1-93 PNCA submittal, in place in AOP99 (w/o sturgeon)
		676.5 ksfd	2355.0 ft	1929 Jan	
		603.6 ksfd	2349.0 ft	1929 Feb	
		2147.7 ksfd	2443.0 ft	1929 Jul	
		652.0 ksfd	2353.0 ft	1930 Dec	
		433.2 ksfd	2334.0 ft	1930 Jan	
		389.3 ksfd	2330.0 ft	1930 Feb	
		348.5 ksfd	2326.0 ft	1930 Mar	
		297.4 ksfd	2321.0 ft	1930 Apr 15	
		444.2 ksfd	2335.0 ft	1930 Apr 30	
		499.1 ksfd	2340.0 ft	1930 May	
		1344.6 ksfd	2402.0 ft	1930 Jun	
		1771.9 ksfd	2425.0 ft	1930 Jul	
		317.8 ksfd	2323.0 ft	1931 Dec	
		192.2 ksfd	2310.0 ft	1931 Jan	
		103.1 ksfd	2300.0 ft	1931 Feb-Apr 30	
		192.2 ksfd	2310.0 ft	1931 May	
		676.5 ksfd	2355.0 ft	1931 Jun	
		868.0 ksfd	2370.0 ft	1931 Jul	
		174.4 ksfd	2308.0 ft	1932 Dec	
		103.1 ksfd	2300.0 ft	1932 Jan	
		0.0 ksfd	2287.0 ft	Empty at end of CP***	
		776.9 ksfd	2363.0 ft	All Dec	
		July 1930 - No more than 373.1 ksfd lower than July 1929 July 1931 - No more than 857.1 ksfd lower than July 1930 March - Implement PNCA 6(c)2(c).			2-1-94 PNCA submittal, in place in AOP00 and AOP01 (w/o sturgeon)
	Maximum Summer		5 ft		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order

Appendix A1
(English Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Dworshak (535)	Minimum Flow	1300 cfs		All periods	2-1-97 PNCA submittal
	Maximum Flow	14000 cfs		Apr 30 - Aug31 (model requirement includes 14000 cfs for all period but URC generally overrides.)	2-1-97 PNCA submittal
		25000 cfs		Up to 25 kcfs for flood control all periods.	
	Minimum Elev	395.8 ksfd	1520.0 ft	SMIN Apr 15 - Aug 31	
	Start 3 yr CP at:	395.8 ksfd	1520.0 ft	Aug 15 (0.1 ft) higher than AOP03	
	End 3 yr CP at:	218.4 ksfd	1490.2 ft	Feb Same as AOP03	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements all periods except to meet LWG outflows:			2-1-97 PNCA submittal
	LWG Target Flow	36000 cfs 85000 cfs to 50000 cfs to	(≥) 100000 cfs 55000 cfs	Apr 15 [(10x11500)+(5x85000)/15] Apr 30 - Jun 20, and Jun 21 - Aug 31.	
	Other Spill	100 cfs		All periods	
Lower Granite (520)	Bypass Date			None	
	Other Spill	670 cfs		All periods	
	Incremental Spill			Removed	
	Fish Spill	(LT only if regulated flow ≥ 100000 cfs)	16.0% 40.0% 26.7%	Apr 15 Apr 30 & May Jun	2-1-97 PNCA submittal
		(CP only if regulated flow ≥100000 cfs)	20.1% 39.7% 27.0% 24.0%	Apr 15 Apr 30 May Jun	
	Maximum Fish Spill	22500 cfs			
	Minimum Flow	11500 cfs		Mar-Nov	
	Other	224.9 ksfd 245.8 ksfd	733 ft 738 ft	Run at (MOP) Apr 15 - Oct. Run at all other periods.	

Appendix A1
(English Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Little Goose (518)	Bypass Date			None	
	Other Spill	630 cfs		All periods	
	Incremental Spill			Removed	
	Fish Spill	(LT only if regulated flow at Lower Granite ≥ 85000 cfs)			2-1-97 PNCA submittal
			16.0%	Apr 15	
			40.0%	Apr 30 & May	
			26.7%	Jun	
		(CP only if regulated flow at Lower Granite ≥ 85000 cfs)			
			20.2%	Apr 15	
			40.3%	Apr 30	
			29.9%	May	
			26.4%	Jun	
	Maximum Fish Spill	30000 cfs			
	Minimum Flow	11500 cfs		Mar - Nov	
	Other	260.5 ksfd	633.0 ft	On MOP Apr 15 - Aug 31.	
		285.0 ksfd	638.0 ft	On full pool Sep 30 - Mar 31.	
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	750 cfs		All periods	
	Fish Spill	(LT only if regulated flow at Lower Granite ≥ 85000 cfs)			2-1-97 PNCA submittal
			16.2%	Apr 15	
			40.5%	Apr 30 & May	
			27.0%	Jun	
		(CP only if regulated flow at Lower Granite ≥ 85000 cfs)			
			20.5%	Apr 15	
			36.2%	Apr 30	
			24.0%	May	
			21.1%	Jun	
	Maximum Fish Spill	20000 cfs			
	Minimum Flow	11500 cfs		Mar-Nov	
	Other	180.5 ksfd	537.0 ft	On MOP Apr 15 - Aug 31.	
		190.1 ksfd	540.0 ft	On full pool Sep 30 - Mar 31.	
Cushman (2206)	Other Spill	100 cfs		All periods	
LaGrande (2188)	Other Spill	30 cfs		All periods	
White River (2160)	Other Spill	130 cfs		All periods	
Round Butte (390)	Other Spill	200 cfs		All periods	

Appendix A2
(Metric Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Canadian Projects					
Mica (1890)	Minimum Flow	84.95 m^3/s			In place in AOP79, AOP80, AOP84
Arrow (1831)	Minimum Flow	141.58 m^3/s			In place in AOP79, AOP80, AOP84
	Draft Limit		0.30 m/day		
Duncan (1681)	Minimum Flow	2.83 m^3/s			In place in AOP79, AOP80, AOP84
	Maximum Flow	283.17 m^3/s			In place in AOP79, AOP80, AOP84
	Draft Limit		0.30 m/day		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order
Base System					
Hungry Horse (1530)	Minimum Flow	11.33 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	42.48 m^3/s		All periods	In place in AOP80, AOP84
	Maximum Flow			None	
	Minimum Content	1503.9 hm^3 1043.0 hm^3	881.79 m 880.87 m	Jun - Sep May	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80
		0.0 hm^3	878.74 m	Empty Apr 15	FERC, AOP80
	Maximum Content	143.4 hm^3	879.04 m	March (Included to help meet the Apr 15 FERC requirement.)	In place in AOP80, AOP84
	Other	0.0 hm^3	878.74 m	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80
Thompson Falls (1490)				None Noted	

Appendix A2
(Metric Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Noxon Rapids (1480)	Minimum Content For Step I:	284.5 hm^3	710.49 m	May - Aug 31,	In place in AOP84, similar operation in AOP80
		274.8 hm^3	710.18 m	Sep - Jan,	
		192.5 hm^3	707.44 m	Feb,	
		64.8 hm^3	702.56 m	Mar,	
		0.0 hm^3	699.52 m	Empty Apr 15, Apr 30, and for end of CP	
	Minimum & Maximum Content For Steps II & III:	284.5 hm^3	710.49 m	All periods	In place in AOP79, AOP84
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	113.27 m^3/s		All periods	In place in AOP80, AOP84
	Minimum Content	(Dec may fill on restriction, note below)			
		1424.9 hm^3	628.65 m	Jun - Aug 31	In place in AOP80, AOP84
		1139.4 hm^3	627.89 m	Sep	
		465.8 hm^3	626.06 m	Oct	
		140.9 hm^3	625.14 m	Nov-Apr 15	
		465.8 hm^3	626.06 m	Apr 30 (empty at end of CP)	
		682.6 hm^3	626.67 m	May	
	For Steps I & II:	Optimum to run CP & LT to Jun-Oct SMINs.			
	For Step III:	Keep full at beginning of CP. Optimum to run higher than SMIN in CP & LT (except when occasionally drafting below SMIN to meet load).			
		140.9 hm^3	625.14 m	Nov - Mar	
		1121.5 hm^3	627.83 m	May	
		1424.9 hm^3	628.65 m	Sep	
		1139.4 hm^3	627.89 m	Oct	
	Kokanee Spawning	Draft no more than 0.30 m below Nov 20 elevation through Dec 31. If project fills, draft no more than 0.15 m. Dec 31 - Mar 31 operate between SMIN and URC within above noted draft limits.			In place before AOP80 and supported by minimum contents noted above.
	Other Spill	1.42 m^3/s		All periods	
Box Canyon (1460)				None Noted	
Grand Coulee (1280)	Minimum Flow	849.50 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	0.00 m^3/s	368.20 m	Empty at end of CP	
	Step I only:	2064.7 hm^3	377.95 m	May and June	Retain as a power operation (for pumping)
	Steps II & III only:	2098.9 hm^3	377.95 m	May and June	
	Maximum Content Step I only:		0.61 m	Operating room Sep - Nov	In place in AOP89. Retain as a power operation
			0.91 m	Operating room Dec - Feb	
	Steps II & III only:	6256.2 hm^3	392.58 m	Aug-Nov	
		6161.3 hm^3	392.28 m	Dec-Feb	
	Draft Limit		0.40 m/day	(bank sloughage)	
			0.46 m/day	(Constraint submitted as 0.46 m/day interpreted as 0.40 m/day mo. ave.)	
Chief Joseph (1270)	Other Spill	14.16 m^3/s		All periods	

Appendix A2
(Metric Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Wells (1220)	Other Spill	33.98 m^3/s		All periods	With fish ladder
	Fish Spill			Removed	
Rocky Reach (1200)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	5.66 m^3/s		Aug 31 - Apr 15 (leakage)	
	Fish Spill			Removed	
Rock Island (1170)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Fish Spill			Removed	
Wanapum (1165)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	62.30 m^3/s		All periods	With fish ladder
	Fish Spill			Removed	
Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	62.30 m^3/s		All periods	With fish ladder
	Fish Spill			Removed	
Brownlee (767)	Minimum Flow	141.58 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Power Operation			Agree to use "old" power operation (first codes) provided by IPC and used in AOP since AOP97. More recent information for BRN from IPC operates the project variably (depending on inflow estimates) and for flow augmentation and water temperature control (S. Davis communication with IPC, 1992 and 1994).	2-1-91 PNCA submittal
Oxbow (765)	Other Spill	2.83 m^3/s		All periods	
Ice Harbor (502)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	20.95 m^3/s		All periods	
	Incremental Spill			None	
	Fish Spill			None	
	Minimum Flow			None	
	Other	501.1 hm^3	134.11 m	Run at all periods	
McNary (488)	Other Spill	98.40 m^3/s		All periods	
	Incremental Spill			None	

Appendix A2
(Metric Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
John Day (440)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	22.65 m^3/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	1415.84 m^3/s 353.96 m^3/s		Mar - Nov Dec - Feb	
	Other Step I:	659.8 hm^3 593.3 hm^3 376.0 hm^3 281.1 hm^3	81.69 m 81.38 m 80.35 m 79.86 m	June - Aug 15 Aug 31 - Sep Oct - Mar Apr 15 - May	In place AOP80
	Steps II & III:	464.9 hm^3	80.77 m	Use JDA as run-of-river plant.	
The Dalles (365)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	36.81 m^3/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	1415.84 m^3/s 353.96 m^3/s		Mar - Nov Dec - Feb	
Bonneville (320)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	227.67 m^3/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
Kootenay Lake (Corra Linn (1665))	Minimum Flow	141.58 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	1.42 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	754.8 hm^3	334.67 m	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
Couer d'Alene L (1341)	Minimum Flow	1.42 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	275.2 hm^3	648.61 m	May - Aug	In place in AOP79
Post Falls (1340)	Minimum Flow	1.42 m^3/s		All periods	In place in AOP79, AOP80, AOP84

Appendix A2
(Metric Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Other Major Step I Projects					
Libby (1760) without sturgeon					
	Minimum Flow	113.27 m^3/s		All periods	
	Other Spill	5.66 m^3/s		All periods	
	Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
		1900.8 hm^3	720.24 m	1929 Dec	2-1-93 PNCA submittal, in place in AOP99 (w/o sturgeon)
		1655.1 hm^3	717.80 m	1929 Jan	
		1476.8 hm^3	715.98 m	1929 Feb	
		5254.6 hm^3	744.63 m	1929 Jul	
		1595.2 hm^3	717.19 m	1930 Dec	
		1059.9 hm^3	711.40 m	1930 Jan	
		952.5 hm^3	710.18 m	1930 Feb	
		852.6 hm^3	708.96 m	1930 Mar	
		727.6 hm^3	707.44 m	1930 Apr 15	
		1086.8 hm^3	711.71 m	1930 Apr 30	
		1221.1 hm^3	713.23 m	1930 May	
		3289.7 hm^3	732.13 m	1930 Jun	
		4335.1 hm^3	739.14 m	1930 Jul	
		777.5 hm^3	708.05 m	1931 Dec	
		470.2 hm^3	704.09 m	1931 Jan	
		252.2 hm^3	701.04 m	1931 Feb-Apr 30	
		470.2 hm^3	704.09 m	1931 May	
		1655.1 hm^3	717.80 m	1931 Jun	
		2123.6 hm^3	722.38 m	1931 Jul	
		426.7 hm^3	703.48 m	1932 Dec	
		252.2 hm^3	701.04 m	1932 Jan	
		0.0 hm^3	697.08 m	Empty at end of CP***	
		1900.8 hm^3	720.24 m	All Dec	
		July 1930 - No more than 912.8 hm^3 lower than July 1929 July 1931 - No more than 2097.0 hm^3 lower than July 1930 March - Implement PNCA 6(c)2(c).			2-1-94 PNCA submittal, in place in AOP00 and AOP01 (w/o sturgeon)
	Maximum Summer		1.52 m		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order

Appendix A2
(Metric Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Dworshak (535)	Minimum Flow	36.81 m^3/s		All periods	2-1-97 PNCA submittal
	Maximum Flow	396.44 m^3/s		Apr 30 - Aug31 (model requirement includes 396.44 m^3/s for all period but URC generally	2-1-97 PNCA submittal
		707.92 m^3/s		Up to 707.92 m^3/s for flood control all periods.	
	Minimum Elev	968.4 hm^3	463.30 m	SMIN Apr 15 - Aug 31	
	Start 3 yr CP at: End 3 yr CP at:	968.4 hm^3 534.3 hm^3	463.30 m 454.21 m	Aug 15 (0.03 m) higher than AOP03 Feb Same as AOP03.	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements all periods except to meet LWG outflows:			2-1-97 PNCA submittal
	LWG Target Flow	1019.41 m^3/s 2406.93 m^3/s to 1415.84 m^3/s to	($\geq$) 2831.68 m^3/s 1557.43 m^3/s	Apr 15 [(10x325.64)+(5x2406.93)/15] Apr 30 - Jun 20, and Jun 21 - Aug 31.	
	Other Spill	2.83 m^3/s		All periods	
Lower Granite (520)	Bypass Date			None	
	Other Spill	18.97 m^3/s		All periods	
	Incremental Spill			Removed	
	Fish Spill	(LT only if regulated flow $\geq$ 2831.66 m^3/s)	16.0% 40.0% 26.7%	Apr 15 Apr 30 & May Jun	2-1-97 PNCA submittal
		(CP only if regulated flow $\geq$ 2831.66 m^3/s)	20.1% 39.7% 27.0% 24.0%	Apr 15 Apr 30 May Jun	
	Maximum Fish Spill	637.13 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar-Nov	
	Other	550.2 hm^3 601.4 hm^3	223.42 m 224.94 m	Run at (MOP) Apr 15 - Oct. Run at all other periods.	

Appendix A2
(Metric Units)
Project Operating Procedures
2003-04 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Little Goose (518)	Bypass Date			None	
	Other Spill	17.84 m^3/s		All periods	
	Incremental Spill			Removed	
	Fish Spill	(LT only if regulated flow at Lower Granite $\geq$ 2406.93 m^3/s)			2-1-97 PNCA submittal
			16.0%	Apr 15	
			40.0%	Apr 30 & May	
			26.7%	Jun	
		(CP only if regulated flow at Lower Granite $\geq$ 2406.93 m^3/s)			
			20.2%	Apr 15	
			40.3%	Apr 30	
			29.9%	May	
			26.4%	Jun	
	Maximum Fish Spill	849.50 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar - Nov	
	Other	637.3 hm^3	192.94 m	On MOP Apr 15 - Aug 31.	
		697.3 hm^3	194.46 m	On full pool Sep 30 - Mar 31.	
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	21.24 m^3/s		All periods	
	Fish Spill	(LT only if regulated flow at Lower Granite $\geq$ 2406.93 m^3/s)			2-1-97 PNCA submittal
			16.2%	Apr 15	
			40.5%	Apr 30 & May	
			27.0%	Jun	
		(CP only if regulated flow at Lower Granite $\geq$ 2406.93 m^3/s)			
			20.5%	Apr 15	
			36.2%	Apr 30	
			24.0%	May	
			21.1%	Jun	
	Maximum Fish Spill	566.34 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar-Nov	
	Other	441.6 hm^3	163.68 m	On MOP Apr 15 - Aug 31.	
		465.1 hm^3	164.59 m	On full pool Sep 30 - Mar 31.	
Cushman (2206)	Other Spill	2.83 m^3/s		All periods	
LaGrande (2188)	Other Spill	0.85 m^3/s		All periods	
White River (2160)	Other Spill	3.68 m^3/s		All periods	
Round Butte (390)	Other Spill	5.66 m^3/s		All periods	

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2003-04

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2003-04

January 2000

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) 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 downstream power benefit computations developed from the 2003-04 Assured Operating Plan (AOP).

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; and in the following 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/DDPB's, and Operating Procedures for the 2001-02 and Future AOP's," signed 29 August 1996;
- The "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated December 1991; and
- The Entity Agreements, signed 28 July and 12 August 1988, on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies (1988 Entity Agreements).

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

Step I -- Operation of the total United States of America planned hydro and thermal system, with 15.5 million acre-feet (Maf) (19.12 cubic kilometers (km^3)) of Canadian storage operated for flood control and optimum power generation in both countries.

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

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

As part of the DDPB for the operating year 2003-04, separate determinations were carried out relating to the limit of year-to-year change in benefits attributable to the

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

operation of Canadian Treaty storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America (Joint Optimum).

2. Results of Canadian Entitlement Computations

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

Dependable Capacity	=	1176.4 MW
Average Annual Usable Energy	=	537.3 aMW

All downstream power benefits computations are rounded to the nearest tenth of a megawatt.

3. Computation of Maximum Allowable Reduction in Downstream Power Benefits

In accordance with the Treaty Annex A, paragraph 7 and Part III, paragraph 15c(2) of POP, the computation of the maximum allowable reduction in downstream power benefits and the resulting minimum permitted Canadian Entitlement to downstream power benefits for the 2003-04 operating year are based on the formula: Minimum Canadian Entitlement = X - (Y - Z). The quantities X, Y, and Z, expressed in terms of entitlement to downstream power benefits, are computed as follows:

X = One-half of the downstream power benefits derived from the difference between the 2002-03 Step II Joint Optimum study and the 2002-03 Step III study.

Y = One-half of the downstream power benefits derived from the difference between the 2002-03 Step II U.S. Optimum study and the 2002-03 Step III study.

Z = One-half of the downstream power benefits derived from the difference between the 2003-04 Step II U.S. Optimum study with 15 Maf (18.50 km^3) of Canadian storage and the 2003-04 Step III study.

The purpose of this formula is to set a lower limit on the Canadian Entitlement for the re-operation of Canadian storage. This minimum is based on the previous operating year Canadian Entitlement, plus the effect of removing 0.5 Maf (0.62 km^3) of Canadian storage, and taking out the effect due to changes in loads, resources, and other operating procedures.

The quantities X and Y were computed in the 2002-03 DDPB Table 5. The quantity Z is computed in Table 5 of this report. The computation of the Minimum Canadian Entitlement is as follows:

Dependable Capacity	= 1170.7 - (1171.4 – 1151.6)	= 1150.9 MW
Average Annual Usable Energy	= 534.5 - (532.8 – 526.6)	= 528.3 aMW

The computed Canadian Entitlement exceeds these amounts.

4. Effect on Sale of Canadian Entitlement

Since the sale of the downstream power benefits under the Canadian Entitlement Purchase Agreement (CEPA) expires 31 March 2003, the United States Entity is not entitled to compensation during the 2003-04 operating year for any decrease in the Canadian Entitlement that may exist from the difference between studies for optimum power generation only in the United States of America (U.S. Optimum) and studies for optimum power generation at-site in Canada and downstream in Canada and the United States of America (Joint Optimum).

5. Delivery of the Canadian Entitlement

See Section 7 of the 2003-04 AOP.

6. 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 model 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 for the downstream power benefit determination of average annual usable energy. The thermal displacement market 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 Step 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 unpublished BPA 1997 Whitebook load forecast. The Grand Coulee pumping load is included in this estimate. The method for computing the firm load for the Step II and III studies is described in the 1988 Entity Agreements and in POP.

Table 4 Summary of Power Regulations From 2003-04 Assured Operating Plan:

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system. The determination of the Step I, II, and III loads and thermal installations is shown in Tables 1 and 3. The hydro maintenance is summed with the reserves in the Step I system load as an adjustment to resources.

Table 5 Computation of Canadian Entitlement For 2003-04 Assured Operating Plan:

A. Joint Optimum Generation in Canada and the U.S.
B. Optimum Generation in the U.S. Only
C. Optimum Generation in the U.S. and a 0.5 Million Acre-Feet (0.62 km^3) Reduction in Total Canadian Treaty Storage

The essential elements used in the computation of the Canadian Entitlement to downstream power benefits and the computation of maximum allowable reduction in downstream power benefits only are shown on this table.

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 from the Step II and III studies, which graphically illustrates the change in average annual usable energy. Usable energy is firm energy plus usable secondary energy. Secondary energy is the energy capability each month that exceeds the firm hydro loads shown in Table 3. The usable secondary energy in average megawatts for the Step II and III studies is computed in accordance with Annex B, paragraphs 3(b) and 3(c), as the portion of secondary energy which can displace thermal resources that were used to meet PNWA loads plus the other usable secondary generation. The Entities have agreed that the other usable secondary is computed on the basis of 40 percent of the secondary energy remaining after thermal displacement.

7. Summary of Changes from Previous Year

Data from the five most recent DDPB's are summarized in Table 6. An explanation of the more important changes which impact computation of the entitlement compared to last year's studies follows.

(a) Loads and Non-Hydro Resources

Loads for the 2003-04 AOP were based on the unpublished 1997 Whitebook medium case forecast developed by BPA on 31 December 1996 for the 1999 through 2008 operating years. This forecast was also used in the 2002-03 AOP. The PNWA firm energy load increased by 103 aMW compared to the 2002-03 AOP. Other load changes include:

- Since the sale of the Entitlement attributable to Mica terminates on 31 March 2003, all of the Canadian Entitlement will belong to Canada during the 2003-04 operating year. It was assumed that one-half of the Canadian Entitlement was exported to B.C. and the remaining one-half was disposed in the U.S. This resulted in an increase of 35 aMW in the Canadian Entitlement exports (B.C. + S.W.) compared to the 2002-03 AOP study, which modeled one-half of the Entitlement exported to Canada, one-eighth exported to the Southwest, and three-eighths of the Entitlement used to meet load in the PNWA.

  The estimated disposition of the Entitlement in the Step I system and the computed Canadian Entitlement are shown below:

  During 1 August 2003 – 31 July 2004

Entitlement	Energy (aMW)		Capacity (MW)	
	Estimated	Computed	Estimated	Computed
Export to BC	267.25	268.65	585.35	588.2
Retained in PNW	267.25	268.65	585.35	588.2
Total	534.5	537.3	1170.7	1176.4

  Iterative studies to correct the load estimate were not performed because updating the Canadian Entitlement Return estimates would not significantly affect the results of the studies.

- A seasonal exchange import of 950 MW each period was added in January through 15 April to balance the seasonal exchange export of 1095 MW added in May through July. This created an annual average surplus in the spring similar to that of the previous year's study. An additional 396 MW of firm surplus was shaped May through July. The average annual firm surplus increased by 51 aMW compared to the 2002-03 AOP study.

The total annual energy capability of the thermal installations decreased by 19 aMW due to the following changes:

- Large Thermal resources decreased by 22 aMW due to data updates for Colstrip 1-4;

- Cogeneration increased by 19 aMW mostly due to increased generation at Encogen; and

- Thermal PURPA/NUGS decreased by 20 aMW because of decreased generation in NUGS from Puget and WWP.

Thermal displacement market increased by 208 aMW largely due to decreased system sales.

(b) Operating Procedures

Generation plant data tables for Arrow, Grand Coulee, McNary, Bonneville, and Chief Joseph were updated. Grand Coulee showed increased critical period generation, while McNary, Bonneville, and Chief Joseph had significant decreased critical period generation. Mica full storage content decreased by 262.8 ksfd (643.0 hm^3), or 0.521 Maf (0.64 km^3), to show B.C. Hydro Refill Storage on top of Treaty storage, as shown below;

Mica Storage & Elevation

AOP Study	Full Storage (Ksfd)	Full Storage Metric (hm^3)	Full Elev (ft)	Full Elev Metric (m)
2002-03	6087.9	14894.7	2475.00	754.38
2003-04	5825.1	14251.7	2470.07	742.88

Generation reductions of approximately 0.2% for step-up transformer losses were included for the first time at all U.S. federal projects.

The established operating procedures for Base system projects were agreed to by an Entity Agreement signed on 29 August 1996. These requirements are essentially the nonpower requirements included in the 1979-80 and prior AOP/DDPB studies. Changes from the previous studies include:

- Kerr modeling technique was included in all studies (Steps I, II, & III). This operation was consistent with the 1979-80 operation of Kerr and enabled Kerr to meet the Federal Energy Regulatory Commission (FERC) license flood control requirement in April 15 more often. (58.6 ksfd (143.4 hm^3) was added as a maximum storage limit in March for all years outside of the critical period.)
- Arrow generation was included with a maximum capability of 160.8 MW.

(c) Step III Critical Streamflow Period

As in 2002-2003, the Step III study critical streamflow period was a 6-month critical period, 1 November 1936 through 30 April 1937.

(d) Downstream Power Benefits Computation

The Capacity Entitlement increased from 1170.7 MW in the 2002-03 DDPB to 1176.4 MW in the 2003-04 DDPB for a gain of 5.7 MW because the average critical period load factor decreased by 1.5 percent due to increased peak load.

The Canadian Energy Entitlement increased from 534.5 aMW in the 2002-03 DDPB to 537.3 aMW in the 2003-04 DDPB, mostly due to higher December VECC's at Hungry Horse in the Step III studies. This caused more spill in the Step III studies which caused the Step III useable energy to decrease more than the Step II useable energy.

TABLE 1A
2003-04 ASSURED OPERATING PLAN
DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES (aMW) 1/

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July	Annual Average	CP Ave 2/ (42.5 Mon)
1. **Pacific Northwest Area (PNWA) Load 3/**	20556	20478	20042	20695	22616	24195	24832	23818	22449	21250	21339	20726	20581	20743	21872.9	21967.8
a) Annual Load Shape in Percent	93.98	93.62	91.63	94.61	103.40	110.62	113.53	108.89	102.63	97.15	97.56	94.76	94.09	94.83	100.0	100.4
2. **Flows-Out of firm power from PNWA**																
a) Canadian Entitlement Export (south+north) 4/	267	267	267	267	267	267	267	267	267	267	267	267	267	267	267.2	267.2
b) Exports to the East	155	155	141	119	141	141	142	120	115	118	118	104	159	163	134.8	135.0
c) SW Seasonal Exchange Exports	191	191	225	15	0	0	0	0	0	0	0	26	158	162	64.8	63.0
d) Other SW Exports	797	797	784	736	713	722	703	688	610	586	622	637	770	812	714.8	717.3
e) Plant Sale Exports	142	142	142	142	142	142	142	142	142	142	137	124	142	142	140.4	140.7
f) Surplus Firm Energy Exports	0	0	0	0	0	0	0	0	0	0	0	1491	1491	1491	374.7	318.2
g) Thermal Install. power used outside region 5/	380	431	463	132	156	99	101	117	285	192	195	386	643	309	274.3	262.9
h) ... Subtotal	1933	1984	2022	1412	1420	1371	1355	1335	1419	1306	1339	3035	3629	3347	1971.0	1904.2
i) Exclude Plant Sales	-142	-142	-142	-142	-142	-142	-142	-142	-142	-142	-137	-124	-142	-142	-140.4	-140.7
j) ... Total	1791	1842	1880	1270	1278	1229	1213	1193	1277	1164	1202	2911	3487	3205	1830.6	1763.5
3. **Load served by Flows-In of firm power except Step I thermal installations**																
a) Non-thermal firm imports from north 6/	-20	-20	-15	-21	-36	-47	-60	-69	-61	-29	-29	-28	-38	-26	-37.4	-37.6
b) Flows-in from SW seasonal exchanges	0	0	-1	-1	-186	-209	-1129	-1137	-989	-965	-6	0	0	0	-342.4	-350.1
c) Non-Coord. Thermal Resc from SW (not TI) 7/	-16	-16	-19	-31	-26	-26	-26	-26	-18	-16	-4	0	0	-16	-17.9	-19.0
d) ... Total	-36	-36	-35	-52	-248	-282	-1216	-1232	-1068	-1010	-39	-28	-38	-42	-397.7	-406.7
4. **Load served by non-Step I resources located within the PNWA**																
a) Hydro Independents (1929 water)	-1282	-1255	-1175	-1201	-1231	-1159	-1102	-924	-1045	-1281	-1327	-1772	-1727	-1426	-1278.8	-1143.9
b) Non-Step I Coordinated Hydro (1929 water)	-511	-439	-557	-943	-938	-1076	-951	-611	-696	-763	-791	-758	-1339	-646	-814.1	-842.7
c) Non-Thermal PURPA/NUGS	-112	-112	-103	-92	-98	-97	-97	-102	-107	-120	-120	-130	-131	-120	-109.1	-107.5
d) Miscellaneous Resources	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19.3	-19.3
e) ... Total (1929 water)	-1924	-1825	-1854	-2255	-2287	-2351	-2169	-1656	-1868	-2185	-2258	-2680	-3216	-2212	-2221.3	-2113.4
5. **Total Step I System Firm Loads (1929 water) 8/**	20387	20459	20033	19656	21358	22791	22660	22121	20790	19219	20244	20929	20814	21694	21084.5	21211.3
6. **Step I Thermal Installations**																
a) Large Thermal (includes plant sales)	4875	4875	4875	4875	4875	4875	4875	4875	4688	4640	3587	3275	3899	4875	4581.3	4625.6
b) Small Thermal	33	33	33	33	33	33	33	33	33	33	33	33	33	33	32.5	32.5
c) Combustion Turbines	2086	2086	2090	2104	2106	2108	2106	2104	2101	1644	1292	1565	1797	1902	1961.5	1982.6
d) Cogeneration (includes plant sales)	1500	1499	1517	1507	1504	1501	1503	1501	1506	1513	1513	1283	1506	1494	1485.9	1488.8
e) Exclude Plant Sales	-142	-142	-142	-142	-142	-142	-142	-142	-142	-142	-137	-124	-142	-142	-140.4	-140.7
f) Thermal PURPA/NUGS	168	168	154	137	147	145	145	153	161	181	180	196	196	180	163.6	161.3
g) Thermals classified as Renewables	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54.2	54.2
h) Thermal Installation Imports from the East	1916	1916	1916	1856	1916	1916	1916	1916	1916	1526	1456	1675	1710	1916	1838.8	1849.0
i) ... Total	10490	10489	10497	10423	10493	10490	10489	10493	10317	9449	7978	7956	9053	10312	9977.5	10053.5
7. **Total Step I Hydro Load (1929 water) 9/**	9897	9970	9536	9233	10865	12301	12171	11628	10474	9770	12266	12974	11761	11382	11107.0	11157.8
a) Hydro Maintenance included as load	31	26	9	9	4	0	0	0	5	7	8	20	14	50	12.3	11.3
b) Coordinated Hydro Model Load (1929 water) 10/	10439	10435	10101	10186	11807	13377	13122	12240	11175	10541	13065	13752	13114	12079	11933.5	12011.8

1/ Step I Loads and Resources for the U.S. Optimum Study (04-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Total regional firm load plus pumping. The annual average (aMW) includes the leap year.
2/ The Step I critical period begins 16 August 1928 and ends 29 February 1932.
3/ Source is the 1997 BPA Whitebook (unpublished).
4/ Includes uniform export of 1/2 Canadian Entitlement, 1/2 remained in region.
5/ Amount of import thermal installation capacity that is not used in the PNWA.
6/ Skagit River Treaty power from BC Hydro.
7/ Flows of Power into the region from thermal resources not identified with a specific thermal installation and not coordinated with PNWA.
8/ Line 1(a)+ line 2(j) + line 3(d) + line 4(e).
9/ Hydro load for U.S. projects located upstream of Bonneville Dam (except hydro independents), line 5 minus line 6(i).
10/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintence plus Non-Step I Coordianted Hydro.

TABLE 1B
2003-04 ASSURED OPERATING PLAN
DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES (MW) 1/

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. Pacific Northwest Area (PNWA) Load 2/	26101	26058	25919	28443	30489	32832	33589	33001	30777	29131	29203	27622	26616	26178
a) Annual Load Shape in Percent	78.60	78.60	77.33	72.76	74.18	73.69	73.93	72.17	72.94	72.92	72.92	75.03	77.33	79.24
2. Flows-Out of firm power from PNWA														
a) Canadian Entitlement Export (south+north) 3/	586	586	586	586	586	586	586	586	586	586	586	586	586	586
b) Exports to the East	248	248	229	216	229	229	229	218	211	217	217	198	249	251
c) SW Seasonal Exchange Exports	465	465	465	120	15	15	15	15	15	15	15	75	465	465
d) Other SW Exports	1174	1174	1207	1169	1124	1091	1079	1079	1079	1079	1129	1174	1181	1181
e) Plant Sale Exports	167	167	167	167	167	167	167	167	167	167	167	96	167	167
f) Surplus Firm Peak Exports	0	0	0	0	0	0	0	0	0	0	0	1987	1928	1881
g) Thermal Install. power used outside region 4/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) ...Subtotal	2640	2640	2653	2257	2120	2087	2075	2064	2057	2063	2113	4115	4575	4531
i) Exclude Plant Sales	-167	-167	-167	-167	-167	-167	-167	-167	-167	-167	-167	-96	-167	-167
j) ...Total	2473	2473	2486	2090	1953	1920	1908	1897	1890	1896	1946	4019	4409	4364
3. Load served by Flows-In of firm power except Step I thermal installations														
a) Non-thermal firm imports from north 5/	-146	-146	-146	-146	-133	-147	-169	-193	-223	-146	-146	-146	-146	-146
b) Flows-in from SW seasonal exchanges	0	0	0	0	-376	-376	-376	-376	-46	-12	-12	0	0	0
c) Non-Coord. Thermal Resc.from SW (not TI) 6/	0	0	0	-422	-429	-429	-429	-429	0	0	0	0	0	0
d) ...Total	-146	-146	-146	-568	-938	-952	-974	-998	-269	-158	-158	-146	-146	-146
4. Load served by non-Step I resources located within the PNWA														
a) Hydro Independents (1937 water)	-2050	-2028	-1937	-1787	-1633	-1594	-1548	-1664	-1787	-1995	-2003	-2169	-2209	-2116
b) Non-Step I Coordinated Hydro (1937 water)	-2451	-2383	-2477	-2438	-2331	-2249	-2107	-1944	-1914	-1945	-1979	-2053	-2275	-2451
c) Non-Thermal PURPA/NUGS	-117	-117	-110	-102	-105	-101	-101	-105	-107	-120	-120	-130	-131	-124
d) Miscellaneous Resources	-4	-4	-4	-4	-304	-304	-304	-304	-304	-4	-4	-4	-4	-4
e) ...Total (1937)	-4622	-4531	-4528	-4331	-4373	-4248	-4060	-4017	-4112	-4063	-4106	-4357	-4619	-4694
5. Total Step I System Firm Loads (1937water) 7/	23807	23855	23731	25635	27131	29552	30463	29883	28286	26807	26886	27139	26261	25703
6. Step I Thermal Installations														
a) Large Thermal (includes plant sales)	5373	5373	5373	5373	5373	5373	5373	5373	5108	5055	3885	3777	3685	5373
b) Small Thermal	38	38	38	41	41	41	41	41	41	38	38	38	38	38
c) Combustion Turbines	2236	2058	1999	2477	2487	2495	2495	2488	2480	2019	1580	2066	2239	2231
d) Cogeneration (includes plant sales)	1574	1574	1574	1563	1563	1563	1563	1563	1563	1574	1574	1329	1574	1574
e) Exlude Plant Sales	-167	-167	-167	-167	-167	-167	-167	-167	-167	-167	-167	-96	-167	-167
f) Thermal PURPA/NUGS	175	175	166	153	158	152	151	157	161	179	179	195	197	185
g) Thermals classified as Renewables	55	55	55	55	55	55	55	55	55	55	55	55	55	55
h) Thermal Installation Imports from the East	1635	1635	1756	1768	1833	1853	1800	1775	1645	1358	1358	1412	1242	1597
i) ...Total	10919	10741	10793	11262	11343	11365	11312	11285	10885	10112	8503	8776	8863	10886
7. Step I Hydro Load (1937 water) 8/	12888	13113	12938	14372	15788	18187	19152	18598	17401	16695	18384	18363	17398	14816
a) Hydro Maintenance included as load	4606	4043	3787	3208	2935	2037	1561	2289	2633	2751	2483	2360	2202	3721
b) Coordinated Hydro Model Load (1937 water) 9/	19945	19539	19202	20019	21054	22474	22820	22832	21948	21390	22846	22776	21875	20988

1/ Step I Loads and Resources for the U.S. Optimum Study (04-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Total regional firm load plus pumping.
2/ Source is the 1997 BPA Whitebook (unpublished).
3/ Includes uniform export of 1/2 Canadian Entitlement, 1/2 remained in region.
4/ Amount of import thermal installation capacity that is not used in the PNWA.
5/ Skagit River Treaty power from BC Hydro.
6/ Flows of Power into the region from thermal resources not identified with a specific thermal installation and not coordinated with PNWA.
7/ Line 1(a)+ line 2(j) + line 3(d) + line 4(e).
8/ Hydro load for U.S. projects located upstream of Bonneville Dam (except hydro independents), line 5 minus line 6(i).
9/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintence plus Non-Step I Coordianted Hydro.

TABLE 2
2003-04 ASSURED OPERATING PLAN
DETERMINATION OF THERMAL DISPLACEMENT MARKET
(Energy in aMW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	June	July	Annual Average	CP Ave (42.5 Mon)
1. STEP I THERMAL INSTALLATIONS																
a) From Table 1A, line 6(i)	10490	10489	10497	10423	10493	10490	10489	10493	10317	9449	7978	7956	9053	10312	9977.5	10053.5
2. MINIMUM THERMAL GENERATION																
a) Large Thermal Min. Generation	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147.0	147.0
b) Cogen & Small Thermal Min. Gen.	427	427	427	427	427	427	427	427	427	427	427	193	427	427	407.2	410.2
c) NUGS Thermal Min Generation	56	56	51	46	49	48	48	51	54	60	60	65	65	60	54.5	53.8
d) ...Total Minimum Generation	630	630	625	620	623	622	622	625	628	634	634	405	639	634	608.7	610.9
3. DISPLACEABLE THERMAL RESOURCES	9860	9859	9872	9804	9870	9868	9867	9868	9689	8815	7344	7551	8413	9678	9368.8	9442.5
4. SYSTEM SALES																
a) Total Flows-Out (Table 1A, Line 2(h))	1933	1984	2022	1412	1420	1371	1355	1335	1419	1306	1339	3035	3629	3347	1971.0	1904.2
b) Exclude Seasonal Exchange Exports	-191	-191	-225	-15	0	0	0	0	0	0	0	-26	-158	-162	-64.8	-63.0
c) Exclude Plant Sales Exports	-142	-142	-142	-142	-142	-142	-142	-142	-142	-142	-137	-124	-142	-142	-140.4	-140.7
d) Exclude Flow-Through Transfers	-293	-293	-297	-309	-304	-304	-304	-304	-295	-293	-282	-278	-278	-293	-295.5	-296.6
e) Exclude Can Entitlement (out of the PNWA)	-267	-267	-267	-267	-267	-267	-267	-267	-267	-267	-267	-267	-267	-267	-267.2	-267.2
f) ...Total System Sales	1039	1090	1091	679	706	658	642	621	715	603	653	2340	2785	2482	1203.1	1136.8
g) Uniform Average Annual System Sales	1203	1203	1203	1203	1203	1203	1203	1203	1203	1203	1203	1203	1203	1203	1203.1	1203.1
5. THERMAL DISPLACEMENT MARKET	8657	8656	8669	8600	8666	8665	8664	8665	8486	7611	6141	6348	7210	8475	8165.7	8239.4

Notes:

Line 2a Large Thermal minimum generation consists of Jim Bridger.

Line 2b Cogen & Small Thermal Minimum Generation Includes Spokane Muni Solid Waste, Tacoma Steam Plant, EWEB Weyerhauser cogen, and PP&L cogen plants.

Line 2c 60% of the total NUGS is thermal. Non-displaceable NUGS generation is 1/3 of the thermal NUGS.

Line 2d Total Minimum Thermal Generation, the sum of lines 2(a) through line 2(c).

Line 3 Step I Thermal Installation Resources that are displaceable, line 1(a) minus line 2(d).

Line 4c Plant sales include Longview Fibre and approximately 22 percent of Boardman.

Line 4d Flow-through transfers include Flows-in that support Flows-Out, i.e., SW imports and the net of seasonal exchange imports and exports.

Line 4f System Sales are total exports excluding exchanges, plant sales, flow-through transfers, and the Canadian Entitlement. The sum of lines 4(a) through line 4(e).

Line 4g Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.

Line 5 PNWA Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNWA firm loads, lines 3 minus line 4(g).

TABLE 3
2003-04 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR STEP II AND STEP III STUDIES

PACIFIC NORTHWEST AREA (PNWA) LOAD						STEP II STUDY		STEP III STUDY		
Period	PNWA 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
August 1-15	20556	93.98	26101	78.60	10490	17700.8	7211.0	15386.0	4896.1	August 1-15
August 16-31	20478	93.62	26058	78.60	10489	17633.7	7144.9	15327.6	4838.8	August 16-31
September	20042	91.63	25919	77.33	10497	17258.2	6761.0	15001.2	4504.1	September
October	20695	94.61	28443	72.76	10423	17820.4	7397.0	15489.9	5066.6	October
November	22616	103.40	30489	74.18	10493	19474.6	8982.0	16927.8	6435.2	November
December	24195	110.62	32832	73.69	10490	20834.8	10344.6	18110.1	7619.9	December
January	24832	113.53	33589	73.93	10489	21383.3	10893.8	18586.9	8097.4	January
February	23818	108.89	33001	72.17	10493	20509.7	10016.8	17827.5	7334.6	February
March	22449	102.63	30777	72.94	10317	19330.9	9014.1	16802.9	6486.0	March
April 1-15	21250	97.15	29131	72.92	9449	18298.7	8849.9	15905.7	6456.8	April 1-15
April 16-30	21339	97.56	29203	72.92	7978	18375.1	10397.0	15972.0	7993.9	April 16-30
May	20726	94.76	27622	75.03	7956	17847.2	9891.3	15513.2	7557.3	May
June	20581	94.09	26616	77.33	9053	17722.8	8670.0	15405.1	6352.2	June
July	20743	94.83	26178	79.24	10312	17861.9	7549.8	15525.9	5213.9	July
Annual Average 7/	21872.9	100.00		75.02	9977.5	18835.1	8857.6	16371.9	6394.4	Annual Average
SI CP Average (42.5)	21967.8			74.93	10053.5					
SII CP Average (20)	22118.8				10082.2	19046.8	8964.6	←		Sep-Ap2
SIII CP Average (6)	23204.1				10166.7			17368.3	7201.6 ←	Nov-Ap2
						Input 5/ →	**8964.6**	Input 6/ →	**7201.6**	
August 1-31	20515.4	93.8	26101.2	78.60	10489.3	17666.2	7176.9	15355.8	4866.6	August 1-31
April 1-30	21294.4	97.4	29202.9	72.92	8713.5	18336.9	9623.4	15938.9	7225.4	April 1-30

1/ The PNWA load does not include the exports, but does include pumping. The computation of the load shape for Step II/III studies used these loads.

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

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

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 (CP) average generation for the Step II hydro studies and is used to calculate the residual hydro loads.

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

7/ The Annual Average is for 2003-04 operating year which is a leap year. The CP averages are for the historic water years.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2003-04 ASSURED OPERATING PLAN

	BASIC DATA		STEP I			STEP II				STEP III			
PROJECTS	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
HYDRO RESOURCES													
CANADIAN													
Mica			7000			7000							
Arrow			7100			7100							
Duncan			1400			1400							
Subtotal			15500			15500							
BASE SYSTEM													
Hungry Horse	4	428	3072	272	101	3008	182	116	103	3008	323	246	104
Kerr	3	160	1219	157	123	1219	156	112	122	1219	154	141	115
Thompson Falls	6	85	0	85	56	0	85	53	58	0	85	65	56
Noxon Rapids	5	554	231	549	153	0	554	134	202	0	554	176	201
Cabinet Gorge	4	239	0	239	102	0	239	90	118	0	239	114	116
Albeni Falls	3	50	1155	22	23	1155	20	22	20	1155	14	14	21
Box Canyon	4	74	0	71	46	0	70	45	48	0	69	56	47
Grand Coulee	24+3SS	6684	5185	6352	2010	5072	6336	1788	2386	5072	5706	1232	2284
Chief Joseph	27	2535	0	2535	1069	0	2535	974	1307	0	2535	721	1238
Wells	10	840	0	840	421	0	840	389	489	0	840	293	443
Chelan	2	54	677	51	38	676	51	36	45	676	51	51	43
Rocky Reach	11	1267	0	1266	575	0	1266	532	693	0	1266	394	646
Rock Island	18	513	0	513	256	0	513	239	301	0	513	179	278
Wanapum	10	986	0	986	518	0	986	482	603	0	986	347	539
Priest Rapids	10	912	0	912	510	0	912	476	574	0	912	353	510
Brownlee	5	675	975	675	241	974	675	313	316	974	675	267	314
Oxbow	4	220	0	220	99	0	220	125	128	0	220	121	128
Ice Harbor	6	693	0	693	212	0	693	231	302	0	693	184	303
McNary	14	1127	0	1127	623	0	1127	604	768	0	1127	481	717
John Day	16	2484	535	2484	939	0	2484	920	1254	0	2484	722	1216
The Dalles	22+2F	2074	0	2074	747	0	2074	731	993	0	2074	589	970
Bonneville	18+2F	1088	0	1047	565	0	1046	551	683	0	1047	456	642
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 and Canadian System Hydro 1/		23742	29445	23170	9427	28500	23064	8965	11513	13000	22567	7202	10931
ADDITIONAL STEP I PROJECTS													
Libby	5	600	4980	558	202								
Boundary	6	1055	0	855	368								
Spokane River Plants	24	173	104	168	100								
Hells Canyon	3	450	0	410	192	NOT APPLICABLE TO STEP II & III							
Dworshak	3	450	2015	443	128								
Lower Granite	6	932	0	930	211								
Little Goose	6	932	0	928	205								
Lower Monumental	6	932	0	922	210								
Pelton, Rereg., & RB	7	423	274	418	127								
Total added step 1		5947	7373	5633	1742								
THERMAL INSTALLATION 2/				11312	10053		11312	10082			11312	10167	
RESERVES, HYDRO MAINTENANCE 3/				-4249	-11		-2314	0			-2011	0	
TOTAL RESOURCES				35866	21211		32062	19047			31867	17368	
STEP I, II, & III LOADS 4/				30463	21211		28924	19047			25141	17368	
SURPLUS				5403	0		3138	0			6726	0	
CRITICAL PERIOD	Starts			August 16, 1928			September 1, 1943				November 1, 1936		
	Ends			February 29, 1932			April 30, 1945				April 30, 1937		
	Length (Months)			42.5 Months			20 Months				6 Months		
	Study Identification			04-41			04-42				04-13		

1/ The above totals are correct, but may not equal the sum of the above values due to rounding.

2/ From Tables 1 and 3

3/ Peak reserves for Step I, II, III are 8 percent of January peak load from Table 3. Energy reserve deductions only include the hydro maintenance for Step I study (reserves have been included in thermal plant energy capability) from Table 1A, line 7(a).

4/ Step I energy load from Table 1A, line 5 and January peak load from Table 1B, line 5. Step II & III energy load from Table 3. Step II & III peak load is equal to the step II or step III annual average load multiplied by the ratio of the PNWA January peak load to the PNW annual average load.

TABLE 4M
(Metric Units)
SUMMARY OF POWER REGULATIONS
FROM 2003-04 ASSURED OPERATING PLAN

	BASIC	DATA	STEP I			STEP II				STEP III 4/			
PROJECTS	NUMBER OF UNITS	NOMINAL 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
HYDRO RESOURCES													
CANADIAN													
Mica			8635			8635							
Arrow			8758			8758							
Duncan			1727			1727							
Subtotal			19119			19119							
BASE SYSTEM													
Hungry Horse	4	428	3789	272	101	3710	182	116	103	3710	323	246	104
Kerr	3	160	1504	157	123	1504	156	112	122	1504	154	141	115
Thompson Falls	6	85	0	85	56	0	85	53	58	0	85	65	56
Noxon Rapids	5	554	285	549	153	0	554	134	202	0	554	176	201
Cabinet Gorge	4	239	0	239	102	0	239	90	118	0	239	114	116
Albeni Falls	3	50	1425	22	23	1425	20	22	20	1425	14	14	21
Box Canyon	4	74	0	71	46	0	70	45	48	0	69	56	47
Grand Coulee	24+3SS	6684	6396	6352	2010	6256	6336	1788	2386	6256	5706	1232	2284
Chief Joseph	27	2535	0	2535	1069	0	2535	974	1307	0	2535	721	1238
Wells	10	840	0	840	421	0	840	389	489	0	840	293	443
Chelan	2	54	835	51	38	834	51	36	45	834	51	51	43
Rocky Reach	11	1267	0	1266	575	0	1266	532	693	0	1266	394	646
Rock Island	18	513	0	513	256	0	513	239	301	0	513	179	278
Wanapum	10	986	0	986	518	0	986	482	603	0	986	347	539
Priest Rapids	10	912	0	912	510	0	912	476	574	0	912	353	510
Brownlee	5	675	1203	675	241	1201	675	313	316	1201	675	267	314
Oxbow	4	220	0	220	99	0	220	125	128	0	220	121	128
Ice Harbor	6	693	0	693	212	0	693	231	302	0	693	184	303
McNary	14	1127	0	1127	623	0	1127	604	768	0	1127	481	717
John Day	16	2484	660	2484	939	0	2484	920	1254	0	2484	722	1216
The Dalles	22+2F	2074	0	2074	747	0	2074	731	993	0	2074	589	970
Bonneville	18+2F	1088	0	1047	565	0	1046	551	683	0	1047	456	642
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 and Canadian System Hydro 1/		23742	36320	23170	9427	35155	23064	8965	11513	16036	22567	7202	10931
ADDITIONAL STEP I PROJECTS						NOT APPLICABLE TO STEP II & III							
Libby	5	600	6143	558	202								
Boundary	6	1055	0	855	368								
Spokane River Plants	24	173	128	168	100								
Hells Canyon	3	450	0	410	192								
Dworshak	3	450	2486	443	128								
Lower Granite	6	932	0	930	211								
Little Goose	6	932	0	928	205								
Lower Monumental	6	932	0	922	210								
Pelton, Rereg., & RB	7	423	338	418	127								
Total added step 1		5947	9095	5633	1742								
THERMAL INSTALLATION 2/				11312	10053		11312	10082			11312	10167	
RESERVES, HYDRO MAINTENANCE 3/				-4249	-11		-2314	0			-2011	0	
TOTAL RESOURCES				35866	21211		32062	19047			31867	17368	
STEP I, II, & III LOADS 4/				30463	21211		28924	19047			25141	17368	
SURPLUS				5403	0		3138	0			6726	0	
CRITICAL PERIOD	Starts		August 16, 1928			September 1, 1943				November 1, 1936			
	Ends		February 29, 1932			April 30, 1945				April 30, 1937			
	Length (Months)		42.5 Months			20 Months				6 Months			
	Study Identification		04-41			04-42				04-13			

1/ The above totals are correct, but may not equal the sum of the above values due to rounding

2/ From Tables 1 and 3

3/ Peak reserves for Step I, II, III are 8 percent of January peak load from Table 3. Energy reserve deductions only include the hydro maintenance for Step I study (reserves have been included in thermal plant energy capability) from Table 1A, line 7(a).

4/ Step I energy load from Table 1A, line 5 and January peak load from Table 1B, line 5. Step II & III energy load from Table 3. Step II & III peak load is equal to the step II or III annual average load multiplied by the ratio of the PNWA January peak load to the PNW annual average load.

TABLE 5
(English & Metric Units)
COMPUTATION OF CANADIAN ENTITLEMENT FOR
2003-04 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 04-42)
B. Optimum Power Generation in the U.S. Only (From 04-12)
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km3) Reduction in Total Canadian Treaty Storage (From 04-22)

	CAPACITY ENTITLEMENT		
Determination of Dependable Capacity Credited to Canadian Storage (MW)	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	8964.6	8965.9	8927.4
Step III - Critical Period Average Generation 2/	7201.6	7201.6	7201.6
Gain Due to Canadian Storage	1763.0	1764.3	1725.8
Average Critical Period Load Factor in percent 3/	74.93	74.93	74.93
Dependable Capacity Gain 4/	2352.9	2354.6	2303.3
Canadian Share of Dependable Capacity 5/	1176.4	1177.3	1151.6

	ENERGY ENTITLEMENT		
Determination of Increase in Average Annual Usable Energy (aMW)			
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8855.1	8856.3	8818.5
Thermal Displacement Energy 7/	2395.1	2396.3	2404.7
Other Usable Secondary Energy 8/	105.3	104.9	110.9
System Annual Average Usable Energy	11355.5	11357.6	11334.1
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6392.4	6392.4	6392.4
Thermal Displacement Energy 7/	3455.4	3455.4	3455.4
Other Usable Secondary Energy 8/	433.1	433.1	433.1
System Annual Average Usable Energy	10280.9	10280.9	10280.9
Average Annual Usable Energy Gain 9/	1074.6	1076.7	1053.3
Canadian Share of Average Annual Energy Gain 5/	537.3	538.4	526.6

1/ Step II values were obtained from the 04-42, 04-12, and 04-22 studies, respectively.
2/ Step III values were obtained from the 04-13 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 February).
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

	1999-00	2000-01	2001-02	2002-03	2003-04
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	20817.8	21107.8	21641.7	21769.7	21872.9
Annual/January Load (%)	85.9	87.4	88.0	88.0	88.1
Critical Period (CP) Load Factor (%)	75.3	75.1	76.7	76.4	74.9
Annual Firm Exports 1/	1202.7	1067.1	1156.3	1317.3	1322.1
Annual Firm Surplus (MW) 2/	708.1	739.7	313.7	323.7	374.7
THERMAL INSTALLATIONS (MW) 3/					
January Peak Capability	11341	11520	11433	11545	11312
CP Energy	9019	9521	9496	10081	10053
CP Minimum Generation	1071	858	853	622	611
Average Annual System Export Sales	1392	1413	997	1419	1203
Average Annual Displaceable Market	6490	7179	7493	7958	8166
HYDRO CAPACITY (MW)					
Total Installed	29786	29836	29827	29827	29689
Base System	23856	23889	23880	23880	23742
STEP I/II/III CP (MONTHS)	42/20/7	42/20/7	42.5/20/6.5	42.5/20/6	42.5/20/6
BASE STREAMFLOWS AT THE DALLES (cfs) 4/					
Step I 50-yr. Average Streamflow	181664	181663	181663	181663	181663
Step I CP Average	114496	114496	114401	114401	114401
Step II CP Average	101525	101525	101525	101525	101525
Step III CP Average	64960	64959	58482	64878	64878
BASE STREAMFLOWS AT THE DALLES (m^3/s) 4/					
Step I 50-yr. Average Streamflow	5144.15	5144.12	5144.12	5144.12	5144.12
Step I CP Average	3242.16	3242.16	3239.46	3239.46	3239.46
Step II CP Average	2874.86	2874.86	2874.86	2874.86	2874.86
Step III CP Average	1839.47	1839.43	1656.01	1837.14	1837.14
CAPACITY BENEFITS (MW)					
Step II CP Generation	9080.4	9032.9	9055.6	9049.2	8964.6
Step III CP Generation	6878.8	6859.6	6865.3	7260.6	7201.6
Step II Gain over Step III	2201.7	2173.3	2190.3	1788.6	1763.0
CANADIAN ENTITLEMENT	1461.9	1447.3	1427.1	1170.7	1176.4
Change due to Mica Reoperation	0.2	0.0	0.0	-0.7	-0.9
Benefit in Sales Agreement	200.0	192.0	187.0	167.0	0.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm Hydro	8990.3	8967.3	8966.5	8942.9	8855.1
Step II Thermal Displacement	2129.5	2183.3	2306.6	2343.6	2395.1
Step II Other Usable Secondary	193.5	148.7	135.8	129.6	105.3
Step II System Annual Average Usable	11313.3	11299.3	11408.9	11416.1	11355.5
Step III Annual Firm Hydro	6422.2	6541.1	6573.9	6448.1	6392.4
Step III Thermal Displacement	3182.0	3239.8	3294.0	3431.4	3455.4
Step III Other Usable Secondary	590.1	501.5	475.9	467.7	433.1
Step III System Annual Average Usable	10194.3	10282.4	10343.8	10347.2	10280.9
CANADIAN ENTITLEMENT	559.5	508.4	532.6	534.5	537.3
Change due to Mica Reoperation	-0.8	0.7	0.4	1.7	-1.1
ENTITLEMENT in Sales Agreement	103.0	99.0	95.0	93.0	0.0
STEP II PEAK CAPABILITY (MW)	32421	32481	32501	32544	32062
STEP II PEAK LOAD (MW)	28386	28779	27650	28734	28924
STEP III PEAK CAPABILITY (MW)	32206	32268	32260	32352	31867
STEP III PEAK LOAD (MW)	24318	24983	24034	24949	25141

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).

2. Average annual firm surplus is the additional shaped load including the surplus shaped in the following periods:

AOP Study	Amount Shaped (MW)
1999-00	4237 May and June.
2000-01	471 1 August through April 30 and 1537 May through July
2001-02	1877 May and June.
2002-03	1937 May and June.
2003-04	1491 May through July.

3. Thermal installations include thermal imports, all existing and planned thermal resources, combustion turbines, cogeneration, renewable thermal, thermal PURPA/NUGS, minus seasonal exchange imports and plant sales.

4. The 1990 level modified flows were used and no additional irrigation depletions were anticipated for the 2003-04 level. There is, however, an adjustment for Grand Coulee pumping and return flow.

CHART 1

2003-04 DDBP STUDIES WITHOUT LIBBY
DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)