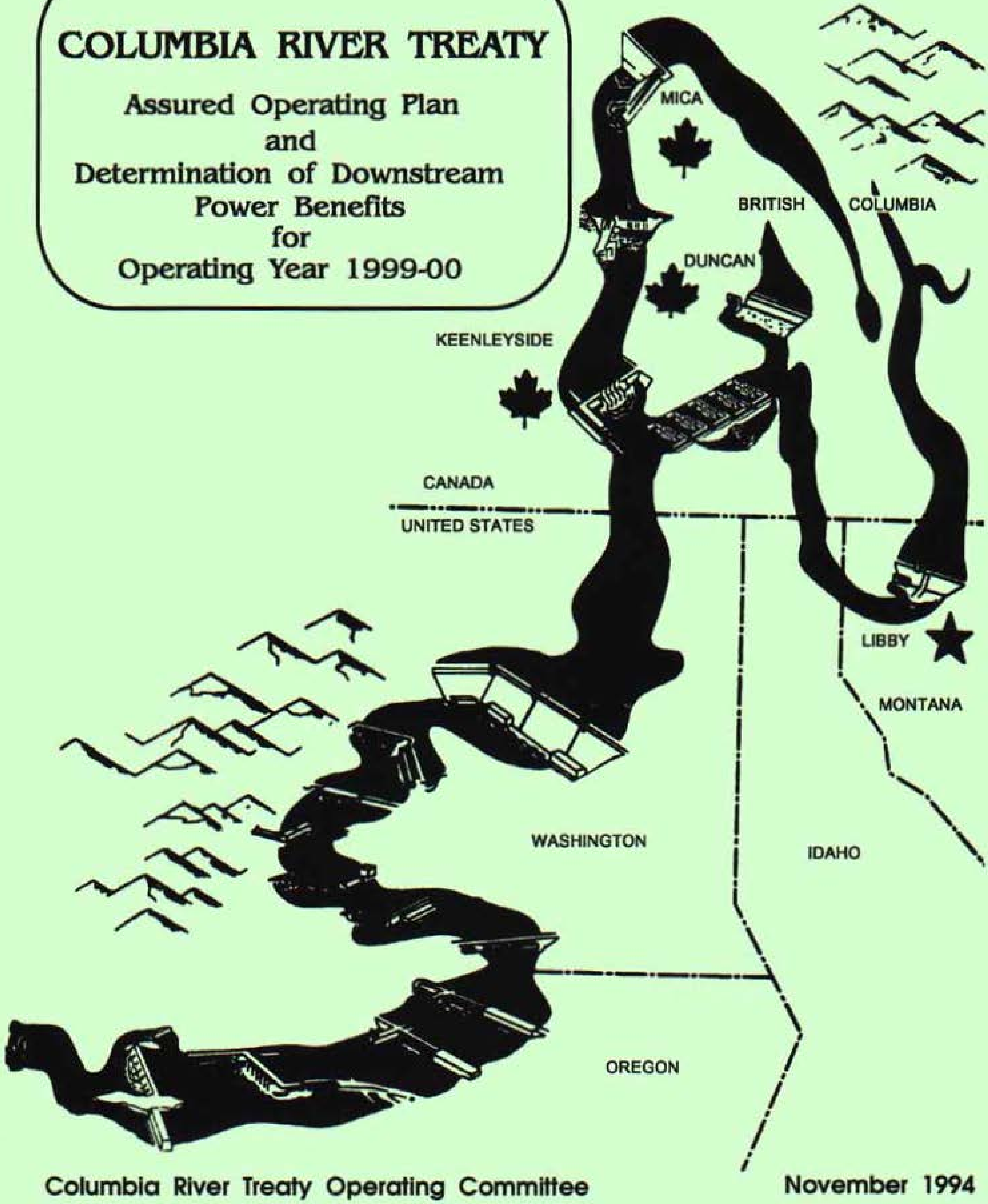
COLUMBIA RIVER TREATY

Assured Operating Plan
and
Determination of Downstream Power Benefits
for
Operating Year 1999-00



Columbia River Treaty Operating Committee

November 1994

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
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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 be agreed to by the Entities for the operation of the Columbia River Treaty storage in Canada during the sixth succeeding year. This plan will provide to the Entities information for the sixth succeeding year for planning the power systems in their respective countries which are dependent on or coordinated with the operation of the Canadian storage projects.

This Assured Operating Plan 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 Entity Agreements on:

- 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.
- Preparation of the 1998-99, 1999-00, and 2000-01 Assured Operating Plan and Determination of Downstream Power Benefit Studies[4].

POP is based on criteria contained in Annex A and Annex B of the Columbia River Treaty,[5] Protocol,[6] Terms of Sale,[7] and the Columbia River Treaty Flood Control Operating Plan.[8]

The Assured Operating Plan consists of:

(a) The Operating Rule Curve for the whole of the Canadian storage, computed from the individual project Critical Rule Curves, Assured Refill Curves, and Variable Refill Curves, and the individual project Upper Rule Curves.

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

2. System Regulation Studies

In accordance with Annex A, Paragraph 7, of the Treaty, the Columbia River Treaty Operating Committee conducted system regulation studies reflecting Canadian storage operation for optimum generation in both Canada and the United States. Downstream power benefits were computed with the Canadian storage operation based on the operating rules specified herein. For this operation, there is a 0.8 aMW decrease in the Canadian Entitlement to annual average usable energy and a 0.2 MW increase in the entitlement to dependable capacity when compared to the operation for optimum generation in the United States alone. These are within the limits specified by the Treaty.

System Regulation Studies for the Assured Operating Plan were based on 1999-00 estimated loads and resources in the United States Pacific Northwest System and resources in the Columbia River Basin in British Columbia. The Entities agreed that the 1999-00 Assured Operating Plan would be based on a 30-year streamflow period and 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 1990 level, were used.[9]

The Critical Rule Curves for these studies were determined from the Bonneville Power Administration study of optimum power generation in both Canada and the United States. The study indicated a 42-month critical period for the United States system resulting from the low flows during the period from 1 September 1928 through 29 February 1932. With the exceptions 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 Criteria are based on historical inflow volumes. Although only 7.0 million acre-feet of usable storage at Mica 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 12 million acre-feet of usable storage at Mica for on-call flood control purposes.

3. Development of the Assured Operating Plan

This Assured Operating Plan was developed in accordance with Annex A, paragraph 7 of the Treaty and 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 were evaluated using the two tests described below.

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

To determine whether optimum 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.

In the studies for the 1999-00 Assured Operating Plan, the Canadian storage operation was operated to achieve a weighted sum of the three quantities that was greater than the weighted sum achieved under an operation of Canadian storage for optimum generation in the United States of America alone.

In order to achieve a weighted value for the three quantities, the Columbia River Treaty Operating Committee agreed for the 1999-00 Assured Operating Plan 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

After weighting each quantity, the three quantities were added, resulting in a net gain to the combined Canadian and United States systems with the study designed for optimum generation in Canada and the United States.

Table 2 shows the results from studies adopted for the 1999-00 Assured Operating Plan and from studies designed to achieve optimum generation in the United States alone.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Separate system regulation studies were developed reflecting (i) Canadian storage operation for optimum generation in both Canada and the United States, using the Mica Project operating criteria described in section 5(c) below, and (ii) Canadian storage operation for optimum generation in the United States alone. Using these Mica Project operating criteria, there is a 0.8 aMW decrease in entitlement to average annual energy and a 0.2 MW increase in entitlement to dependable capacity compared to an operation for optimum generation in the United States alone.

The Entities have determined that these changes are within the limits specified by the Treaty.

4. Operating Rule Curves

The operation of Canadian storage during the 1999-00 Operating Year shall be guided by an Operating Rule Curve for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, and operating rules for specific projects. The Operating Rule Curve is derived from the various curves described below. These operating rule curves are first determined for the individual Canadian projects and then summed to yield the Composite Operating Rule Curve for the whole of Canadian storage. This is in accordance with Article VII(2) of the Protocol.

(a) Critical Rule Curve

The Critical Rule Curve indicates the end-of-month storage content of Canadian storage during the critical period. It is designed to protect the ability of the United States system to serve firm load with the occurrence of flows no worse than those during the most adverse historical streamflow period. A tabulation of the Critical Rule Curves for Duncan, Arrow, Mica, and the Composite Critical Rule Curve for the whole of Canadian storage is included as Table 3.

(b) Refill Curve

The Refill Curve is a guide to operation of Canadian storage which defines the normal limit of storage draft to produce secondary energy in order to provide a high probability of refilling the storage. 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. The end of the refill period is considered to be 31 July.

The Refill Curve is defined by two curves, the assured refill curve and the variable refill curve, as discussed in the following sections. In each case, adjustment is made for water required for refill of upstream reservoirs when applicable. Tabulations of the variable refill curves and outflow schedules used in determining the variable refill curves and assured refill curves for Mica, Arrow, and Duncan are provided in Tables 4 - 6, respectively.

(1) Assured Refill Curve

The Assured Refill Curve indicates the end-of-month storage content required to assure refill of Canadian storage based on the 1930-31 water year, the system's second lowest historical volume of inflow during the 30-year record for the period January through July as measured at The Dalles, Oregon. A tabulation of the Assured Refill Curves for Mican, Arrow, and Duncan are included in Tables 4-6.

The outflows used in developing these Assured Refill Curves are not the same as the Power Discharge Requirements used in computing the Variable Refill Curves.

(2) Variable Refill Curve

The Variable Refill Curves give end-of-month storage contents for the period January through July required to refill Canadian storage during the refill period. They were based on historical inflow volumes and Power Discharge Requirements determined in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans.[1] The power discharge requirements used in the 1999-00 AOP are the same as those used in the 1998-1999 AOP. In the system regulation studies, the Power Discharge Requirement was made a function of the natural January - July runoff volume at The Dalles, Oregon. The Power Discharge Requirement used in computing the Variable Refill Curves was interpolated linearly between the values shown in Tables 4 - 6. In those years when the January to July runoff volume at The Dalles was less than 80 million acre-feet or greater than 110 million acre-feet, the discharge used was that specified for 80 and 110 million acre-feet, respectively.

Variable Refill Curves 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 1999-00, the Power Discharge Requirements will be based on the forecast of unregulated runoff at The Dalles.

(c) Limiting Rule Curve (ECC Lower Limit)

The Limiting Rule Curves indicate end-of-month storage contents which must be maintained to protect the ability of the system to meet firm load during the period 1 January - 31 March in the event that the Variable Refill Curves 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 Variable Refill Curve to be no lower than the Limiting Rule Curve. The Limiting Rule Curve is developed for 1936-37 water conditions. Limiting Rule Curves for Mica, Arrow, and Duncan are shown in Tables 4 - 6, respectively.

(d) Upper Rule Curve

The Upper Rule Curves indicate the end-of-month storage content to which each individual Canadian storage project shall be evacuated for flood control. The Upper Rule Curves used in the studies were based upon Flood Control Storage Reservation Diagrams contained in the Columbia River Treaty Flood Control Operating Plan[8] and analysis of system flood control simulations.[10] Flood control curves 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 2 million acre-feet of flood control storage space from Arrow to Mica. In actual operation, the Flood Control Storage Reservation Curves will be computed as outlined in the Flood Control Operating Plan, using the latest forecast of runoff available at that time.

(e) Definition of Operating Rule Curve

During the period 1 August through 31 December, the Operating Rule Curve is defined as the Critical Rule Curve for the first year of the critical period or the Assured Refill Curve, whichever is higher. During the period 1 January through 31 July, the Operating Rule Curve is defined as the higher of the Critical Rule Curve and the Assured Refill Curve; unless the Variable Refill Curve is lower than this value, then it is defined as the Variable Refill Curve. During the period 1 January through 31 March, it will not be lower than the Limiting Rule Curve. The Operating Rule Curve meets all requirements for flood control operation. Composite Operating Rule Curves for the whole of Canadian storage for 30 years of historical record are included as Table 10 to illustrate the probable future range of these curves based on historical conditions.

5. Operating Rules

A 30-year System Regulation Study[11] was utilized to develop and test the operating rules and rule curves. It contains the agreed-upon operating constraints such as maximum and minimum project elevations, discharges, draft rates, etc. These constraints are included as part of this operating plan.

The following rules, used in the 30-year System Regulation Study, will apply to the operation of Canadian storage in the 1999-00 Operating Year.

(a) Operation Above Operating Rule Curve

The whole of the Canadian storage will be drafted to its Operating Rule Curve 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) below.

(b) Operation Below Operating Rule Curve

The whole of Canadian storage will be drafted below its Operating Rule Curve as required to produce optimum generation to the extent that a System Regulation Study determines that proportional draft below the Operating Rule Curves/Energy Content Curves is required to produce the hydro firm energy load carrying capability of the United States system as determined by the applicable Critical Period Regulation study. Energy Content Curves for United States reservoirs are equivalent to Operating Rule Curves. Proportional draft between rule curves will be determined as described in the Principles and Procedures.[1]

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 the end of previous period Arrow storage content as shown in Table 1. Mica monthly outflows will be increased above the values shown in the table in the months from October through June if required to avoid storage above the Upper Rule Curve.

Under this Assured Operating Plan, Mica storage releases in excess of 7 million acre-feet 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 million acre-feet, 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 million acre-feet 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 1999-00 Assured Operating Plan and have been operated as run-of-river projects. Corra Linn and Kootenay Canal were also included in the study and operated in accordance with International Joint Commission rules for Kootenay Lake.

6. Implementation

The Entities have agreed that each year a Detailed Operating Plan will be prepared for the immediately succeeding operating year. Such Detailed Operating Plans 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 Detailed Operating Plan for 1999-00 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 operating rules to be used in implementation of the Detailed Operating Plan for 1999-00 are generally the same as the operating rules described in this document. The data and criteria contained herein may be reviewed, and updated as agreed by the Entities, to form the basis for a Detailed Operating Plan for 1999-00. Failing agreement on updating the data and/or criteria, the Detailed Operating Plan for 1999-00 will include the rule curves, Mica operating criteria, and other data and criteria provided in this Assured Operating Plan. Actual operation during the 1999-00 Operating Year shall be guided by the Detailed Operating Plan.

The values used in the Assured Operating Plan studies to define the various rule curves were month-end values only. In actual operation, it is necessary to operate in such a manner during the course of each month that these month-end values can be observed in accordance with the operating rules. Because of the normal variation of power load and streamflow during any month, straight line interpolation between the month-end points should not be assumed.

During the storage drawdown season, Canadian storage should not be drafted below its month-end point at any time during the month 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-month 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,[8] 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 from each day through the end of the refill season.

7. Delivery of Canadian Entitlement

On 1 April 1998 and on 1 April 1999, the portions of the Canadian Entitlement to downstream power benefits related to the operation of Duncan and Arrow dams, respectively, 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[12]. The Entities are currently preparing agreements for Delivery and Disposition of the Canadian Entitlement (beginning 1 April 1998) and it is expected that these agreements will be evidenced by an Exchange of Notes in 1995. Since these agreements have not yet been authorized by Canada and the United States, this Assured Operating Plan has been prepared on the basis that the portion of the Canadian Entitlement attributable to Duncan will be returned to Canada starting 1 April 1998, and the portion attributable to Arrow will be returned starting 1 April 1999.

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,[13] executed 28 July 1992. This agreement describes the existing points of interconnection. The Entities have agreed that delivery of the lessor of 300 MW or 50% of the Canadian Entitlement attributable to Duncan and Arrow, net of transmission loss, will be delivered at the Nelway Point of Delivery and the Waneta Point of Delivery. The balance of the Canadian Entitlement attributable to Duncan and Arrow, net of transmission loss, will be delivered at the Blaine No. 1 Point of Delivery and the Blaine No. 2 Point of Delivery.

For the period 1 August 1999 through 30 September 1999, the Entities agree that the transmission loss applicable to this arrangement will be 3%. For the period 1 October 1999 to 31 July 2000, the transmission loss will be as agreed to by the Entities at the time, or before, deliveries commence.

8. Capacity/Energy Entitlement Scheduling Guidelines

The scheduling guidelines for return of the Canadian Entitlement will be those agreed to by the Entities at the time, or before, deliveries commence.

9. Summary of Changes From Previous Year

Data from the five most recent Assured Operating Plans are summarized in Table 11. Firm energy shifting was not included in the 1996-97, 1997-98, 1998-99, and the 1999-00 operating plan studies. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Resources

Loads for the 1999-00 AOP were based on the 1993 Whitebook medium case forecast developed by BPA in September 1993. The Pacific Northwest Area firm energy load increased by 338.2 annual aMW. The total exports, not including firm surplus energy, increased by 127.4 aMW. The firm surplus energy increased by 173.5 aMW. The increase in exports is mainly due to the increased Canadian Entitlement Return.

The total energy capability of the thermal installations increased by 551.6 aMW. Major thermal resource changes included:

1) Decrease of 61 aMW due to the removal of the Small Thermal resources,
2) Combustion Turbine resource increases of 67.0 aMW due to facilities upgrade at Beaver and other small changes,
3) Co-generation increased 664.0 aMW due the addition of four new projects: Coyote Springs, PP&L Miscellaneous, Scott Paper, and Wauna,
4) Centralia large thermal generation decreased by 36 aMW,
5) Thermal Non-Utility Generation (NUGs) decreased by 16.1 aMW,
6) Decrease of 67.0 aMW in PP&L (WYM) to PP&L Thermal import.

(b) Operating Procedures

The 1990 level modified base flows were again used, with no additional depletion to the 2000 level, based on the recommendation of the Columbia River Water Management Group. Grand Coulee pumping adjustments and return flow, however, were included. The 1999-00 AOP also includes minor adjustments in the Step I flows for Merwin.

The spill and bypass assumptions for the 1999-00 AOP studies are the same as in the 1998-99 AOP studies, except that, for operating year 1999-00, it was assumed that fish bypass installations were implemented at Priest Rapids, Rocky Reach and Rock Island.

The Entities completed a Step I refill study and incorporated the resulting Power Discharge Requirements (PDRs) in the 1999-00 AOP. New Energy Content Curve Lower Limits (ECCLL) were developed for the Step I system based on 1937 water conditions. These studies are consistent with PNCA procedures, which includes starting the system full 1 August 1936 and adjusting the load until the system is empty 30 April 1937. The end of period contents in January, February, March, and April 15 are the ECCLL for all major reservoir projects.

Notable changes in non-power constraints include a revision of last years fisheries requirements at Dworshak. The project began the Step I critical period 30.0 feet below full pool (i.e. an additional 20.0 feet lower than previous year's study) and met fisheries requirements until being drafted to empty at the end of the critical period. For the long-term study, Dworshak was usually operated to meet upper rule curve or minimum flow requirements.

Plant data for Monroe, Seven Mile, Cabinet Gorge, Canal, Nine Mile, Chief Joseph, and Thompson Falls were revised. However, Kootenay Canal, Chief Joseph, and Thompson Falls, were the only projects to show a significant increase in generation. The Willamette projects, Leaburg and Walterville, were modeled as hydro independents and therefore are no longer included as regulated projects.

Even though Dworshak, Walterville and Leaburg caused a decrease in the Step I critical period generation when compared to the previous years study, the net effect was an increase in critical period generation due to the plant data change at Thompson Falls, more storage at Chief Joseph, and the operation of Grand Coulee.

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 Columbia River Treaty Entity Agreement on Preparation of the 1998-99, 1999-00, and 2000-01 Assured Operating Plan and Determination of Downstream Power Benefit Studies.

5 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.

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

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

8 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.

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

10 Summary of End-of-Month Reservoir Storage Requirement from Columbia River Flood Regulation Studies, dated April 1973 and as updated March 1975.

11 BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 00-41, dated 4 November 1994.

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

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

TABLE 1
MICA PROJECT OPERATING CRITERIA
ASSURED OPERATING PLAN

Month	End of Previous Period Arrow Storage Content (ksfd)	------- Target Operation ------- Period Average Outflow (cfs)	End-of-Period Treaty Content 1/ (ksfd)	Minimum Outflow (cfs)	Minimum Treaty Storage Content 2/ (ksfd)
August 1-15	1 300 - FULL	-	3 456.2	10 000	0.0
	0 - 1 300	27 000			
August 16-31	3 400 - FULL	-	3 529.2	10 000	0.0
	1 100 - 3 400	24 000			
	0 - 1 100	27 000			
September	3 340 - FULL	-	3 529.2	10 000	0.0
	900 - 3 340	22 000			
	0 - 900	28 000			
October	3 295 - FULL	-	3 428.2	10 000	0.0
	500 - 3 295	25 000			
	0 - 500	29 000			
November	3 270 - FULL	-	3 176.2	13 000	0.0
	2 340 - 3 270	28 000			
	0 - 2 340	30 000			
December	3 390 - FULL	24 000		21 000	0.0
	2 500 - 3 390	28 000			
	0 - 2 500	30 000			
January	2 720 - FULL	25 000		15 000	356.2
	2 100 - 2 720	28 000			
	0 - 2 100	30 000			
February	1 284 - FULL	22 000		15 000	106.2
	1 090 - 1 284	26 000			
	0 - 1 090	28 000			
March	1 210 - FULL	21 000		15 000	0.0
	100 - 1 210	26 000			
	0 - 100	27 000			
April 1-15	0 - FULL	-	156.2	10 000	0.0
April 16-30	1 050 - FULL	-	106.2	10 000	0.0
	0 - 1 050	-	0.0		
May	190 - FULL	10 000		10 000	0.0
	0 - 190	21 000			
June	310 - FULL	10 000		10 000	0.0
	240 - 310	-	966.2		
	0 - 240	26 000			
July	2 000 - FULL	-	3 456.2	10 000	0.0
	1 160 - 2 000	19 000			
	0 - 1 160	25 000			

Notes:

1/ A maximum outflow of 34 000 cfs will apply if the target end-of-period storage content is less than 3529.2 ksfd in every month except April, May and June. For these periods, the maximum outflow is 31 000 cfs in April 1-15, 28 000 cfs in April 16-30, 30 000 cfs in May and 33 000 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 target flow.

TABLE 2

COMPARISON OF ASSURED OPERATING PLAN STUDY RESULTS

Study 00-41 provides Optimum Generation in Canada and in the United States.
Study 00-11 provides Optimum Generation in the United States only.

		Study No. 00-41	Study No. 00-11	Net Gain	Weight	Value
1.	Firm Energy Capability (Avg. MW)					
	U.S. System 1/	12183.0	12184.5	-1.5		
	Canada 2/, 3/	2800.1	2697.9	102.2		
	Total	14983.1	14882.4	100.7	3	302.1
2.	Dependable Peaking Capacity (MW)					
	U.S. System 4/	31273.0	31273.0	0.0		
	Canada 2/, 5/	5307.0	5310.0	-3.0		
	Total	36580.0	36583.0	-3.0	1	-3.0
3.	Average Annual Usable Secondary Energy (Avg. MW)					
	U.S. System 6/	3091.4	3071.9	19.5		
	Canada 2/, 7/	221.5	264.4	-42.9		
	Total	3312.9	3336.3	-23.4	2	-46.8
				Net Change in Value =		252.3

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

2/ Canadian system includes Mica, Revelstoke, 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

CRITICAL RULE CURVES
END OF MONTH CONTENTS (KSFD)
1999 - 00 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3529.2	3496.4	3398.1	3364.1	2641.1	2127.3	1890.6	1578.8	1070.4	513.1	427.5	2071.7	2814.9
1929-30	3276.4	3346.6	3104.2	2810.3	2256.8	1816.5	868.4	860.7	851.7	538.3	405.1	172.1	996.9	2800.7
1930-31	3100.4	3100.5	2800.8	2541.7	2079.0	1787.6	843.1	631.7	638.4	247.3	0.0	0.0	411.2	1639.6
1931-32	2122.2	2110.0	1611.8	816.4	348.3	39.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	3579.6	3579.6	3483.0	3351.9	3066.2	2635.2	1140.4	1203.5	1199.7	464.8	375.2	465.3	1872.9	3395.3
1929-30	3524.7	3417.1	3367.9	2851.6	2325.7	1820.1	695.2	786.5	890.4	471.1	381.2	468.1	1058.2	2142.5
1930-31	2466.7	2739.9	3073.2	2846.5	2315.5	1401.3	559.1	592.0	667.4	385.8	151.1	486.6	1342.1	1319.3
1931-32	1057.4	979.6	1124.0	1264.4	783.9	239.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	705.8	705.8	680.8	610.6	387.5	342.1	244.1	250.2	222.8	227.9	159.0	272.1	526.1	705.8
1929-30	635.7	657.8	676.1	559.6	342.6	241.8	122.4	128.0	50.0	36.5	59.8	13.0	170.0	387.6
1930-31	400.0	470.9	452.5	278.7	200.6	173.8	1.7	4.0	18.0	19.4	0.0	5.3	31.2	230.0
1931-32	183.0	108.9	170.0	60.0	53.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	7814.6	7814.6	7660.2	7360.6	6817.8	5618.4	3511.8	3344.3	3001.3	1763.1	1047.3	1164.9	4470.7	6916.0
1929-30	7436.8	7421.5	7148.2	6221.5	4925.1	3878.4	1686.0	1775.2	1792.1	1045.9	846.1	653.2	2225.1	5330.8
1930-31	5967.1	6311.3	6326.5	5666.9	4595.1	3362.7	1403.9	1227.7	1323.8	652.5	151.1	491.9	1784.5	3188.9
1931-32	3362.6	3198.5	2905.8	2140.8	1185.2	279.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 4

MICA
ASSURED AND VARIABLE REFILL CURVES
END OF MONTH CONTENTS (KSFD)
POWER DISCHARGE REQUIREMENTS (CFS)
1999 - 00 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	2101.6	2665.8	3269.1	3447.4	3512.7	3529.2	3529.2	3529.2	3529.2	3139.0	2752.2	2537.1	3142.4	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							3529.2	3529.2	3529.2	3529.2	3529.2	3308.7	3529.2	3529.2
1929-30							"	"	"	3140.6	2953.2	2696.1	3259.6	"
1930-31							"	"	"	3382.8	3125.9	2716.2	3334.8	"
1931-32							"	3053.3	2501.1	2173.5	2058.2	2041.0	3054.5	"
1932-33							3443.3	2904.1	2383.6	2060.9	1906.3	1880.2	2861.8	"
1933-34							2499.0	1994.2	1485.6	1187.3	1138.7	1553.4	3077.0	"
1934-35							3529.2	3529.2	3320.9	2948.2	2711.7	2490.2	3134.1	"
1935-36							"	"	3134.1	2735.2	2521.9	2439.3	3392.5	"
1936-37							"	"	3529.2	3529.2	3529.2	3322.4	3529.2	"
1937-38							"	3314.5	2768.0	2447.0	2297.2	2244.8	3135.0	"
1938-39							"	3529.2	3529.2	3295.2	3060.7	2739.7	3529.2	"
1939-40							"	"	3457.7	3049.5	2837.1	2532.6	3327.4	"
1940-41							"	"	3529.2	3529.2	3449.0	3096.5	3529.2	"
1941-42							"	"	"	3404.8	3166.2	2914.0	3463.6	"
1942-43							"	"	3190.6	2877.4	2793.7	2729.4	3297.2	"
1943-44							"	"	3529.2	3529.2	3529.2	3429.6	3529.2	"
1944-45							"	"	"	"	"	3351.0	"	"
1945-46							3039.0	2475.9	1963.8	1644.6	1522.2	1566.8	2962.8	"
1946-47							3457.4	2910.0	2384.7	2066.4	1944.1	2001.5	3119.7	"
1947-48							3117.9	2573.3	2075.5	1751.9	1616.3	1624.9	2918.9	"
1948-49							3529.2	3529.2	3529.2	3529.2	3529.2	3320.2	3529.2	"
1949-50							3458.3	2889.4	2368.2	2048.9	1912.6	1848.0	2730.2	"
1950-51							3449.5	2928.3	2439.2	2137.6	2028.3	1968.2	3091.7	"
1951-52							3529.2	3292.4	2778.2	2452.7	2306.5	2266.2	3239.0	"
1952-53							"	3529.2	3305.4	2971.9	2778.3	2589.9	3291.9	"
1953-54							3013.4	2479.5	1998.7	1693.1	1562.1	1540.3	2702.3	"
1954-55							3529.2	3529.2	3409.6	3049.8	2848.2	2684.0	3149.9	"
1955-56							3336.5	2786.0	2276.5	1959.9	1829.1	1865.2	3006.2	"
1956-57							3490.0	2947.3	2452.6	2148.0	2014.6	1952.1	3336.8	"
1957-58							3529.2	3013.4	2489.6	2173.5	2041.1	1988.9	3171.8	"
LIMITING RULE CURVE (KSFD)							497.0	313.0	147.3	14.6				

POWER DISCHARGE REQUIREMENTS (CFS)														
ASSURED REFILL CURVES							15000.0	25000.0	25000.0	33000.0	33000.0	35000.0	40000.0	44000.0
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF					--		3000.0	22000.0	22000.0	30000.0	30000.0	35000.0	35000.0	43000.0
95 MAF					--		3000.0	22000.0	22000.0	26000.0	26000.0	26000.0	33000.0	43200.0
110 MAF					--		3000.0	18000.0	18000.0	22000.0	22000.0	25000.0	25000.0	35000.0

TABLE 5

ARROW
ASSURED AND VARIABLE REFILL CURVES
END OF MONTH CONTENTS (KSFD)
POWER DISCHARGE REQUIREMENTS (CFS)
1999 - 00 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	307.7	1229.4	2304.3	2653.7	2722.9	2758.9	2803.3	1986.0	1138.3	1119.0	1213.3	2051.5	3235.2	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							3579.6	3579.6	2662.3	2409.8	2522.9	2532.4	3227.0	3579.6
1929-30							3319.1	2260.1	1148.4	930.5	1287.2	1923.9	3020.6	"
1930-31							3579.6	2690.7	1518.2	1287.6	1491.4	1758.7	3033.7	"
1931-32							312.4	280.8	147.8	20.8	0.0	0.0	2425.1	"
1932-33							"	"	"	"	"	34.9	2399.4	"
1933-34							"	"	"	"	"	512.3	2881.3	"
1934-35							"	"	"	"	"	452.0	2430.5	"
1935-36							"	"	"	"	"	561.3	2947.3	"
1936-37							3579.6	3579.6	2928.8	2637.0	2759.2	2718.7	3319.0	"
1937-38							312.4	280.8	147.8	20.8	0.0	489.6	2672.0	"
1938-39							3518.7	2479.4	1316.7	1086.7	1379.0	1843.8	3382.6	"
1939-40							3055.5	2001.8	980.9	876.8	1153.3	1628.3	3098.5	"
1940-41							3579.6	3374.0	2242.2	2128.9	2541.5	2813.5	3536.9	"
1941-42							1324.2	762.6	192.1	254.6	752.4	1579.3	3144.5	"
1942-43							312.4	280.8	147.8	20.8	184.5	1570.4	3130.1	"
1943-44							3579.6	3579.6	3511.6	3228.4	3351.9	3280.1	3579.6	"
1944-45							"	"	2626.5	2446.7	2584.6	2626.7	3451.4	"
1945-46							312.4	280.8	147.8	20.8	0.0	125.8	2649.7	"
1946-47							"	"	"	"	"	374.3	2656.4	"
1947-48							"	"	"	"	"	208.9	2653.3	"
1948-49							"	"	"	"	"	1298.7	3554.4	"
1949-50							"	"	"	"	"	150.2	2335.6	"
1950-51							"	"	"	"	"	494.9	2809.0	"
1951-52							"	"	"	"	"	552.7	2872.6	"
1952-53							"	"	"	"	"	583.7	2830.9	"
1953-54							"	"	"	"	"	0.0	2324.4	"
1954-55							"	"	"	"	"	"	2087.1	"
1955-56							"	"	"	"	"	192.7	2649.7	"
1956-57							"	"	"	"	"	33.5	2967.5	"
1957-58							"	"	"	"	"	0.0	2638.3	"
LIMITING RULE CURVE (KSFD)							312.4	280.8	147.8	20.8				

			JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (CFS)										
ASSURED REFILL CURVES			5000.0	35000.0	35000.0	38000.0	40000.0	48000.0	55000.0	65000.0
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)										
	80 MAF	--	5000.0	35000.0	40000.0	45000.0	45000.0	48000.0	48000.0	48000.0
	95 MAF	--	5000.0	7000.0	10000.0	10000.0	13000.0	13000.0	14000.0	42000.0
	110 MAF	--	5000.0	7000.0	10000.0	10000.0	12000.0	12000.0	13000.0	41000.0

TABLE 6

DUNCAN
ASSURED AND VARIABLE REFILL CURVES
END OF MONTH CONTENTS (KSFD)
POWER DISCHARGE REQUIREMENTS (CFS)
1999 - 00 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	77.2	148.1	214.4	245.1	262.6	273.8	284.0	282.0	252.7	244.9	234.1	341.7	531.6	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							542.9	522.0	482.0	468.1	457.5	472.0	604.5	705.8
1929-30							541.2	520.0	479.7	465.5	468.9	492.7	615.9	"
1930-31							485.8	465.8	429.0	420.0	415.8	441.6	604.5	"
1931-32							1.0	0.4	3.4	0.9	21.0	152.3	464.0	"
1932-33							"	"	"	"	0.0	0.0	329.6	"
1933-34							"	"	"	"	66.8	212.5	522.0	"
1934-35							142.8	133.5	129.9	130.1	146.5	241.2	481.8	"
1935-36							118.5	102.9	85.4	81.9	99.4	224.0	521.1	"
1936-37							490.8	469.8	431.5	417.5	407.8	434.0	586.7	"
1937-38							38.3	32.1	37.6	47.8	82.8	208.2	488.6	"
1938-39							337.8	323.2	288.6	278.7	284.9	353.4	587.3	"
1939-40							321.6	312.0	284.7	284.4	292.0	355.5	575.9	"
1940-41							403.2	390.8	359.5	360.4	375.2	432.9	599.6	"
1941-42							250.3	243.6	235.2	236.4	253.5	337.1	547.4	"
1942-43							169.1	158.4	162.1	166.9	200.2	319.2	521.5	"
1943-44							559.4	543.5	508.4	496.6	487.5	505.1	634.7	"
1944-45							457.3	442.8	412.1	401.9	394.6	423.8	587.5	"
1945-46							1.0	0.4	3.4	0.9	0.0	98.0	457.4	"
1946-47							"	"	"	"	"	141.1	470.1	"
1947-48							"	"	"	"	29.2	158.2	480.4	"
1948-49							224.1	210.2	210.4	212.3	236.7	332.5	582.3	"
1949-50							27.1	14.2	17.0	19.9	49.3	167.0	424.6	"
1950-51							1.0	0.4	3.4	0.9	0.0	132.6	455.6	"
1951-52							56.8	45.2	51.1	55.5	86.5	217.6	500.7	"
1952-53							55.5	44.4	49.5	54.6	83.6	195.9	467.0	"
1953-54							1.0	0.4	3.4	0.9	0.0	59.6	397.7	"
1954-55							"	"	"	"	26.3	145.5	401.4	"
1955-56							"	"	"	"	0.0	106.2	453.3	"
1956-57							7.7	"	"	"	35.0	159.7	517.6	"
1957-58							1.0	"	"	"	0.0	96.9	469.4	"
LIMITING RULE CURVE (KSFD)							1.0	0.4	3.4	0.9				
POWER DISCHARGE REQUIREMENTS (CFS)														
ASSURED REFILL CURVES							100.0	500.0	1500.0	1500.0	1700.0	1700.0	1700.0	1700.0
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF					--		100.0	500.0	1500.0	1500.0	2500.0	2500.0	2500.0	2500.0
95 MAF					--		100.0	300.0	300.0	500.0	500.0	800.0	800.0	800.0
110 MAF					--		100.0	300.0	300.0	500.0	500.0	800.0	800.0	800.0

TABLE 7

MICA
FLOOD CONTROL STORAGE RESERVATION CURVES
END OF MONTH CONTENTS (KSFD)
1999 - 00 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	3385.7	3347.2	3304.6	3304.6	3304.6	3369.1	3447.9	3529.2
1929-30	"	"	"	"	"	"	3352.6	3284.4	3208.7	3208.7	3208.7	3300.7	3413.2	"
1930-31	"	"	"	"	"	"	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	"
1931-32	"	"	"	"	"	"	3105.7	2813.6	2480.5	2480.5	2480.5	2781.5	3149.6	"
1932-33	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1933-34	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1934-35	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1935-36	"	"	"	"	"	"	3105.7	2813.6	"	"	"	"	"	"
1936-37	"	"	"	"	"	"	3330.6	3242.3	3144.5	3144.5	3144.5	3323.3	3398.4	"
1937-38	"	"	"	"	"	"	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1938-39	"	"	"	"	"	"	3193.8	2981.4	2746.8	2746.8	2746.8	2971.4	3246.0	"
1939-40	"	"	"	"	"	"	3274.3	3135.5	2976.4	2976.4	2976.4	3135.1	3329.1	"
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	"	"	"	"	"	"	3193.1	2980.2	2745.0	2745.0	2745.0	2970.0	3245.3	"
1945-46	"	"	"	"	"	"	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1947-48	"	"	"	"	"	"	3105.7	2813.6	"	"	"	"	"	"
1948-49	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1951-52	"	"	"	"	"	"	3105.7	2813.6	"	"	"	"	"	"
1952-53	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1955-56	"	"	"	"	"	"	3105.7	2813.6	"	"	"	2695.5	3172.7	"
1956-57	"	"	"	"	"	"	3101.7	2807.2	"	"	"	2781.5	3149.6	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	"	"	"

TABLE 8

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
END OF MONTH CONTENTS (KSFD)
1999 - 00 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	3075.5	3075.5	3075.5	3088.6	3111.3	3235.8	3579.6	3579.6
1929-30	"	"	"	"	"	"	2998.4	2928.3	2851.2	2870.1	2902.9	3082.8	"	"
1930-31	"	"	"	"	"	"	3075.5	3075.5	3075.5	3088.6	3111.3	3235.8	"	"
1931-32	"	"	"	"	"	"	2371.7	1735.5	1008.4	1016.1	1126.7	2224.6	"	"
1932-33	"	"	"	"	"	"	2363.6	1720.3	"	1008.4	1036.7	1761.8	3034.5	"
1933-34	"	"	"	"	"	"	"	"	"	"	1784.9	2327.4	3579.6	"
1934-35	"	"	"	"	"	"	"	"	"	"	1008.4	1725.8	3034.5	"
1935-36	"	"	"	"	"	"	2371.7	1735.5	"	1070.1	1373.5	2134.6	3579.6	"
1936-37	"	"	"	"	"	"	2940.8	2818.9	2684.2	2707.5	2755.8	3266.2	"	"
1937-38	"	"	"	"	"	"	2363.6	1720.3	1008.4	1083.0	1278.4	1831.2	3147.7	"
1938-39	"	"	"	"	"	"	2584.6	2141.3	1650.4	1719.8	1843.3	2661.3	3579.6	"
1939-40	"	"	"	"	"	"	2793.4	2538.5	2247.3	2287.3	2380.5	2913.5	"	"
1940-41	"	"	"	"	"	"	3075.5	3075.5	3075.5	3088.6	3111.3	3235.8	"	"
1941-42	"	"	"	"	"	"	2363.6	1720.3	1008.4	1065.0	1149.8	1934.1	"	"
1942-43	"	"	"	"	"	"	"	"	"	1111.3	1322.1	1440.4	2389.2	"
1943-44	"	"	"	"	"	"	3075.5	3075.5	3075.5	3088.6	3111.3	3235.8	3579.6	"
1944-45	"	"	"	"	"	"	2582.9	2138.1	1645.5	1672.6	1744.2	2368.9	3347.5	"
1945-46	"	"	"	"	"	"	2363.6	1720.3	1008.4	1072.7	1242.4	2201.5	3579.6	"
1946-47	"	"	"	"	"	"	"	"	"	1075.3	1360.7	2147.5	"	"
1947-48	"	"	"	"	"	"	2371.7	1735.5	"	1036.7	1183.3	2216.9	"	"
1948-49	"	"	"	"	"	"	2363.6	1720.3	"	1144.7	1376.1	2494.6	"	"
1949-50	"	"	"	"	"	"	"	"	"	1008.4	1008.4	1113.8	2232.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	1355.5	3337.9	"
1951-52	"	"	"	"	"	"	2371.7	1735.5	"	1070.1	1345.2	1792.6	3014.0	"
1952-53	"	"	"	"	"	"	2363.6	1720.3	"	1057.3	1173.0	1476.4	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	1134.4	1628.1	1898.1	"
1954-55	"	"	"	"	"	"	"	"	"	1075.3	1090.7	1653.8	3224.8	"
1955-56	"	"	"	"	"	"	2371.7	1735.5	"	1008.4	1216.7	1990.6	2993.4	"
1956-57	"	"	"	"	"	"	2363.6	1720.3	"	1077.8	1224.4	2651.4	3579.6	"
1957-58	"	"	"	"	"	"	"	"	"	1047.0	1191.0	2242.6	"	"

TABLE 9

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
END OF MONTH CONTENTS (KSFD)
1999 - 00 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	418.3	340.8	340.8	348.1	360.5	443.7	574.4	705.8
1929-30	"	"	"	"	"	"	408.4	322.1	322.1	329.8	342.8	430.3	567.6	"
1930-31	"	"	"	"	"	"	391.0	288.8	288.8	297.2	311.4	406.4	555.7	"
1931-32	"	"	"	"	"	"	277.2	65.5	65.5	80.9	109.1	281.3	609.7	"
1932-33	"	"	"	"	"	"	273.7	"	"	75.1	94.3	191.6	573.2	"
1933-34	"	"	"	"	"	"	"	"	"	65.5	127.0	339.6	605.2	"
1934-35	"	"	"	"	"	"	"	"	"	"	83.4	187.1	488.1	"
1935-36	"	"	"	"	"	"	277.2	"	"	71.2	119.3	351.7	705.8	"
1936-37	"	"	"	"	"	"	377.7	263.6	263.6	272.5	287.5	388.3	546.6	"
1937-38	"	"	"	"	"	"	293.0	102.3	102.3	113.1	119.2	245.3	551.9	"
1938-39	"	"	"	"	"	"	288.0	92.7	92.7	109.3	132.5	399.2	705.8	"
1939-40	"	"	"	"	"	"	303.2	115.4	115.4	127.2	150.8	410.6	"	"
1940-41	"	"	"	"	"	"	345.5	202.1	202.1	212.2	229.3	344.1	524.5	"
1941-42	"	"	"	"	"	"	328.5	169.9	169.9	179.0	201.5	326.3	501.6	"
1942-43	"	"	"	"	"	"	333.0	178.4	178.4	192.1	221.1	289.2	653.0	"
1943-44	"	"	"	"	"	"	416.4	334.7	334.7	342.1	354.7	439.4	572.2	"
1944-45	"	"	"	"	"	"	384.9	277.2	277.2	278.6	279.4	382.3	580.2	"
1945-46	"	"	"	"	"	"	273.7	65.5	65.5	75.7	95.6	322.3	647.5	"
1946-47	"	"	"	"	"	"	"	"	"	77.0	102.0	313.9	629.6	"
1947-48	"	"	"	"	"	"	277.2	"	"	65.5	65.5	300.5	705.8	"
1948-49	"	"	"	"	"	"	371.1	251.0	251.0	256.9	276.9	434.3	"	"
1949-50	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	183.9	525.2	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	285.1	534.2	"
1951-52	"	"	"	"	"	"	277.2	"	"	"	67.4	92.4	255.0	"
1952-53	"	"	"	"	"	"	273.7	"	"	71.9	84.7	234.5	522.7	"
1953-54	"	"	"	"	"	"	"	"	"	73.2	84.0	237.1	547.6	"
1954-55	"	"	"	"	"	"	"	"	"	71.9	80.9	154.5	488.7	"
1955-56	"	"	"	"	"	"	277.2	"	"	65.5	84.7	266.6	585.4	"
1956-57	"	"	"	"	"	"	273.7	"	"	74.5	89.8	376.1	655.8	"
1957-58	"	"	"	"	"	"	"	"	"	77.0	96.2	359.4	705.8	"

TABLE 10

COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS (KSFD)
1999 - 00 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7660.2	7390.9	6882.1	6529.4	6616.5	5797.2	4981.6	4502.9	4199.6	4930.3	6901.0	7814.6
1929-30	"	"	"	"	"	"	"	"	4930.3	4314.4	"	4802.7	6694.6	"
1930-31	"	"	"	"	"	"	"	"	4981.6	4502.9	"	4637.5	6707.7	"
1931-32	"	"	"	"	"	"	3842.6	3334.5	2652.3	2195.2	2079.2	2193.3	5943.6	"
1932-33	"	"	"	"	"	"	3756.7	3185.3	2534.8	2082.6	1906.3	1915.1	5590.8	"
1933-34	"	"	"	"	"	"	2812.4	2275.4	1636.8	1209.0	1205.5	2278.2	6480.3	"
1934-35	"	"	"	"	"	"	3984.4	3943.5	3598.6	3099.1	2858.2	3183.4	6046.4	"
1935-36	"	"	"	"	"	"	3960.1	3912.9	3367.3	2837.9	2621.3	3224.6	6610.8	"
1936-37	"	"	"	"	"	"	6616.5	5797.2	4981.6	4502.9	4199.6	4930.3	6909.2	"
1937-38	"	"	"	"	"	"	3879.9	3627.4	2953.4	2515.6	2380.0	2942.6	6295.6	"
1938-39	"	"	"	"	"	"	6616.5	5797.2	4981.6	4470.6	4199.6	4722.6	6909.2	"
1939-40	"	"	"	"	"	"	"	"	4691.3	4171.2	4139.6	4502.6	6772.5	"
1940-41	"	"	"	"	"	"	"	"	4981.6	4502.9	4199.6	4930.3	6909.2	"
1941-42	"	"	"	"	"	"	5103.7	4535.4	3956.5	3630.0	3738.7	4453.5	6818.5	"
1942-43	"	"	"	"	"	"	4010.7	3968.4	3500.5	3065.1	3136.9	4426.7	6794.0	"
1943-44	"	"	"	"	"	"	6616.5	5797.2	4981.6	4502.9	4199.6	4930.3	6909.2	"
1944-45	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1945-46	"	"	"	"	"	"	3352.4	2757.1	2115.0	1666.3	1522.2	1790.6	6069.9	"
1946-47	"	"	"	"	"	"	3770.8	3191.2	2535.9	2088.1	1944.1	2516.9	6246.2	"
1947-48	"	"	"	"	"	"	3431.3	2854.5	2226.7	1773.6	1645.5	1992.0	6052.6	"
1948-49	"	"	"	"	"	"	4065.7	4020.2	3887.4	3372.1	2986.3	4168.3	6909.2	"
1949-50	"	"	"	"	"	"	3797.8	3184.4	2533.0	2089.6	1961.9	2165.2	5490.4	"
1950-51	"	"	"	"	"	"	3762.9	3209.5	2590.4	2159.3	2028.3	2595.7	6356.3	"
1951-52	"	"	"	"	"	"	3898.4	3618.4	2977.1	2529.0	2393.0	3036.5	6515.7	"
1952-53	"	"	"	"	"	"	3897.1	3854.4	3502.7	3047.3	2835.8	3316.7	6440.3	"
1953-54	"	"	"	"	"	"	3326.8	2760.7	2149.9	1714.8	1562.1	1599.9	5424.4	"
1954-55	"	"	"	"	"	"	3842.6	3810.4	3560.8	3071.5	2778.5	2682.6	5630.9	"
1955-56	"	"	"	"	"	"	3419.1	3067.2	2427.7	1981.6	1829.1	2164.1	6109.2	"
1956-57	"	"	"	"	"	"	3810.1	3228.5	2603.8	2169.7	2049.6	2145.3	6627.5	"
1957-58	"	"	"	"	"	"	3842.6	3294.6	2640.8	2195.2	2041.1	2085.8	6250.1	"

TABLE 11

COMPARISON OF RECENT ASSURED OPERATING PLAN STUDIES

	1995-96	1996-97	1997-98	1998-99	1999-00
MICA TARGET OPERATION (ksfd or cfs)					
- AUG 1	3456.2	3456.2	3456.2	3456.2	3456.2
- AUG 2	FULL	FULL	FULL	FULL	FULL
- SEP	FULL	FULL	FULL	FULL	FULL
- OCT	3428.4	14000.0	15000.0	11000.0	3428.2
- NOV	22000.0	19000.0	19000.0	3256.2	3176.2
- DEC	24000.0	23000.0	23000.0	2676.2	24000.0
- JAN	27000.0	24000.0	24000.0	24000.0	25000.0
- FEB	25000.0	20000.0	22000.0	22000.0	22000.0
- MAR	25000.0	19000.0	19000.0	22000.0	21000.0
- APR 1	24000.0	156.2	106.2	86.2	156.2
- APR 2	14000.0	0.0	0.0	56.2	106.2
- MAY	10000.0	10000.0	10000.0	10000.0	10000.0
- JUN	10000.0	10000.0	10000.0	10000.0	10000.0
- JUL	3356.2	3356.2	3356.2	3406.2	3456.2
CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)					
NOV 1928 (-41)	1272.7	1481.7	922.2	638.8	996.8
APR 1929 (-41)	7801.6	7708.8	7727.7	7083.9	6767.3
JUL 1929 (-41)	1140.5	1028.6	951.2	808.8	898.6
AUG 1929 (-41)	1060.4	483.2	864.3	181.0	393.1
NOV 1928 (-11)	1275.3	1483.6	923.3	642.0	998.4
JUL 1929 (-11)	1142.8	1036.6	955.2	830.8	905.0
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
- U.S. Firm Energy	-4.4	-2.0	-0.9	-5.1	-1.5
- U.S. Dependable Capacity	2.0	3.0	-4.0	27.0	0.0
- U.S. Secondary Energy	2.9	1.2	13.9	18.9	19.5
- BCH Firm Energy	56.0	36.0	46.7	26.7	102.2
- BCH Dependable Capacity	16.0	-10.0	19.0	18.0	-3.0
- BCH Secondary Energy	-38.3	-36.9	-43.5	-18.5	-42.9
HYDROREG SECONDARY LOAD (MW)					
- AUG 1	11475	14510	14547	15568	16063
- AUG 2	11475	14396	14416	15422	15907
- SEP	11466	14147	13878	14883	15452
- OCT	12021	14616	14674	15594	16051
- NOV	12272	15412	15411	16347	16628
- DEC	12443	15951	15835	16578	16938
- JAN	12633	16000	15832	16598	16913
- FEB	12641	15884	15841	16638	16839
- MAR	11909	15031	15160	15942	16087
- APR 1	11817	13840	14438	15523	16025
- APR 2	11573	13267	14391	15513	15200
- MAY	8114	10734	10297	10960	9560
- JUN	11236	14260	11748	11120	11029
- JUL	11590	14648	14843	15529	16175

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1999-00

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS
FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1999-00

Preface to the 1999-00 DDPB

The Determination of Downstream Power Benefits (DDPB) for the Assured Operating Plan (AOP) for operating year 1999-00 presents both a U.S. and Canadian determination of the dependable capacity component of the Canadian Entitlement. Two determinations of the Capacity Entitlement are presented because the Entities have been unable to agree on a single interpretation of the definition of "critical stream flow period" in Article I, Paragraph 1.(d), of the Treaty.

Negotiators for the U.S. and Canadian Entities have tentatively resolved the determination of the Capacity Entitlement by agreeing to a set of principles which, if implemented, will render moot the two sets of values for the Capacity Entitlement presented in this Preface. In order to implement the principles, the Entities are preparing definitive agreements based on the principles and expect that these agreements will be authorized by an Exchange of Notes between the U.S. and Canadian Governments in 1995.

The Memorandum of Negotiators' Agreement on "Statement of Principles for Delivery and Disposition of the Canadian Entitlement" specifies that the U.S. will deliver under a "capacity buydown" provision applicable to the period from 1998 to 2024 the lesser of (1) 950 MW or (2) the amount of Capacity Entitlement computed according to the Treaty, excluding provisions related to the Capacity Credit Limit, with a prorata share for the period 1 April 1998 through 31 March 2003. In consideration, the U.S. will purchase the capacity obligation in excess of the amounts required to be delivered for U.S. $180 million. The Agreement also specifies that the Capacity Entitlement will be calculated and displayed for AOP/DDPB purposes on a "without prejudice" basis, using both the U.S. ("Discretionary Draft for Power") and Canadian ("Draft for Power") determinations. Each Entity also reserves the right to put forward its view of the proper interpretation of "critical stream flow period" if and when the Capacity Entitlement using either interpretation falls below 950 MW for reasons other than the Capacity Credit Limit.

In order to proceed with completion of the 1999-00 AOP/DDPB prior to the Exchange of Notes required between the U.S. and Canadian Federal governments to approve the capacity buydown provision, the Entities have agreed to prepare this document without reference to the capacity buydown provision and consequently two values for the Capacity Entitlement are displayed throughout the document reflecting the two interpretations of "critical stream flow period."

The two interpretations of critical stream flow period are described as follows:

<u>Discretionary Draft for Power</u> - Under this interpretation, the Step III critical stream flow period is deemed to start when an initial draft, in excess of drafts necessary to meet flood control requirements and/or non-power requirements is required from reservoir storage to meet firm load requirements. Using this interpretation, the Step III critical period starts 1 November 1936. The Step III critical period ends on 30 April 1937, for a duration of 6 months.

Draft for Power - Under this interpretation, the Step III critical stream flow period is deemed to start when an initial draft, in excess of drafts necessary to meet flood control requirements, is required from reservoir storage to meet firm load requirements. Using this interpretation, the Step III critical period begins 1 October 1936. The Step III critical period ends on 30 April 1937, for a duration of 7 months.

The only variation between the U.S. and Canadian DDPB computations is the determination of the start of the Step III critical stream flow period which primarily affects the determination of the Capacity Entitlement. The Capacity Entitlement resulting from the different critical stream flow period definitions is shown below for the joint optimum studies:

1999-00 DDPB
Joint Optimum Studies

Critical Stream Flow Period Definition	Proposed by	Capacity Entitlement
Discretionary Draft for Power	U.S.	1276.7 MW
Draft for Power	Canada	1461.9 MW
Difference	⇒	185.2 MW

The Entities have agreed to compute Energy Entitlement based on the Discretionary Draft for Power interpretation (the difference in Energy Entitlement resulting from the different critical stream flow period definitions is insignificant).

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DETERMINATION OF DOWNSTREAM POWER BENEFITS
FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1999-00

November 1994

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 those downstream power benefit computations developed from the 1999-00 Assured Operating Plan (AOP).

The procedures followed in the benefit studies are those provided in Annex A, Paragraph 7, and Annex B of the Treaty; in Articles VIII, IX, and X of the Protocol; in the Entity Agreement on Resolution of Assured Operating Plan and Determination of Downstream Power Benefit Issues for the 1998-99, 1999-00, and 2000-01 AOP/DDPB, signed November 1994, in 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); and in the document, "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated December 1991.

The Canadian Entitlement Benefits were computed from the following studies:

Step I -- operation of the total United States of America planned hydro and thermal system with 15-1/2 million acre-feet (maf) of Canadian storage operated for optimum power generation in both countries.

Step II -- operation of the United States base hydro and thermal system with 15-1/2 maf of Canadian storage operated for optimum power generation in both countries.

Step III -- operation of the United States base hydro and thermal system operated for optimum power generation in the United States.

As part of the determination of downstream power benefits for the operating year 1999-00, separate determinations were carried out relating to the limit of year-to-year change in benefits attributable to the operation of Canadian Treaty storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America (joint optimum).

As required by the Canadian Entitlement Purchase Agreement, the decrease in downstream power benefits due to the operation of Canadian Treaty storage for joint optimum power generation, instead of operation of Canadian Treaty storage for optimum power generation in the United States of America only (US optimum), was separately determined.

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):

Dependable Capacity		
- Discretionary Draft for Power interpretation	=	1276.7 MW
- Draft for Power interpretation	=	1461.9 MW
Average Annual Energy	=	559.5 aMW

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 1999-00 operating year are based on the formula X - (Y - Z).

The quantities X, Y, and Z, expressed in terms of entitlement to downstream power benefits, are computed as follows:

X is one half of the downstream power benefits derived from the previous year's Step II joint optimum and Step III US optimum AOP studies.

Y is one half of the downstream power benefits derived from the difference between the previous year's Step II US optimum and Step III US optimum AOP studies.

Z is one half of the downstream power benefits derived from the difference between the present year's Step II US optimum with 15 maf of Canadian storage and Step III US optimum AOP studies.

The purpose of this formula is to set a lower limit on the Canadian Entitlement by accumulating the annual reductions resulting from reoperation of Canadian storage as well as the reductions caused by year-to-year changes in data and by removal of 0.5 maf storage.

The quantities X and Y were computed in the 1998-99 DDPB. The quantity Z, which is computed from one-half of the downstream power benefits determined for 15 maf of Canadian Treaty storage operated for optimum power generation in the United States of America, is computed in Table 5.

The computation of the formula X - (Y - Z) is as follows:

Dependable Capacity

- Discretionary Draft for Power interpretation
  = 1324.7 - (1325.1 - 1254.0) = 1253.6 MW
- Draft for Power interpretation
  = 1514.7 - (1515.1 - 1439.2) = 1438.8 MW

Average Annual Energy = 562.7 - (566.8 - 557.4) = 553.3 aMW

The computed Canadian Entitlement exceeds these amounts.

4. Effect on Sale of Canadian Entitlement

The Canadian Entitlement to downstream power benefits was sold to the United States of America under the Canadian Entitlement Purchase Agreement (CEPA) dated 13 August 1964, for a period of thirty years following the completion of each Canadian storage project. The purchase of the Canadian Entitlement by the United States under CEPA expires 31 March 1998 for Duncan, 31 March 1999 for Arrow, and 31 March 2003 for Mica.

The studies developed for this sale included the assumption of operation of Treaty storage only for optimum power generation downstream in the United States of America. The Canadian Entitlement determined from the 1999-00 Assured Operating Plan for this condition would have been:

Dependable Capacity		
- Discretionary Draft for Power interpretation	=	1276.5 MW
- Draft for Power interpretation	=	1461.7 MW
Average Annual Usable Energy	=	560.3 aMW

Because the 1999-00 Assured Operating Plan was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America, Section 7 of the Agreement requires that "any reduction in the Canadian Entitlement resulting from action taken pursuant to Paragraph 7 of Annex A of the Treaty shall be determined in accordance with Subsection (3) of Section 6 of this Agreement". A comparison of the Canadian Entitlement for optimum power in Canada and the United States with the Canadian Entitlement to downstream power benefits shown above indicates a <u>decrease</u> in Canadian Entitlement of 0.8 aMW of average annual usable energy and an <u>increase</u> in dependable capacity of 0.2 MW (The capacity differentials are same under either critical stream flow period interpretation).

Since the sale of the downstream power benefits attributable to Duncan and Arrow expires 31 March 1998 and 31 March 1999 respectively, the United States Entity is entitled to that portion of the decrease in Canadian Entitlement attributed to Mica. The decrease of the Canadian Entitlement attributed to Mica is computed by multiplying the decrease in Canadian Entitlement by the ratio of Mica storage (7.0 maf) to the whole of Canadian storage (15.5 maf). The value is computed to be:

Capacity Payment = Not applicable
Energy Payment = 0.8 aMW * (7.0 maf/15.5 maf) = 0.4 aMW

Accordingly, the Entities are agreed that the United States Entity is entitled to receive 0.4 aMW of energy, and 0 MW of dependable capacity, during the period 1 April 1999 through 31 March 2000, from B.C. Hydro & Power Authority, in accordance with Sections 7 and 10 of CEPA.

5. Canadian Entitlement Return

The sale of the Canadian Entitlement attributable to Duncan storage and Arrow storage terminates on 31 March 1998 and 31 March 1999 respectively, under Section 2. (1)(a) of CEPA. Under Section 2. (3) of this agreement, the percentage of the downstream power benefits allocable to each Canadian storage project is the percentage of the total of the Canadian storages provided by that storage as set out in Article II of the Treaty.

The storage volume in Duncan is 1.4 maf, in Arrow 7.1 maf, and the whole of Canadian storage 15.5 maf. The obligation of the United States to deliver Canadian Entitlement to Canada for operating year 1999-00 beginning 1 August 1999 and ending 31 July 2000, based on the joint optimum power studies, for benefits attributable to Duncan and Arrow is computed to be:

a) Energy Entitlement

Average Annual Energy = 559.5 aMW * (8.5 maf/15.5 maf) = 306.8 aMW

b) Capacity Entitlement

Dependable Capacity
- Discretionary Draft for Power interpretation
  = 1276.7 MW * (8.5 maf/15.5 maf) = 700.1 MW
- Draft for Power interpretation
  = 1461.9 MW * (8.5 maf/15.5 maf) = 801.7 MW

6. Summary of Canadian Entitlement Computations

The following Tables and Chart summarize the study results. Table 4 has been formatted to present study results from both critical streamflow period definitions.

Table 1. Determination of Firm Hydro Loads for Step I Studies:

This table shows the loads and resources used in the Step I studies and the computation of the residual hydro load for the Step I study. This table has been reorganized to more closely follow the definition of Step I loads and resources as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Table 1 was also split into tables 1A and 1B. 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 existing and scheduled thermal energy capability including thermal imports after allowance for energy reserves, minimum thermal generation, and reductions for the thermal resources used outside the PNW Area. The computation of Step I thermal installations has been moved to Table 1.

Table 3. Determination of Loads for 1999-00 Step II and 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 does the Pacific Northwest (PNW) area load. The PNW area firm loads on this table were based on the BPA September 1993 load forecast. The Grand Coulee pumping load is also 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 1999-00 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. Table 4 was split into Tables 4A and 4B. Table 4A summarizes results of Step I and Step II power regulation studies. Table 4B summarizes the Step III power regulation study for both the Discretionary Draft for Power and the Draft for Power interpretations of critical stream flow period interpretations.

Table 5. Computation of Canadian Entitlement For 1999-00 Assured Operating Plan:

A. 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 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage

The essential elements used in the computation of the Canadian Entitlement to downstream power benefits, the minimum permitted downstream power benefits, and the reduction in downstream power benefits attributable to the operation of Canadian Treaty storage for optimum power generation in the United States of America only are shown on this table. Table 5 also displays the Capacity Entitlement for both interpretations of critical stream flow period (i.e., Discretionary Draft for Power, and Draft for Power).

Chart 1. 1999-00 Determination of Downstream Power Benefits 30-Year Monthly Hydro Generation:

This chart shows duration curves of the hydro generation from the Step II and III studies and graphically illustrates the change in the portion of secondary energy that is usable for thermal displacement due to operation of Treaty storage. Secondary energy is the energy capability each month which 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 used to meet PNW area 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 remainder after thermal displacement.

7. Summary of Changes From Previous Year

Data from the five most recent Determination of Downstream Power Benefits are summarized in Tables 6 and 7. Firm energy shifting was not included in the 1996-97, 1997-98, 1998-99, and the 1999-00 operating plan studies. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Resources

Loads for the 1999-00 AOP were based on the 1993 Whitebook medium case forecast developed by BPA in September 1993. The Pacific Northwest Area firm energy load increased by 338.2 annual aMW. The total exports, not including firm surplus energy, increased by 127.4 aMW. The firm surplus energy increased by 173.5 aMW. The increase in exports is mainly due to the increased Canadian Entitlement Return.

The estimated increase in PNW area load for return of the Canadian Entitlement and the computed Canadian Entitlement attributed to Duncan and Arrow for the period 1 August 1999 through 31 July 2000 is shown below for the joint optimum studies:

	Energy Entitlement (aMW)		Capacity Entitlement (MW)		
	Estimated	Computed	Estimated	Computed 1/	
				A	B
1 August 1999 to 31 July 2000	306.0	306.8	726.0	700.1	801.7

1/ (A) refers to Discretionary Draft for Power interpretation, (B) refers to Draft for Power interpretation

Iterative studies were not performed because updating the Canadian Entitlement estimates would not materially affect the results of the studies.

The total energy capability of the thermal installations increased by 551.6 aMW. Major thermal resource changes included:

1) Decrease of 61 aMW due to the removal of the Small Thermal resources,
2) Combustion Turbine resource increases of 67.0 aMW due to facilities upgrade at Beaver and other small changes,
3) Co-generation increased 664.0 aMW due the addition of four new projects: Coyote Springs, PP&L Miscellaneous, Scott Paper, and Wauna,
4) Centralia large thermal generation decreased by 36 aMW,
5) Thermal Non-Utility Generation (NUGs) decreased by 16.1 aMW,
6) Decrease of 67.0 aMW in PP&L (WYM) to PP&L Thermal import.

(b) Operating Procedures

The 1990 level modified base flows were again used, with no additional depletion to the 2000 level, based on the recommendation of the Columbia River Water Management Group. Coulee pumping adjustments and return flow, however, were included.

The spill and bypass assumptions for the 1999-00 DDPB studies are the same as in the 1998-99 DDPB studies, except that, for operating year 1999-00, it was assumed that fish bypass installations were implemented at Priest Rapids, Rocky Reach and Rock Island.

The Entities completed Step II and III refill studies and incorporated the resulting Power Discharge Requirements (PDRs) in the 1999-00 DDPB. New Energy Content Curve Lower Limits (ECCLL) were developed for the Step II system based on 1937 water conditions. These studies are consistent with PNCA procedures, which includes starting the system full 1 August 1936 and adjusting the load until the system is empty 30 April 1937. The end of period contents in January, February, March, and April 15 are the ECCLL for all major reservoir projects. Since the Step III study itself is an "ECCLL type" study, the ECCLL are simply the end storages from the study.

Plant data for Monroe, 7-Mile, Cabinet Gorge, Canal, Nine Mile, Chief Joseph, and Thompson Falls were revised. However, Canal, Chief Joseph, and Thompson Falls were the only projects to show a significant increase in generation.

(c) Step III Critical Stream Flow Period

As discussed in the preface, the Entities are unable to agree on a single interpretation of the definition of "critical stream flow period" as described in Treaty, Article I, Paragraph 1.(d) and as applied to the Step III system. Consequently, two methods are used for determining the Step III "critical stream flow period." Under both interpretations, the critical stream flow period would occur in the 1936/37 water year, and the ending period would be the same. Only the starting period for the critical stream flow period would be different under the two interpretations.

Under the Discretionary Draft for Power interpretation, the Step III study had a critical stream flow period of 6 months, 1 November 1936 through 30 April 1937 . Under the Draft for Power interpretation, the Step III study had a critical stream flow period of 7 months, 1 October 1936 through 30 April 1937. The Step III critical stream flow period in the previous AOP ended 15 April 1937. The end of the Step III critical stream flow period changed because of a decrease in residual hydro load in the first half of April and an increase in residual hydro load in the second half of April resulting from changes in thermal resource availability and maintenance schedules.

(d) Downstream Power Benefits Computation

Under the Discretionary Draft for Power interpretation, the Capacity Entitlement decreased from 1324.7 MW in the 1998-99 DDPB to 1276.7 MW in the 1999-00 DDPB for a loss of 48.0 MW. The primary reason for the Capacity Entitlement decrease is the 96.4 MW increase in the Step III critical period average generation which in turn resulted from the second half of April now being included in the 1999-00 Step III critical period. The Step II average critical period generation increased by 16.3 MW compared to the 1999-00 DDPB due to updated plant data for Thompson Falls and Chief Joseph. Therefore, the difference between the Step II and Step III average critical period generation decreased by 80.1 aMW resulting in a decrease in the Capacity Entitlement.

Under the Draft for Power interpretation, the Capacity Entitlement decreased from 1514.7 MW in the 1998-99 DDPB to 1461.9 MW in the 1999-00 DDPB for a loss of 52.8 MW. Relative to the Capacity Entitlement under the Discretionary Draft for Power interpretation, the Capacity Entitlement under the Draft for Power interpretation increased by 185.2 MW because the start of the Step III critical stream flow period changed from November to October which caused the average rate of generation during the Step III critical stream flow period to decrease by 278.8 aMW.

The Canadian Energy Entitlement decreased from 562.7 aMW in the 1998-99 DDPB to 559.5 aMW in the 1999-00 DDPB, a decrease of 3.2 aMW. New data for Thompson Falls and Chief Joseph increased the Energy Entitlement while a larger thermal displacement market decreased the Energy Entitlement. The net effect of all changes was the small decrease in the Energy Entitlement.

TABLE 1A

1999-00 ASSURED OPERATING PLAN
DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES 1/

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July	Annual Average	CP Ave 3/ (42 Mon)
Step I Energy Loads (aMW)																
1. PNW Area Load	19363	19285	18708	19495	21603	23244	24230	22832	21567	20288	20386	19576	19450	19542	20817.8	20942.1
2. Annual Load Shape (Percent)	93.01	92.64	89.87	93.65	103.77	111.65	116.39	109.68	103.60	97.45	97.93	94.03	93.43	93.87	100.0	100.6
3. Firm Exports	1459	1459	1472	1151	1099	1097	1071	1039	1076	1072	1072	1018	1394	1476	1202.7	1195.9
4. Minus Plant Sales	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2	-95.3
5. Firm Surplus	0	0	0	0	0	0	0	0	0	0	0	4237	4237	0	708.1	607.2
6. Hydro Maintenance	32	27	9	9	4	0	0	0	5	8	8	20	15	51	12.7	11.4
Load Reduction Resources																
7. Hydro Independents (1929)	-1242	-1183	-1043	-1109	-1143	-1045	-1080	-798	-940	-1255	-1309	-1774	-1579	-1256	-1190.8	-1044.7
8. Other Coord Hydro (1929)	-539	-465	-567	-975	-980	-965	-1082	-730	-812	-580	-648	-680	-1312	-877	-841.9	-863.0
9. Non-Thermal Purpa/Nugs	-187	-187	-178	-163	-162	-157	-161	-167	-173	-189	-189	-188	-195	-197	-176.4	-174.7
10. Miscellaneous	-58	-58	-61	-65	-71	-75	-75	-72	-70	-65	-65	-62	-61	-59	-66.1	-66.7
11. Non-thermal firm imports	-20	-20	-15	-21	-36	-47	-60	-69	-61	-29	-29	-28	-38	-26	-37.3	-37.9
12. Seasonal Exchange Imports	0	0	0	0	-304	-353	-359	-354	-60	-6	-6	0	0	0	-118.2	-133.8
13. Total Step I Study Loads (1929)	18706	18756	18223	18220	19908	21597	22382	21579	20430	19142	19118	22079	21840	18552	20216.4	20340.4
Step I Thermal Resources (aMW)																
14. Large Thermal	4552	4552	4552	4552	4552	4552	4552	4552	4365	4018	3301	2111	3906	4552	4202.3	4252.2
15. Small Thermal	42	42	42	42	48	48	48	48	42	42	42	42	42	42	44.0	44.3
16. Combustion Turbines	1877	1793	1763	1999	1942	1995	1999	1999	1827	1796	1137	1404	1653	1901	1814.9	1834.1
17. Cogeneration	1490	1490	1465	1483	1471	1488	1489	1442	1487	1481	1390	925	1395	1490	1421.3	1428.7
18. Purpa/Nugs - Thermal	281	281	267	244	243	236	241	250	260	283	283	282	293	295	264.6	262.1
19. Renewables	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51.0	51.0
20. Thermal Firm Imports	1261	1189	1122	1162	1690	1881	1820	1749	1259	1060	998	721	1184	1306	1343.2	1375.6
21. Minus Seas Exch Imports	0	0	0	0	-304	-353	-359	-354	-60	-6	-6	0	0	0	-118.2	-133.8
22. Minus Plant Sales	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2	-95.3
23. Total Step I Thermal Installations	9452	9296	9160	9431	9591	9796	9739	9635	9129	8623	7094	5496	8453	9535	8929.0	9018.9
Regulated Hydro Load (1929) 2/	9254	9460	9063	8789	10317	11801	12643	11944	11301	10519	12024	16583	13387	9017	11287.5	11321.5

Notes:

1/ Step I Loads and Resources for the U.S. Optimum Study (00-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements.

2/ Regulated hydro load for U.S. projects located upstream of Bonneville Dam, Line 13 - Line 23.

3/ The Step I critical period begins 1 September 1928 and ends 29 February 1932.

TABLE 1B

1999-00 ASSURED OPERATING PLAN
DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES 1/

		Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
Step I Peak Loads (MW)															
1.	PNW Area Load	24095	24050	23822	26765	29107	31680	32979	31493	29415	27790	27872	25987	24672	24378
2.	Load Factor (Percent)	80.19	80.19	78.53	72.84	74.22	73.37	73.47	72.50	73.32	72.97	72.97	75.33	78.83	80.16
3.	Firm Exports	3367	3367	3376	2831	1840	1814	1815	1809	1792	1786	1786	1922	3364	3366
4.	Minus Plant Sales	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-45	-116	-116
5.	Firm Surplus	0	0	0	0	0	0	0	0	0	0	0	5560	5312	0
6.	Hydro Maintenance	4629	4067	3788	3209	2934	2037	1561	2295	2646	2751	2483	2360	2204	3725
	Load Reduction Resources														
7.	Hydro Independents (1937)	-1918	-1900	-1820	-1775	-1721	-1699	-1634	-1754	-1836	-1956	-1982	-2159	-2183	-2018
8.	Other Coord Hydro (1937)	-2640	-2566	-2660	-2615	-2479	-2463	-2353	-2179	-2075	-2070	-2013	-2166	-2541	-2623
9.	Non-Thermal Purpa/Nugs	-195	-195	-187	-171	-169	-165	-169	-174	-183	-197	-197	-207	-203	-205
10.	Miscellaneous	-38	-38	-41	-45	-351	-355	-355	-352	-350	-48	-48	-45	-44	-39
11.	Non-thermal firm imports	-147	-147	-147	-147	-134	-148	-170	-194	-224	-147	-147	-147	-147	-147
12.	Minus Seasonal Exchange	0	0	0	0	-721	-721	-721	-721	-196	-12	-12	0	0	0
13.	Total Step I Study Loads (1937)	27037	26522	26015	27936	28190	29864	30837	30107	28873	27781	27626	31060	30318	26321
Step I Thermal Resources (MW)															
14.	Large Thermal	5286	5286	5286	5286	5286	5286	5286	5286	5021	4809	3813	2528	4270	5286
15.	Small Thermal	55	55	55	55	144	144	144	144	55	55	55	55	55	55
16.	Combustion Turbines	2320	2142	2258	2530	2510	2515	2547	2542	2111	2100	2061	2125	2054	2298
17.	Cogeneration	1577	1577	1567	1570	1573	1575	1576	1575	1574	1583	1583	1035	1198	1577
18.	Purpa/Nugs - Thermal	293	293	281	256	254	247	253	261	275	296	296	310	305	307
19.	Renewables	52	52	52	52	52	52	52	52	52	52	52	52	52	52
20.	Thermal Firm Imports	1472	1473	1348	1399	2092	2365	2320	2274	1430	1260	1243	1294	1625	1469
21.	Minus Seas Exch Imports	0	0	0	0	-721	-721	-721	-721	-196	-12	-12	0	0	0
22.	Minus Plant Sales	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-45	-116	-116
23.	Total Step I Thermal Installations	10939	10762	10731	11032	11074	11347	11341	11297	10206	10027	8975	7354	9443	10928
Regulated Hydro Load (1937) 2/		16098	15760	15284	16904	17116	18517	19496	18810	18667	17754	18651	23706	20875	15393

Notes:

1/ Step I Loads and Resources for the U.S. Optimum study (00-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements.

2/ Regulated hydro load for U.S. projects located upstream of Bonneville Dam, Line 13 - Line 23.

TABLE 2

1999-00 ASSURED OPERATING PLAN
DETERMINATION OF THERMAL DISPLACEMENT MARKET

(Energy in Average MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July	Annual Average
TOTAL STEP I THERMAL INSTALLATIONS															
1. From Table 1A, line 23	9452	9296	9160	9431	9591	9796	9739	9635	9129	8623	7094	5496	8453	9535	8929.0
SYSTEM SALES															
2. Total Exports	1459	1459	1472	1151	1099	1097	1071	1039	1076	1072	1072	1018	1394	1476	1202.7
3. Minus Can Entitlement (out of the PNWA)	-308	-308	-308	-308	-308	-308	-308	-308	-308	-308	-308	-308	-308	-308	-308.0
4. Minus Plant Sales Exports	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2
5. Minus Seasonal Exch. Exports	-342	-342	-351	-36	0	0	0	0	0	0	0	0	-312	-356	-116.8
6. Added Firm Surplus Sales	0	0	0	0	0	0	0	0	0	0	0	4237	4237	0	708.1
7. Total System Sales	707	707	711	705	689	687	661	629	666	662	662	4907	4940	710	1391.8
8. Uniform Avg. Annual System Sales	1392	1392	1392	1392	1392	1392	1392	1392	1392	1392	1392	1392	1392	1392	1391.8
MINIMUM THERMAL GENERATION															
9. Large Thermal Min. Generation	374	374	683	683	683	683	683	683	594	264	258	282	374	374	528.8
10. Cogen & Small Thermal Min. Generation	445	445	448	451	454	455	455	454	453	452	452	216	447	445	430.9
11. NUGS Thermal Min. Generation	93	93	88	80	80	78	80	82	86	93	93	93	97	97	87.3
12. Total Minimum Generation	912	912	1219	1214	1217	1216	1218	1219	1133	809	803	591	918	916	1046.9
13. THERMAL DISPLACEMENT MARKET	7148	6992	6549	6825	6982	7188	7129	7024	6604	6422	4899	3513	6143	7227	6490.2

Notes:

Line 4	Plant sales include Longview Fibre and 15 percent of Boardman.
Line 5	Seasonal exchanges with extraregional utilities.
Line 7	System Sales are total exports excluding plant sales, seasonal exchanges, and the Canadian Entitlement. The sum of Lines 2 through 6.
Line 8	Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.
Line 9	Large Thermal minimum generation includes Centralia, Jim Bridger, and Valmy.
Line 10	Cogen & Small Thermal Minimum Generation Includes Spokane Muni Solid Waste, Tacoma Steam Plant , and four EWEB cogen plants.
Line 11	60% of the total NUGS is thermal. Non-displaceable NUGS generation is 1/3 of the thermal NUGS.
Line 12	Total Minimum Thermal Generation, the sum of Lines 9 through 11.
Line 13	PNW Area Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNW Area firm loads. Line 1 - 8 - 12

TABLE 3
1999-00 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR
STEP II AND STEP III STUDIES

LOAD OF THE PACIFIC NORTHWEST AREA						STEP II STUDY		STEP III STUDY			
Period	PNW Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Energy Capability of Thermal Installations 2/ aMW	Total Load 3/ aMW	Hydro Load 4/ aMW	Total Load 3/ aMW	Hydro Load 4/ aMW		Period
Aug. 1-15	19363	93.01	24095	80.19	9452	16666.3	7214.3	14277.9	4825.9		Aug. 1-15
Aug. 16-31	19285	92.64	24050	80.19	9296	16599.2	7303.2	14220.4	4924.4		Aug. 16-31
September	18708	89.87	23822	78.53	9160	16102.5	6942.5	13794.9	4634.9		September
October	19495	93.65	26765	72.84	9431	16779.9	7348.9	14375.3	4944.3		October
November	21603	103.77	29107	74.22	9591	18594.4	9003.4	15929.7	6338.7		November
December	23244	111.65	31680	73.37	9796	20006.8	10210.8	17139.7	7343.7		December
January	24230	116.39	32979	73.47	9739	20855.5	11116.5	17866.8	8127.8		January
February	22832	109.68	31493	72.50	9635	19652.2	10017.2	16835.9	7200.9		February
March	21567	103.60	29415	73.32	9129	18563.4	9434.4	15903.1	6774.1		March
April 1-15	20288	97.45	27790	72.97	8623	17462.5	8839.5	14960.0	6337.0		April 1-15
April 16-30	20386	97.93	27872	72.97	7094	17546.8	10452.8	15032.3	7938.3		April 16-30
May	19576	94.03	25987	75.33	5496	16849.7	11353.7	14435.0	8939.0		May
June	19450	93.43	24672	78.83	8453	16741.2	8288.2	14342.1	5889.1		June
July	19542	93.87	24378	80.16	9535	16820.4	7285.4	14409.9	4874.9		July
Annual Average =	20817.8	100.00		75.50	8929.0	17918.6	8989.6	15350.7	6421.7		Annual Avg
Critical Period Avg (42) =	20942.1			75.30	9018.9	18155.6	9080.4				
Step II Crit. Per. Avg (20) =	21093.3				9075.2						
Step III Crit. Per. Avg:											
Discretionary Draft Method (6)	22308.1				9292.0			16449.6	7157.6		Crit.Per.Avg
Draft for Power Method (7)	21896.8				9312.3			16146.3	6834.0		Crit.Per.Avg
						Input 5/=	**9080.4**	Input 6/=			
								Discretionary Draft		**7157.6**	
								Draft for Power		**6834.0**	
August 1-31	19322.7	92.8	24095.0	80.19	9371.5	16631.7	7260.2	14248.2	4876.7		Aug. 1-31
April 1-30	20337.0	97.7	27872.0	72.97	7858.5	17504.7	9646.2	14996.1	7137.6		Apr. 1-30

1/ The PNW Area 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 1A, line 23).
3/ The total firm load for the Step II/III studies is computed to have the same shape as the load of the PNW Area.
4/ The hydro load is equal to the total load minus the Step I study thermal installations.
5/ Input is the assumed critical period average generation for the Step II hydro studies and is used to calculate the residual hydro loads.
6/ Input is the assumed Step III critical period average generation: Discretionary Draft Input = 7157.6 MW, Draft for Power Input = 6834.0 MW.
The Draft for Power Step III critical period method excludes 306 (aMW) of October surplus (critical period average = 44.7 MW) which cannot be shaped to meet the firm load.

TABLE 4A
SUMMARY OF POWER REGULATIONS FOR STEP I & II
FROM 1999-00 ASSURED OPERATING PLAN

	BASIC DATA		STEP I			STEP II			
PROJECTS	NUMBER OF UNITS	NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE 1000 AF	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE 1000 AF	JANUARY 1946 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	350	103	3008	214	119	108
Kerr	3	160	1219	156	119	1219	152	111	119
Thompson Falls	6	40	0	85	55	0	85	53	57
Noxon Rapids	5	554	231	527	152	0	554	134	200
Cabinet Gorge	4	230	0	239	100	0	239	89	116
Albeni Falls	3	49	1155	23	23	1155	20	23	22
Box Canyon	4	74	0	72	46	0	71	45	47
Grand Coulee	24+3SS	6684	5185	6198	1958	5072	6382	1778	2319
Chief Joseph	27	2614	0	2614	1118	0	2614	1016	1366
Wells	10	840	0	840	414	0	840	385	482
Chelan	2	54	677	51	39	676	51	37	45
Rocky Reach	11	1267	0	1267	575	0	1267	533	694
Rock Island	18	544	0	544	279	0	544	261	330
Wanapum	10	986	0	986	517	0	986	481	603
Priest Rapids	10	912	0	912	495	0	912	469	565
Brownlee	5	675	975	675	241	974	675	313	316
Oxbow	4	220	0	220	99	0	220	124	128
Ice Harbor	6	693	0	693	223	0	693	239	310
McNary	14	1127	0	1127	652	0	1127	637	801
John Day	16	2484	535	2484	954	0	2484	921	1253
The Dalles	22+2F	2074	0	2074	754	0	2074	733	994
Bonneville	18+2F	1147	0	1147	594	0	1147	579	729
Kootenay Lake	0	0	673	0	0	673	0	0	0
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0
Total Base System Hydro		23856	29445	23284	9510	28500	23351	9080	11604
ADDITIONAL STEP I PROJECTS									
Libby	5	600	4980	559	195				
Boundary	6	1055	0	855	370				
Spokane River Plants	24	156	104	165	98				
Hells Canyon	3	450	0	410	193	NOT APPLICABLE TO STEP II			
Dworshak	3	450	2015	447	165				
Lower Granite	6	932	0	930	221				
Little Goose	6	932	0	928	218				
Lower Monumental	6	932	0	922	222				
Pelton, Rereg., & RB	7	423	274	420	128				
Subtotal		5930	7373	5636	1810				
THERMAL INSTALLATION 1/				11341	9019		11341	9075	
RESERVES 2/				-2638	0		-2271	0	
TOTAL RESOURCES				37623	20340		32421	18156	
STEP I, II, & III LOADS 3/				30837	20340		28386	18156	
SURPLUS				6784	0		4036	0	
CRITICAL PERIOD	Starts		September 1, 1928			September 1, 1943			
	Ends		February 29, 1932			April 30, 1945			
	Length (Months)		42 Months			20 Months			
	Study Identification		00-41			00-42			

1/ From Tables 1 and 3
2/ Peak reserves are 8 percent of peak load from Table 3; energy reserve deductions have been included in thermal plant energy capability.
3/ Step I load from Table 1. Step II & III energy load from Table 3. Step II & III Peak Load is derived using the same ratio of energy to peak load as Step I

TABLE 4B
SUMMARY OF POWER REGULATIONS FOR STEP III
FROM 1999-00 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA NUMBER OF UNITS	BASIC DATA NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE 1000 AF	STEP III 4/ Discretionary Draft Method JANUARY 1937 PEAKING CAP. MW	Discretionary Draft Method CRITICAL PERIOD AVERAGE GEN. MW	Discretionary Draft Method 30 YEAR AVERAGE ANNUAL GEN. MW	Draft for Power Method JANUARY 1937 PEAKING CAP. MW	Draft for Power Method CRITICAL PERIOD AVERAGE GEN. MW	Draft for Power Method 30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES									
CANADIAN									
Mica									
Arrow									
Duncan									
Subtotal									
BASE SYSTEM									
Hungry Horse	4	428	3008	345	194	105	345	179	105
Kerr	3	160	1219	150	139	120	150	126	120
Thompson Falls	6	40	0	85	63	58	85	59	58
Noxon Rapids	5	554	0	554	170	202	554	154	202
Cabinet Gorge	4	230	0	239	112	118	239	102	118
Albeni Falls	3	49	1155	20	17	21	20	18	21
Box Canyon	4	74	0	70	55	47	70	52	47
Grand Coulee	24+3SS	6684	5072	5712	1192	2244	5712	1170	2244
Chief Joseph	27	2614	0	2614	744	1291	2614	717	1291
Wells	10	840	0	840	289	441	840	280	441
Chelan	2	54	676	51	50	42	51	44	42
Rocky Reach	11	1267	0	1267	392	650	1267	376	650
Rock Island	18	544	0	544	189	301	544	181	301
Wanapum	10	986	0	986	344	545	986	331	545
Priest Rapids	10	912	974	912	350	506	912	337	506
Brownlee	5	675	0	675	266	315	675	263	315
Oxbow	4	220	0	220	121	128	220	117	128
Ice Harbor	6	693	0	693	191	310	693	182	310
McNary	14	1127	0	1127	505	751	1127	482	751
John Day	16	2484	0	2484	718	1220	2484	689	1220
The Dalles	22+2F	2074	0	2074	588	974	2074	570	974
Bonneville	18+2F	1147	0	1147	469	695	1147	450	695
Kootenay Lake	0	0	673	0	0	0	0	0	0
Coeur d'Alene Lake	0	0	223	0	0	0	0	0	0
Total Base System Hydro		23856	13000	22809	7158	11084	22809	6879	11084
ADDITIONAL STEP I PROJECTS									
Libby	5	600							
Boundary	6	1055							
Spokane River Plants	24	156							
Hells Canyon	3	450			NOT APPLICABLE TO STEP III				
Dworshak	3	450							
Lower Granite	6	932							
Little Goose	6	932							
Lower Monumental	6	932							
Pelton, Rereg., & RB	7	423							
Subtotal		5930							
THERMAL INSTALLATION 1/				11341	9292		11341	9312	
RESERVES 2/				-1945	0		-1945	0	
TOTAL RESOURCES				32206	16450		32206	16191	
STEP I, II, & III LOADS 3/				24318	16450		24318	16146	
SURPLUS				7886	0		7886	45	
CRITICAL PERIOD	Starts				November 1, 1936			October 1, 1936	
	Ends				April 30, 1937			April 30, 1937	
	Length (Months)				6 Months			7 Months	
	Study Identification				00-13			00-13	

1/ From Tables 1 and 3
2/ Peak reserves are 8 percent of peak load from Table 3; energy reserve deductions have been included in thermal plant energy capability.
3/ Step I load from Table 1. Step II & III energy load from Table 3. Step II & III Peak Load is derived using the same ratio of energy to peak load as Step I.
4/ For Step III critical period average generation two methods were used : "Discretionary Draft" method and "Draft for Power" method.

TABLE 5

COMPUTATION OF CANADIAN ENTITLEMENT FOR
1999-00 ASSURED OPERATING PLAN

A. Optimum Power Generation in Canada and the U.S. (From 00-42)
B. Optimum Power Generation in the U.S. Only (From 00-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 00-22)

Determination of Dependable Capacity Credited to Canadian Storage - MW

	CAPACITY ENTITLEMENT					
	Discretionary Draft Method			Draft for Power Method		
	(A)	(B)	(C)	(A)	(B)	(C)
Step II - Critical Period Avg. Generation 1/	9080.4	9080.2	9046.2	9080.4	9080.2	9046.2
Step III - Critical Period Avg. Generation 2/	7157.6	7157.6	7157.6	6878.8	6878.8	6878.8
Gain Due to Canadian Storage	1922.8	1922.6	1888.6	2201.7	2201.5	2167.5
Average Critical Period Load Factor in % 3/	75.30	75.30	75.30	75.30	75.30	75.30
Dependable Capacity Gain 4/	2553.4	2553.1	2508.0	2923.7	2923.4	2878.3
Canadian Share of Dependable Capacity 5/	1276.7	1276.5	1254.0	1461.9	1461.7	1439.1

Determination of Increase in Average Annual Usable Energy - Average MW

	ENERGY ENTITLMENT		
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8990.3	8989.7	8956.5
Thermal Replacement Energy 7/	2129.5	2130.0	2154.9
Other Usable Secondary Energy 8/	193.5	195.1	197.8
System Annual Average Usable Energy	11313.3	11314.8	11309.2
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6422.2	6422.2	6422.2
Thermal Replacement Energy 7/	3182.0	3182.0	3182.0
Other Usable Secondary Energy 8/	590.1	590.1	590.1
System Annual Average Usable Energy	10194.3	10194.3	10194.3
Average Annual Usable Energy Gain 9/	1119.0	1120.5	1114.9
Canadian Share of Avg. Annual Energy Gain 5/	559.5	560.3	557.4

1/ Step II values were obtained from the 00-42, 00-12, and 00-22 studies, respectively.
2/ Step III values were obtained from the 00-13 study. The Draft for Power method includes 306 aMW of surplus in October which cannot be shaped to meet the firm loads.
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/ Avg. secondary generation limited to Potential Thermal Displacement market.
8/ Forty percent (40%) of the remaining secondary energy.
9/ Difference between Step II and Step III Annual Average Usable Energy.

TABLE 6

COMPARISON OF RECENT DDPB STUDIES

	1995-96 1/	1996-97	1997-98	Discret. Draft 1998-99 6/	Draft for Power 1998-99 6/	Discret. Draft 1999-00 6/	Draft for Power 1999-00 6/
PNW AREA AVG. ANNUAL LOAD (MW)	18898.0	20324.6	20387.3	20479.6	-	20817.8	-
-Avg. Annual/Jan. Load (%)	86.7	87.1	86.9	86.3	-	85.9	-
-Avg. C.P. Load Factor (%)	75.2	75.3	75.2	75.6	-	75.3	-
-Avg. Annual Firm Exports	905.0	511.2	926.3	1075.3	-	1202.7	-
-Avg. Annual Firm Surplus (MW) 2/	255.0	610.5	433.2	534.6	-	708.1	-
THERMAL INSTALLATIONS (MW) 3/							
-January Peak Capability	9225	10381	10514	11003	-	1134	-
-Critical Period (C.P.) Energy	6491	7975	8141	8462	-	9019	-
-C.P. Minimum Generation	1621	675	632	789	-	1047	-
-Avg. Annual System Export Sales	1440	887	1133	1265	-	1392	-
-Avg. Ann. Displaceable Market	3462	6104 4/	6105	6345	-	6490	-
					-		
INSTALLED HYDRO CAPACITY (MW)	29680	29785	29786	29786	-	29786	-
-Base System	23736	23841	23856	23856	-	23856	-
STEP I/II/III C.P. (MONTHS)	42/20/6	42/20/7	42/20/6	42/20/5.5	42/20/6.5	42/20/6	42/20/7
BASE STREAMFLOWS AT THE DALLES (cfs) 5/							
-Step I 50-yr.Avg. Streamflow	179502	179338	180748	181664	-	181664	-
-Step I C.P. Average	113177	113053	114127	114496	-	114496	-
-Step II C.P. Average	100146	100036	101008	101537	-	101525	-
-Step III C.P. Average	64733	64756	64870	57185	58483	64879	64960
CAPACITY BENEFITS (MW)							
-Step II C.P. Generation	8892.9	8963.5	9018.0	9064.1	-	9080.4	-
-Step III C.P. Generation	7113.5	6895.5	7169.4	7061.2	6773.9	7157.6	6878.8
-Step II Gain over Step III	1779.4	2068.0	1848.6	2002.9	2290.2	1922.8	2201.7
-CANADIAN ENTITLEMENT	1183.4	1373.4	1229.6	1324.7	1514.7	1276.7	1461.9
-Change due to Mica Reop	0.7	1.0	0.0	-0.4	-	0.2	-
-Benefit in Sales Agreement	576.0	486.0	471.0	416.0	-	200.0	-
ENERGY BENEFITS (aMW)							
-Step II Firm Hydro	8928.3	8871.0	8963.0	9000.0	-	8990.3	-
-Step II Thermal Displacement	1422.3	2037.4	2037.7	2101.3	-	2129.5	-
-Step II Other Usable	421.0	207.0	194.9	188.3	-	193.5	-
-Step II Total Usable	10771.6	11115.4	11195.6	11289.6	-	11313.3	-
-Step III Firm Hydro	6401.4	6445.0	6579.0	6502.1	-	0	-
-Step III Thermal Displacement	2123.8	2951.6	2902.9	3066.8	-	0.0	-
-Step III Other Usable	940.0	623.7	607.2	595.3	-	0	-
-Step III Total Usable	9465.2	10020.3	10089.1	10164.2	-	10194.3	-
-CANADIAN ENTITLEMENT	653.2	547.5	553.3	562.7	-	559.5	-
-Change due to Mica Reoperation	-2.0	-0.9	-2.8	-4.1	-	-0.8	-
-ENTITLEMENT in Sales Agreement	268.0	254.0	246.0	215.0	-	103.0	-
STEP II PEAK CAPABILITY (MW)	30530	31472	31647	32074	-	32421	-
STEP II PEAK LOAD (MW)	24069	26252	26587	27317	-	28386	-
STEP III PEAK CAPABILITY (MW)	30299	31409	31456	31793	-	32206	-
STEP III PEAK LOAD (MW)	20273	22350	22859	23391	-	24318	-

FOOTNOTES FOR TABLE 6

1. The 1995-96 Assured Operating Plan (AOP) was adopted from 1994-95 AOP study.

2. Average annual firm surplus is the additional shaped load including the surplus shaped in May and/or June.

3. Thermal installations include all existing and planned thermal resources. The 1995-96 AOP thermal installations also included thermal imports. Beginning with the 1996-97 AOP, thermal installations also included cogeneration, renewable thermal, thermal NUG/PURPA, and seasonal exchange imports minus plant sales.

4. The increased thermal installations beginning with 1996-97 AOP are due to increased plant factors at existing plants and the addition of new cogeneration projects.

5. Beginning with the 1998-99 AOP studies, the 1990 level modified flows were used and no additional irrigation depletions were anticipated for the 1999 level. There is, however, an adjustment for Grand Coulee pumping and return flow.

6. Beginning with the 1998-99 AOP studies, Column A reflects values based on "Discretionary Draft" critical period method; Column B reflects values based on "Draft for Power" critical period method.

CHART 1

1999-00 DETERMINATION OF DOWNSTREAM OF 30 YEAR MONTHLY HYDRO GENERATION (aMW)