COLUMBIA RIVER TREATY

ASSURED OPERATING PLAN

AND

DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR

OPERATING YEAR 1993 - 94

COLUMBIA RIVER TREATY OPERATING COMMITTEE

JULY 1989

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR THE YEAR 1993-94

HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN

FOR OPERATING YEAR 1993-94

July 1989

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

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.

A 30-year System Regulation Study/8 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 and discharges.

This Assured Operating Plan includes firm energy shifting as part of the United States optimum operation. This was incorporated in the studies as follows:

(a) The load in the first year of the critical period was maximized subject to draft constraints at each major reservoir. The maximum allowable drawdown at the end of July 1929 (the end of the first year of the critical period) was limited to 700 ksfd at Mica, 300 ksfd at Arrow and 143 ksfd at Duncan. In the 30-year studies, this higher load was served in each year that the reservoir system refilled prior to the start of the year.

(b) Energy shifted into the first year of the critical period was returned at uniform rates beginning in January of the second year of the critical period and continuing through until the end of the critical period. Energy shifted into the first year of the critical period was further shaped into the fall months similar to the load it is expected to serve.

(c) The shifted energy was assumed to add to the initial Step I system firm energy capability in excess of system firm energy loads. As such, it was considered to increase the system sales to loads outside the Pacific Northwest Area.

Pursuant to the Entity Agreements (/2 and /3), the Entities have also prepared an Alternative Operating Plan/9 that excludes energy shifting. The Alternative Operating Plan, while documented separately, is part of this Assured Operated Plan. The United States Entity may elect to adopt either set of operating rule curves and associated operating rules for inclusion in the Detailed Operating Plan.

Pursuant to the Entity Agreements (/2 and /3), the United States Entity has agreed to deliver 19.8 MW of average annual usable energy, but no dependable capacity, to the Canadian Entity during the period 1 August 1993 through 31 July 1994. This delivery does not alter the obligation of the Canadian Entity to deliver 2.3 MW of dependable capacity, but no average annual usable energy, to the United States Entity during the period 1 April 1993 through 31 March 1994, resulting from changes in downstream power benefits attributable to the operation of Canadian Treaty storage for optimum benefits in both Canada and the United States rather than for optimum in the United States alone.

The data assumed for this Assured Operating Plan will undergo review by the Entities immediately prior to the 1993-94 operating year and such data may be revised to reflect data and criteria current at that time. Should the Entities fail to agree on such revisions, then either the operating rule curves and associated operating rules contained in this document or those contained in the Alternative Operating Plan /9, at the discretion of the United States Entity, will form the basis for the Detailed Operating Plan for 1993-94.

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 4.6 MW increase in the Canadian Entitlement to annual average usable energy and a 2.3 MW decrease in the Entitlement to dependable capacity, compared to the operation for optimum generation in the United States alone. This is within the limits specified by the Treaty.

System Regulation Studies for the Assured Operating Plan were based on 1993-94 estimated loads and resources in British Columbia and in the United States Pacific Northwest System. The Entities have agreed that the 1993-94 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 to estimated 1993-94 conditions, were used. The streamflows were derived from the 1980 Level Modified Streamflows/10 with an update in irrigation depletion estimates from the 1970 Level Modified Streamflows/11.

The Critical Rule Curve for these studies was determined from Bonneville Power Administration Study 94-41. 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 February 1932. 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 storage at Mica in an on-call flood control situation.

3. 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 1993-94 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 alone.

The Columbia River Treaty Operating Committee agreed that for the 1993-94 Assured Operating Plan the three quantities would be assigned the following relative values:

Quantity	Relative Value
Firm energy capability (Avg. MW)	3
Dependable peaking capability (MW)	1
Average annual usable secondary energy (Avg. MW)	2

The three quantities were added after weighting on this basis and there was 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 1 shows the results from the studies adopted for the 1993-94 Assured Operating Plan and from studies designed to achieve optimum generation in the United States.

4. Operating Rule Curves

The operation of Canadian storage during the 1993-94 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 curves are first determined for the individual Canadian projects, which in turn are used to determine Operating Rules Curves for the individual projects which are then summed to yield the Composite Operating Rule Curve for the whole of Canadian storage. This is in accordance with the provision of 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 Mica, Arrow and Duncan and the Composite Critical Rule Curve for the whole of Canadian storage is included in Table 3.

(b) Refill Curve.

The Refill Curve is a guide to operation of Canadian storage which defines the normal limit of storage draft for 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 system or the Mica and Revelstoke generating plants during subsequent years. The end of the refill period is considered to be 31 July.

The Refill Curve is, in turn, defined by two curves as discussed below. In each case, adjustment should be made for water required for refill of upstream reservoirs when applicable.

(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 Mica, Arrow and Duncan is included as Table 4.

The schedule of outflows used in developing these Assured Refill Curves is the same as the Power Discharge Requirements used in computing the Variable Refill Curve discussed in 4(b)(2) below when The Dalles volume runoff is at 80 million acre-feet.

(2) Variable Refill Curve.

The Variable Refill Curve gives 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 In the system regulation studies the Power Discharge Requirement was made a function of the natural January - July runoff volume at The Dalles, Oregon. In those years when this volume was lower than 80 million acre-feet, the discharge used was that required to meet firm loads while refilling at 80 million acre-feet. In years when the runoff volume at The Dalles exceeded 95 million acre-feet, the Power Discharge Requirement was the project minimum outflow. For intermediate volumes, the Power Discharge Requirement used in computing the Variable Refill Curves was interpolated linearly between the values shown in Tables 5 - 7.

Variable Refill Curves for Mica, Arrow and Duncan for the 30 years of historical record are recorded in Tables 5 - 7. These illustrate the probable range of these curves based on historical conditions. In actual operation in 1993-94, the Power Discharge Requirements will be based on the forecast of unregulated runoff at The Dalles.

(c) Limiting Rule Curve.

The Limiting Rule Curves indicate month-end storage contents which must be maintained to guarantee the system meeting its firm load during the period January 1 - March 31 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 5 - 7.

(d) Upper Rule Curve.

The Upper Rule Curves/12 indicate the end-of-month storage content to which each individual Canadian storage project shall be evacuated for flood control and other requirements. 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 and analysis of system flood control simulations. Each Upper Rule Curve is constrained to be not lower than the Variable Refill Curve, except in those years in which the April-August unregulated volume of runoff for the Columbia River at The Dalles exceeds 120 million acre-feet, and Canadian storage is subject to on-call request. Flood control curves for Mica, Arrow and Duncan for the 30-year study period are shown on Tables 8 - 10; however, the tables do not reflect the constraint that the Upper Rule Curve not be lower than the Variable Refill Curve. Tables 9 and 10 reflect an assumed 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 by the Critical Rule Curve or the Assured Refill Curve, whichever is higher. The Critical Rule Curve for the first year of the critical period is used in the foregoing determination. During the period 1 January through 31 July, the Operating Rule Curve is defined by 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 by 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 all 30 years of historical record are included as Table 11 to illustrate the probable future range of these curves based on historical conditions.

5. Operating Rules

The following rules, used in the 94-41 System Regulation Study, will apply to the operation of Canadian storage in the 1993-94 Operating Year.

(a) Operation Above Operating Rule Curve

The whole of the Canadian storage may 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 5(c) below.

(b) Operation Below Operating Rule Curve

The whole of Canadian storage will not be drafted below its Operating Rule Curve unless:

i) Reservoir storage in the United States system has been drafted to its Energy Content Curve.

ii) Deliveries of secondary energy in the United States are discontinued.

iii) Committed firm thermal and miscellaneous resources not displaced by surplus firm hydro resources are in operation or other replacement energy has been secured from sources other than those committed.

When the above conditions are met, and it is necessary to draft additional storage to produce optimum generation as determined by the Critical Period System Regulation study, the whole of the Canadian storage and reservoir storage in the United States system will be drafted proportionately between its Operating Rule Curve or Energy Content Curve, respectively, and its Composite Critical Rule Curve. The proportionate draft will be made, if necessary, first to the first-year Composite Critical Rule Curve, then between the first and second-year Composite Critical Rule Curve, then second and third-year Composite Critical Rule Curve, etc. When it is necessary to operate the whole of the Canadian storage and the United States reservoir storage below their lowest Composite Critical Rule Curves, each shall be operated proportionately between its lowest Composite Critical Rule Curve and its normal minimum content. However, Mica Reservoir will continue to be operated in accordance with 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 drafts 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 2. Mica monthly outflows will be increased above the values shown in the table in the months from October to June if required to avoid violation of 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 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 2.

Revelstoke has been included in the 1993-94 Assured Operating Plan and has been operated as a run-of-river project.

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 1993-94 will reflect the latest available load, resource, and other pertinent data to the extent the Entities agreed these data should be included in the plan. Beginning on 1 January 1993, the data and criteria contained herein will be reviewed, and updated as agreed by the Entities, to form the basis for a Detailed Operating Plan for the 1993-94 Operating Year. Failing agreement on updating the Assured Operating Plan, the Detailed Operating Plan will include either the data and criteria given in this document or that given in the Alternative Operating Plan/9, at the discretion of the United States Entity. Actual operation during the 1993-94 Operating Year shall be guided by the Detailed Operating Plan.

The operating rules to be used in implementation of the Detailed Operating Plan are generally the same as the operating rules described in this document.

The values used in the Assured Operating Plan studies to define the various rule curves were month-end values only. In actual day-to-day 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,/7 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.

REFERENCES

1 Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans dated May 1983.

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 Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 12 August 1988.

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

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

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

7 Columbia River Treaty Flood Control Operating Plan dated October 1972.

8 BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 94-41, dated 16 June 1989.

9 Hydroelectric Operating Plan, Alternative Operating Plan for Operating Year 1993-94, dated July 1989.

10 The 1980 Level Modified Streamflow, 1928 to 1978, Columbia River and Coastal Basins, dated July 1983.

11 Provisional Report on Modified Flows at Selected Sites, 1928 to 1968 for the 1970 Level of Development, Columbia River and Coastal Basins, Columbia River Water Management Group, Revision 2, dated April 1974 and Provisional Report on Modified Flows at Selected Sites, 1928 to 1968 for the 2020 Level of Development, Columbia River and Coastal Basins, Columbia River Water Management Group, dated May 1974.

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

TABLE 1

COMPARISON OF ASSURED OPERATING PLAN
STUDY RESULTS

	Optimum Generation in Canada and the United States Study No. 94-41	Optimum Generation in the United States Study No. 94-11	Net Gain	Weight	Value
1. Firm Energy Capability (Avg. MW)					
U.S. System (1)	12,082.9	12,084.3	-1.4		
Canada (2)	1,635.6	1,595.5	+40.1		
Total	13,718.5	13,679.8	+38.7	3	+116.1
2. Dependable Peaking Capacity (MW)					
U.S. System (3)	31,586.0	31,583.0	+3.0		
Canada (4)	3,508.0	3,522.0	-14.0		
Total	35,094.0	35,105.0	-11.0	1	-11.0
3. Average Annual Usable Secondary Energy (Avg. MW)					
U.S. System (5)	2,705.8	2,713.9	-8.1		
Canada (6)	134.7	161.7	-27.0		
Total	2,840.5	2,875.6	-35.1	2	-70.2

Net Change in Value = +34.9

Notes:

(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 (Mica + Revelstoke) firm energy capability was determined over the Canadian system critical period beginning 1 October 1940 and ending 30 April 1946.

(3) U.S. system dependable peaking capability was determined from January 1937.

(4) Canadian system (Mica + Revelstoke) dependable peaking capability was determined from December 1944.

(5) U.S. system 30-year average secondary energy limited to secondary market.

(6) Canadian system (Mica and Revelstoke) 30-year average generation minus firm energy capability.

TABLE 2

MICA PROJECT OPERATING CRITERIA
ASSURED OPERATING PLAN

Month	End of Previous Period Arrow Storage Content (ksfd)	Target Operation Period Average Outflow (cfs)	Target Operation End-of-Period Treaty Content(1) (ksfd)	Minimum Outflow (cfs)	Minimum Treaty Content(2) (ksfd)
August 1-15	3 300 - FULL	-	3 456.2	10 000	0.0
	0 - 3 300	27 000			
August 16-31	2 400 - FULL	-	3 529.2	10 000	0.0
	0 - 2 400	27 000			
September	2 500 - FULL	-	3 529.2	10 000	0.0
	0 - 2 500	27 000			
October	2 900 - FULL	-	3 529.2	10 000	0.0
	0 - 2 900	27 000			
November	3 000 - FULL	19 000	-	10 000	0.0
	0 - 3 000	27 000			
December	3 200 - FULL	22 000	-	15 000	1306.2
	2 200 - 3 200	27 000			
	0 - 2 200	34 000			
January	1 700 - FULL	26 000	-	15 000	456.2
	0 - 1 700	34 000			
February	700 - FULL	25 000	-	15 000	0.0
	0 - 700	27 000			
March	500 - FULL	22 000	-	15 000	0.0
	0 - 500	27 000			
April 1-15	0 - FULL	25 000	-	15 000	0.0
April 16-30	0 - FULL	18 000	-	10 000	0.0
May	300 - FULL	10 000	-	10 000	0.0
	0 - 300	15 000			
June	0 - FULL	10 000	-	10 000	0.0
July	2 200 - FULL	-	3 256.2	10 000	0.0
	0 - 2 200	27 000			

Notes:

(1) A maximum outflow of 34000 cfs will apply if the target end-of-period storage content is less than 3529.2 ksfd.

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

COLUMBIA RIVER TREATY
CRITICAL RULE CURVES
END OF MONTH CONTENTS IN KSFD
1993-94 OPERATING YEAR

TABLE 3

MICA

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3529.2	3529.2	3529.2	3428.4	3007.5	2927.5	2056.5	1167.5	584.0	242.4	29.1	115.1	1546.5	2623.5
2ND YR	3149.2	3529.2	3529.2	2952.4	2504.8	1780.0	1054.8	432.4	0.0	0.0	0.0	431.0	1864.5	2986.2
3RD YR	3361.9	3529.2	3529.2	3428.4	2775.6	2049.8	1333.1	707.0	0.0	0.0	0.0	362.3	1861.5	2765.9
4TH YR	2980.6	3139.2	3097.7	2607.6	2042.8	1306.2	456.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0

ARROW

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3579.6	3579.6	3579.5	3444.2	3339.7	2609.8	1789.2	855.8	901.8	263.8	31.3	670.0	2417.0	3488.8
2ND YR	3216.7	2919.7	2801.9	3046.6	2708.7	2661.5	1535.5	988.1	740.8	539.7	851.1	417.3	1212.7	2746.2
3RD YR	3037.3	3065.6	3129.7	2722.2	2655.6	2036.2	1210.9	213.1	339.6	55.6	114.3	307.7	713.7	1341.6
4TH YR	1388.1	1019.7	1139.4	1248.7	614.4	7.6	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

DUNCAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	705.8	705.8	705.7	702.4	705.8	504.1	260.9	76.1	0.1	0.1	0.1	117.6	378.3	562.8
2ND YR	477.4	382.3	288.1	109.4	0.5	0.2	0.5	0.6	0.8	0.0	4.5	16.0	35.6	97.8
3RD YR	158.1	218.6	262.8	115.3	2.6	0.9	1.0	3.4	0.0	0.2	0.0	66.0	44.6	41.6
4TH YR	4.1	2.7	3.3	4.2	0.4	4.5	7.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COMPOSITE

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	7814.6	7814.6	7814.4	7575.0	7053.0	6041.4	4106.6	2099.4	1485.9	506.3	60.5	902.7	4341.8	6675.1
2ND YR	6843.3	6831.2	6619.2	6108.4	5214.0	4441.7	2590.8	1421.1	741.6	539.7	855.6	864.3	3112.8	5830.2
3RD YR	6557.3	6813.4	6921.7	6265.9	5433.8	4086.9	2545.0	923.5	339.6	55.8	114.3	736.0	2619.8	4149.1
4TH YR	4372.8	4161.6	4240.4	3860.5	2657.6	1318.3	488.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COLUMBIA RIVER TREATY
ASSURED REFILL CURVES
END OF MONTH CONTENTS IN KSFD
1993-94 OPERATING YEAR

TABLE 4

MICA

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1788.0	2368.3	2974.8	3155.9	3223.1	3241.3	3237.6	2695.5	2114.3	1840.1	1604.2	1696.6	2655.9	3529.2

ARROW

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
0.0	0.0	0.0	0.0	216.1	253.1	304.5	872.5	980.5	1040.6	1209.6	1983.2	3107.7	3579.6

DUNCAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
55.9	126.8	193.1	223.8	241.3	252.5	262.7	263.5	268.3	277.0	261.7	360.0	540.9	705.8

TABLE 5

DUNCAN VARIABLE REFILL CURVE (KSFD)
1993-94 OPERATING YEAR

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							474.2	438.2	431.6	445.8	466.8	446.2	594.0	705.8
1929-30							472.2	436.2	429.3	443.3	477.2	467.1	605.4	,,
1930-31							416.8	382.0	378.6	399.3	428.6	415.5	594.0	,,
1931-32							1.2	1.6	0.8	0.0	35.6	112.3	447.9	,,
1932-33							,,	,,	,,	,,	0.0	0.0	314.3	,,
1933-34							,,	,,	,,	,,	45.9	144.5	488.3	,,
1934-35							37.4	13.6	28.2	59.2	123.0	179.7	454.5	,,
1935-36							42.2	17.3	19.5	49.4	113.1	185.2	506.0	,,
1936-37							420.3	385.5	380.7	396.6	421.0	407.6	576.2	,,
1937-38							1.2	1.6	0.8	16.2	91.5	168.0	471.8	,,
1938-39							271.7	239.9	238.5	263.4	309.1	326.7	577.0	,,
1939-40							260.3	228.4	234.3	268.8	315.5	328.8	565.7	,,
1940-41							340.0	306.8	308.9	341.9	391.6	406.7	589.1	,,
1941-42							158.8	132.4	141.9	169.9	227.9	280.9	522.6	,,
1942-43							121.4	96.5	105.7	131.9	199.9	280.8	505.0	,,
1943-44							496.5	459.7	457.9	473.1	494.2	479.6	624.0	,,
1944-45							417.5	382.7	381.8	400.0	423.7	408.0	582.4	,,
1945-46							1.2	1.6	0.8	0.0	0.0	56.8	440.9	,,
1946-47							,,	,,	,,	,,	9.3	100.4	453.6	,,
1947-48							,,	,,	,,	,,	43.8	118.7	464.5	,,
1948-49							173.8	147.8	153.6	175.7	233.2	294.2	565.4	,,
1949-50							1.2	1.6	0.8	0.0	61.4	126.9	408.6	,,
1950-51							,,	,,	,,	,,	11.1	92.4	439.6	,,
1951-52							5.5	,,	,,	24.4	95.7	178.3	484.5	,,
1952-53							4.9	,,	,,	23.7	93.2	156.5	450.9	,,
1953-54							1.2	,,	,,	0.0	0.0	18.9	381.9	,,
1954-55							,,	,,	,,	,,	41.5	106.2	386.2	,,
1955-56							,,	,,	,,	,,	0.0	66.8	437.5	,,
1956-57							,,	,,	,,	,,	48.2	119.6	501.4	,,
1957-58							,,	,,	,,	,,	0.0	57.2	453.6	,,
ECC LOWER LIMIT							1.2	1.6	0.8					
POWER DISCHARGE REQUIREMENTS IN CFS						80 MAF--	100	400	400	400	2000	2000	2000	2000
FOR JANUARY THROUGH JULY						90 MAF--	100	100	100	100	100	100	100	100
VOLUME RUNOFF AT THE DALLES						95 MAF--	100	100	100	100	100	100	100	100

ARROW VARIABLE REFILL CURVE (KSFD)
1993-94 OPERATING YEAR

TABLE 6

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							2645.7	3061.8	2974.8	3242.9	3579.6	3314.2	3579.6	3579.6
1929-30							1029.5	1490.9	1496.5	1872.8	2809.8	2753.2	3422.4	,,
1930-31							1435.1	1885.1	1829.5	2178.8	2963.0	2572.4	3421.5	,,
1931-32							627.2	246.2	183.3	0.0	72.4	960.8	2626.1	,,
1932-33							,,	,,	,,	,,	399.2	1142.5	2592.7	,,
1933-34							,,	,,	,,	,,	469.8	1568.5	3016.9	,,
1934-35							,,	,,	,,	,,	555.1	1097.1	2546.6	,,
1935-36							,,	,,	,,	22.1	623.5	1290.5	2870.2	,,
1936-37							2934.7	3342.7	3253.6	3469.2	3579.6	3501.1	3579.6	,,
1937-38							627.2	246.2	183.3	183.8	903.3	1605.8	2868.0	,,
1938-39							1245.9	1701.2	1655.3	2012.2	2883.9	2671.0	3579.6	,,
1939-40							767.7	1231.5	1259.1	1738.9	2692.4	2468.6	3497.4	,,
1940-41							2141.5	2571.8	2550.4	2970.1	3579.6	3574.9	3579.6	,,
1941-42							627.2	721.6	719.3	905.4	1434.5	1817.3	2925.8	,,
1942-43							970.5	980.4	943.3	1092.9	2013.7	2628.1	3257.7	,,
1943-44							3520.5	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	,,
1944-45							2901.9	3310.9	3278.5	3549.7	,,	3528.9	,,	,,
1945-46							627.2	246.2	183.3	0.0	378.3	1168.3	2785.0	,,
1946-47							,,	,,	,,	,,	741.8	1513.8	2857.5	,,
1947-48							,,	,,	,,	,,	506.7	1228.1	2785.1	,,
1948-49							,,	,,	,,	678.5	1732.3	2339.1	3579.6	,,
1949-50							,,	,,	,,	0.0	480.1	1145.3	2478.8	,,
1950-51							,,	,,	,,	34.2	788.1	1478.2	2925.2	,,
1951-52							,,	,,	,,	26.5	729.4	1520.4	3014.6	,,
1952-53							,,	,,	,,	402.5	1192.4	1687.5	2974.2	,,
1953-54							,,	,,	,,	0.0	159.8	863.0	2474.3	,,
1954-55							,,	,,	,,	,,	458.3	1062.3	2380.3	,,
1955-56							,,	,,	,,	,,	311.0	1192.8	2767.9	,,
1956-57							,,	,,	,,	,,	308.3	1027.4	3100.1	,,
1957-58							,,	,,	,,	,,	338.1	1078.8	2794.7	,,
ECC LOWER LIMIT							627.2	246.2	183.3					

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS IN CFS	80 MAF--	5000	5000	23000	25000	25000	40000	45000	45000
FOR JANUARY THROUGH JULY	90 MAF--	5000	5000	5000	5000	5000	5000	5000	5000
VOLUME RUNOFF AT THE DALLES	95 MAF--	5000	5000	5000	5000	5000	10000	28000	30000

MICA VARIABLE REFILL CURVE (KSFD)
1993-94 OPERATING YEAR

TABLE 7

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							3529.2	3529.2	3419.8	3240.4	3157.3	2635.9	3089.1	3529.2
1929-30							,,	2979.5	2343.6	2217.0	2299.9	2017.2	2808.0	,,
1930-31							,,	3248.3	2608.2	2451.8	2460.4	2037.6	2882.3	,,
1931-32							827.5	710.8	665.8	824.4	1066.0	1189.9	2516.0	,,
1932-33							762.8	650.4	622.7	780.7	1000.1	1085.0	2354.3	,,
1933-34							317.6	0.0	0.0	15.8	358.0	828.3	2604.3	,,
1934-35							382.4	174.9	60.5	178.7	429.5	574.6	2035.5	,,
1935-36							1055.5	722.1	463.1	501.3	721.5	862.2	2467.0	,,
1936-37							3529.2	3529.2	3372.8	3184.4	3148.6	2649.9	3121.2	,,
1937-38							1125.8	1005.7	961.1	1114.4	1328.1	1417.2	2606.6	,,
1938-39							3529.2	3121.4	2495.1	2367.6	2400.2	2061.6	3112.8	,,
1939-40							,,	2863.8	2254.6	2128.9	2192.4	1852.4	2875.1	,,
1940-41							,,	3452.5	2832.2	2687.4	2761.2	2421.7	3102.9	,,
1941-42							1061.5	821.7	659.1	721.9	939.9	1063.8	2392.9	,,
1942-43							1754.7	1621.4	1579.2	1703.2	1936.4	2056.6	2842.7	,,
1943-44							3529.2	3529.2	3478.2	3289.5	3228.8	2758.1	3258.3	,,
1944-45							,,	,,	3451.9	3280.1	3202.6	2684.1	3178.3	,,
1945-46							501.1	394.2	347.3	504.3	752.8	880.3	2510.5	,,
1946-47							678.5	567.8	549.9	721.3	979.8	1150.6	2580.3	,,
1947-48							603.6	491.6	458.6	607.6	839.5	938.7	2467.3	,,
1948-49							2314.5	2169.5	2111.2	2217.5	2351.8	2343.4	3232.0	,,
1949-50							926.0	810.1	753.5	897.6	1116.5	1165.4	2280.9	,,
1950-51							967.7	850.9	826.5	985.2	1225.5	1288.1	2639.2	,,
1951-52							1339.4	1211.9	1162.4	1287.5	1480.6	1586.0	2784.5	,,
1952-53							1643.1	1512.2	1472.4	1599.8	1754.5	1744.5	2751.3	,,
1953-54							505.1	398.1	382.0	550.9	789.5	853.5	2253.3	,,
1954-55							954.0	830.3	806.8	956.9	1181.4	1252.1	2304.9	,,
1955-56							824.9	708.2	663.4	812.8	1040.3	1184.1	2555.0	,,
1956-57							987.4	870.2	840.3	995.7	1213.0	1272.1	2881.7	,,
1957-58							832.7	718.8	695.1	860.8	1100.6	1169.0	2647.7	,,
ECC LOWER LIMIT							317.6	0.0	0.0					
POWER DISCHARGE REQUIREMENTS IN CFS						80 MAF--	3000	22000	22000	23000	23000	25000	28000	28000
FOR JANUARY THROUGH JULY						90 MAF--	3000	3000	3000	3000	3000	3000	3000	3000
VOLUME RUNOFF AT THE DALLES						95 MAF--	3000	3000	3000	3000	10000	10000	18000	20000

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
1993-94 OPERATING YEAR
KSFD

TABLE 8

	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	323.7	231.4	288.9	283.4	298.0	403.6	560.8	705.8
1929-30	,,	,,	,,	,,	,,	,,	323.2	218.3	206.2	242.8	258.9	368.8	529.4	,,
1930-31	,,	,,	,,	,,	,,	,,	361.9	221.3	245.5	249.3	265.1	392.3	558.2	,,
1931-32	,,	,,	,,	,,	,,	,,	277.3	65.5	65.5	80.9	109.1	281.3	609.8	,,
1932-33	,,	,,	,,	,,	,,	,,	273.7	,,	,,	75.1	94.3	191.7	573.3	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	65.5	127.0	339.6	606.4	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	83.5	187.2	488.1	,,
1935-36	,,	,,	,,	,,	,,	,,	333.6	179.5	162.8	152.2	194.1	406.1	705.8	,,
1936-37	,,	,,	,,	,,	,,	,,	379.9	292.4	201.6	243.3	259.4	353.2	540.8	,,
1937-38	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	77.1	83.5	217.3	542.6	,,
1938-39	,,	,,	,,	,,	,,	,,	,,	,,	,,	82.8	107.2	408.8	705.8	,,
1939-40	,,	,,	,,	,,	,,	,,	277.3	126.0	102.3	198.9	219.6	450.7	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	287.2	120.0	147.7	248.3	264.2	394.8	536.5	,,
1941-42	,,	,,	,,	,,	,,	,,	273.7	85.2	136.6	277.6	295.9	503.4	705.8	,,
1942-43	,,	,,	,,	,,	,,	,,	275.0	78.1	92.7	86.1	121.1	200.0	644.2	,,
1943-44	,,	,,	,,	,,	,,	,,	340.3	222.8	266.7	273.0	288.0	403.9	554.6	,,
1944-45	,,	,,	,,	,,	,,	,,	328.5	174.9	163.8	102.1	103.3	409.6	705.8	,,
1945-46	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	75.7	95.6	322.3	647.5	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	102.0	314.0	629.6	,,
1947-48	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	65.5	300.5	705.8	,,
1948-49	,,	,,	,,	,,	,,	,,	273.7	116.9	,,	73.8	102.0	330.1	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	65.5	,,	65.5	65.5	184.0	525.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	285.1	534.2	,,
1951-52	,,	,,	,,	,,	,,	,,	277.3	,,	,,	,,	67.4	92.4	255.0	,,
1952-53	,,	,,	,,	,,	,,	,,	357.6	127.0	125.5	101.9	114.1	244.2	525.1	,,
1953-54	,,	,,	,,	,,	,,	,,	307.4	65.5	65.5	73.2	84.1	237.1	547.6	,,
1954-55	,,	,,	,,	,,	,,	,,	303.4	178.9	185.0	116.8	125.2	154.5	488.8	,,
1955-56	,,	,,	,,	,,	,,	,,	277.3	65.5	65.5	65.5	84.7	266.6	585.4	,,
1956-57	,,	,,	,,	,,	,,	,,	273.7	73.1	,,	74.5	89.9	376.1	655.8	,,
1957-58	,,	,,	,,	,,	,,	,,	282.5	84.7	,,	77.1	96.3	359.4	705.8	,,

TABLE 9

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
1993-94 OPERATING YEAR
KSFD

	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	2688.8	2713.2	3075.4	3088.5	3111.2	3235.8	3579.6	3579.6
1929-30	,,	,,	,,	,,	,,	,,	2416.9	2375.0	1812.6	2012.0	2084.4	2448.6	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	2844.6	3047.5	3075.4	3088.5	3111.2	3235.8	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2371.6	1712.7	1008.4	1016.1	1126.6	2224.6	,,	,,
1932-33	,,	,,	,,	,,	,,	,,	2363.6	1720.2	,,	1008.4	1036.6	1761.7	3034.5	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1784.9	2327.4	3579.6	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1725.7	3034.5	,,
1935-36	,,	,,	,,	,,	,,	,,	2949.5	2236.7	,,	1070.1	1373.5	2186.4	3579.6	,,
1936-37	,,	,,	,,	,,	,,	,,	2980.2	3075.4	2118.4	2774.9	2819.5	3042.6	,,	,,
1937-38	,,	,,	,,	,,	,,	,,	2363.6	1720.2	1008.4	1082.9	1278.3	1831.2	3147.6	,,
1938-39	,,	,,	,,	,,	,,	,,	,,	,,	,,	1100.9	1265.5	2471.7	3579.6	,,
1939-40	,,	,,	,,	,,	,,	,,	2371.6	2061.7	,,	1162.3	1336.7	2294.0	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	2363.6	1720.2	1811.3	3088.5	3111.2	3235.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	2535.4	2570.7	2993.2	,,	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	1111.2	1322.0	1440.3	2389.1	,,
1943-44	,,	,,	,,	,,	,,	,,	2850.2	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	,,
1944-45	,,	,,	,,	,,	,,	,,	2598.7	2577.0	2036.2	1603.7	1677.8	2301.7	3289.4	,,
1945-46	,,	,,	,,	,,	,,	,,	2363.6	1720.2	1008.4	1072.6	1242.3	2201.4	3579.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1360.6	2147.4	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1036.6	1183.2	2216.8	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	2363.6	1720.2	,,	1144.6	1376.0	2494.5	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1008.4	1113.8	2232.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1355.5	3337.9	,,
1951-52	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1345.2	1792.6	3013.9	,,
1952-53	,,	,,	,,	,,	,,	,,	3000.1	1720.2	,,	1057.2	1172.9	1476.3	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	2363.6	,,	,,	,,	1134.3	1628.0	1898.0	,,
1954-55	,,	,,	,,	,,	,,	,,	2485.8	2641.5	2472.5	1262.6	1276.9	1653.7	3224.8	,,
1955-56	,,	,,	,,	,,	,,	,,	2371.6	1712.7	1008.4	1008.4	1216.6	1990.6	2993.4	,,
1956-57	,,	,,	,,	,,	,,	,,	2363.6	1720.2	,,	1077.8	1224.3	2651.4	3579.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	1046.9	1190.9	2242.6	,,	,,

TABLE 10

MICA
FLOOD CONTROL STORAGE RESERVATION CURVES
1993-94 OPERATING YEAR
KSFD

	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	3233.8	3201.6	3428.4	3428.4	3428.4	3457.3	3492.7	3529.2
1929-30	,,	,,	,,	,,	,,	,,	3124.0	3071.4	2809.2	2869.8	2869.8	3045.7	3221.7	,,
1930-31	,,	,,	,,	,,	,,	,,	3293.6	3332.9	3428.4	3416.9	3416.9	3457.3	3492.7	,,
1931-32	,,	,,	,,	,,	,,	,,	3105.7	2803.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1932-33	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1935-36	,,	,,	,,	,,	,,	,,	3334.6	3017.8	,,	,,	,,	2808.9	3212.6	,,
1936-37	,,	,,	,,	,,	,,	,,	3345.7	3378.0	2926.9	3171.1	3171.1	3191.9	3382.2	,,
1937-38	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1938-39	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	2853.9	3228.8	,,
1939-40	,,	,,	,,	,,	,,	,,	3105.7	2948.8	,,	2513.5	2513.5	2781.5	3188.8	,,
1940-41	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2808.7	3428.4	3428.4	3457.3	3431.4	,,
1941-42	,,	,,	,,	,,	,,	,,	,,	,,	2480.5	3078.2	3078.2	3249.2	3159.1	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	2480.5	2480.5	2781.5	3149.6	,,
1943-44	,,	,,	,,	,,	,,	,,	3296.2	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1944-45	,,	,,	,,	,,	,,	,,	3199.2	3149.2	2895.3	2716.9	2716.9	2938.9	3172.6	,,
1945-46	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1951-52	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1952-53	,,	,,	,,	,,	,,	,,	3353.3	2807.2	,,	,,	,,	,,	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	3101.7	,,	,,	,,	,,	,,	,,	,,
1954-55	,,	,,	,,	,,	,,	,,	3152.9	3174.0	3063.0	2560.7	2560.7	,,	,,	,,
1955-56	,,	,,	,,	,,	,,	,,	3105.7	2803.2	2480.5	2480.5	2480.5	2695.5	3172.6	,,
1956-57	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	2781.5	3149.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,

COLUMBIA RIVER TREATY
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS IN KSFD
1993-94 OPERATING YEAR

TABLE 11

FLOW YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7814.4	7575.0	7268.6	6355.2	5289.5	3831.5	3363.1	3157.7	3075.5	4039.8	6304.5	7814.6
1929-30	,,	,,	,,	,,	,,	,,	4529.8	,,	,,	,,	,,	,,	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	4935.4	,,	,,	,,	,,	,,	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	1455.9	958.6	849.9	824.4	1174.0	2263.0	5590.0	,,
1932-33	,,	,,	,,	,,	,,	,,	1391.2	898.2	806.8	780.7	1399.3	2227.5	5261.3	,,
1933-34	,,	,,	,,	,,	,,	,,	946.0	247.8	184.1	15.8	873.7	2541.3	6109.5	,,
1934-35	,,	,,	,,	,,	,,	,,	1047.0	434.7	272.0	237.9	1107.6	1851.4	5036.6	,,
1935-36	,,	,,	,,	,,	,,	,,	1724.9	985.6	665.9	572.8	1458.1	2337.9	5843.2	,,
1936-37	,,	,,	,,	,,	,,	,,	5289.5	3831.5	3363.1	3157.7	3075.5	4039.8	6304.5	,,
1937-38	,,	,,	,,	,,	,,	,,	1754.2	1253.5	1145.2	1314.4	2322.9	3191.0	5946.4	,,
1938-39	,,	,,	,,	,,	,,	,,	4746.2	3807.9	3333.3	3144.1	3075.5	4006.5	6304.5	,,
1939-40	,,	,,	,,	,,	,,	,,	4265.6	3796.4	3329.1	3149.5	,,	4008.6	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	5289.5	3831.5	3363.1	3157.7	,,	4039.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	1847.5	1675.7	1520.3	1797.2	2377.4	3162.0	5841.3	,,
1942-43	,,	,,	,,	,,	,,	,,	2846.6	2590.4	2628.2	2875.7	3013.7	3960.6	6268.6	,,
1943-44	,,	,,	,,	,,	,,	,,	5289.5	3831.5	3363.1	3157.7	3075.5	4039.8	6304.5	,,
1944-45	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1945-46	,,	,,	,,	,,	,,	,,	1129.5	642.0	531.4	504.3	1131.1	2105.4	5736.4	,,
1946-47	,,	,,	,,	,,	,,	,,	1306.9	815.6	734.0	721.3	1730.9	2764.8	5891.4	,,
1947-48	,,	,,	,,	,,	,,	,,	1232.0	739.4	642.7	607.6	1390.0	2285.5	5716.9	,,
1948-49	,,	,,	,,	,,	,,	,,	3115.5	2563.5	2448.1	2694.3	3047.0	3974.0	6304.5	,,
1949-50	,,	,,	,,	,,	,,	,,	1554.4	1057.9	937.6	897.6	1658.0	2437.6	5168.3	,,
1950-51	,,	,,	,,	,,	,,	,,	1596.1	1098.7	1010.6	1019.4	2024.7	2858.7	6004.0	,,
1951-52	,,	,,	,,	,,	,,	,,	1972.1	1459.7	1346.5	1338.4	2305.7	3284.7	6155.0	,,
1952-53	,,	,,	,,	,,	,,	,,	2275.2	1760.0	1656.5	2026.0	2889.8	3540.6	6081.0	,,
1953-54	,,	,,	,,	,,	,,	,,	1133.5	645.9	566.1	550.9	949.3	1735.4	5109.5	,,
1954-55	,,	,,	,,	,,	,,	,,	1582.4	1078.1	990.9	956.9	1681.2	2420.6	5071.4	,,
1955-56	,,	,,	,,	,,	,,	,,	1453.3	956.0	847.5	812.8	1351.3	2443.7	5760.4	,,
1956-57	,,	,,	,,	,,	,,	,,	1615.8	1118.0	1024.4	995.7	1569.5	2419.1	6257.4	,,
1957-58	,,	,,	,,	,,	,,	,,	1461.1	966.6	879.2	860.8	1438.7	2305.0	5896.0	,,

DETERMINATION OF DOWNSTREAM POWER BENEFITS
FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1993-94

DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 1993-94

July 1989

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 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 1993-94 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; and in the document, "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated May 1983, and as clarified in the Entity Agreements, signed July 28 and August 12, 1988, on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit (DDPB) Studies

The Canadian Entitlement Benefits were computed from the following studies:

Step I - based on 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 - based on 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 - based on 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 1993-94, separate determinations were carried out relating to:

i) 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, and

ii) the decrease in downstream power benefits due to the operation of Canadian Treaty storage for optimum power generation at-site in Canada and downstream in Canada and the United States of America, instead of operation of Canadian Treaty storage for optimum power generation in the United States of America only.

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 1):

Dependable Capacity = 1,266.5 MW
Average Annual Energy = 655.7 MW

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 1993-94 operating year are based on the formula X - (Y - Z), where the quantities X, Y, and Z are defined in POP. The quantity X is derived from the difference between last year's Assured Operating Plan studies 93-42 and 93-13 and the quantity Y is derived from the difference between last year's Assured Operating Plan studies 93-12 and 93-13. These computations are set out in the 1992-93 agreement. 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, was computed to be (See Table 1):

Dependable Capacity = 1,243.1 MW
Average Annual Energy = 642.1 MW

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

Dependable Capacity = 1,476.9 - (1,476.9 - 1,243.1) = 1,243.1 MW
Average Annual Energy = 593.7 - (592.3 - 642.1) = 643.5 MW

The computed Canadian Entitlement exceeds these amounts.

4. Effect on Sale of Canadian Entitlement

The Canadian Entitlement to downstream power benefits for operating year 1993-94 was sold to the United States of America under the Canadian Entitlement Purchase Agreement dated 13 August 1964. The studies developed for this sale included the assumption of operation of Treaty storage for optimum power generation downstream in the United States of America only. The Canadian Entitlement determined from the 1993-94 Assured Operating Plan for this condition would have been:

Dependable Capacity = 1,268.8 MW
Average Annual Energy = 651.1 MW

Since the 1993-94 Assured Operating Plan was in fact 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 with the Canadian Entitlement to downstream power benefits shown above indicates an increase in Canadian Entitlement of 4.6 MW of average annual usable energy, and a decrease of 2.3 MW in dependable capacity.

Accordingly, the Entities are agreed that the United States Entity is entitled to receive 2.3 MW of dependable capacity, but not entitled to receive any energy during the period 1 April 1993 through 31 March 1994, from B.C. Hydro & Power Authority, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement dated 13 August 1964.

5. Summary of Canadian Entitlement Computations

The following Tables and Chart summarize the study results:

Table 1. Computation of Canadian Entitlement For 1993-94 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 2. Summary of Power Regulations from 1993-94 Assured Operating Plan for the Computation of Canadian Entitlement to Downstream Power Benefits

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system.

Table 3. Determination of Loads for 1993-94 Step I, II, and III Studies for Assured Operating Plan with Shift

This table shows the computation of the Step I, II, and III loads and the effect of including shifted firm energy in the Step I and II studies. 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 current forecast data. 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 POP.

Table 4. Determination of Displaceable Thermal Market for 1993-94 Assured Operating Plan

This table shows the computation of the potential thermal displacement market for the downstream power benefit determination of usable energy. The potential thermal displacement market was limited to the existing and scheduled thermal energy capability after allowance for reserves and minimum thermal generation, and reductions for the thermal resources used outside the PNW Area.

Table 5. Comparison of Recent Assured Operating Plan Studies

Table 6. Comparison of Recent DDPB Studies

Tables 5 and 6 tabulate various data from the five most recent studies.

Chart 1. 1993-94 Determination of Downstream Power Benefits 30-Year 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.

6. Summary of Changes From Previous Year

Pursuant to the July 28, 1988 Entity Agreements on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, there were several changes in the 1993-94 studies when compared to previous studies. An explanation of the more important changes compared to last year's study is given below.

(a) Loads and Resources

The average annual Pacific Northwest Area load estimate increased by 142 MW. In previous Assured Operating Plans the PNUCC load forecast was used, but for 1993-94 studies the more up-to-date BPA load forecast was used. Surplus firm energy capability was shaped into May as shown on Table 3.

Average annual exports out of the region increased from last year by 525 MW. The effect of exports was not included in the computation of the load shape for the Step II/III studies.

The critical period thermal capability increased 344 MW due to changes in operation and maintenance schedules.

Step I hydro independent nominal installed peaking capacity increased 182 MW. The increase was due to miscellaneous hydro resources now being included as hydro independents.

In order to cover a 229 MW annual average firm deficit in the region a resource acquisition was added. Based on expected resource additions for this size of deficit, the resources were assumed to be approximately 128 MW of conservation and the remainder small hydro.

In years that reservoirs refilled and first-year firm energy load carrying capability could be adopted, the amount of shift for the Step I study was 750 MW September through December and 375 MW January through July. In years that reservoirs did not refill 225 MW of energy was returned beginning in January 1930 through February 1932. Return was also performed in January through July 1935, January 1938 through July 1939, January through July 1942, and July 1944 through July 1946. For Step II the shift was 319.9 MW September through December 1944, 106.6 MW January through July and 225 MW of return in August 1944 through April 30, 1945 and also in January through April 1937.

(b) Operating Procedures

Priest Lake was operated as a natural lake in Step II and III.

Adjustments to Canadian rule curves were made in order to minimize the effect of Canadian storage re-operation on the U.S. system, consistent with Section 4c of the Principles and Procedures agreements.

Corra Linn was drafted to the full amount of usable storage declared in Annex B at the end of the critical period in order to provide an optimum power operation in Step II and III. This operation was not included in Step I, but will be included next year.

Similarly, Brownlee reservoir storage was fully drafted by the end of the critical period in Step II and III, but was not drafted empty at the end of the critical period in Step I. This will be corrected next year to provide an optimum power operation as required.

(c) Step III Critical Period

The Step III study had a new critical period of 5 1/2 months, November through April 15, 1937.

(d) Downstream Power Benefit Computation

The potential displaceable thermal market was decreased by a uniform amount equal to the amount of thermal power being used to meet loads outside the PNW area. This amount of system sales included net exports out of the region and the amount of shifted firm energy. However the 225 MW return was treated as a combustion turbine and was an addition to the thermal displacement market.

For the Step II and III computation of surplus energy limited to thermal displacement market, the years shifted and returned were carried over from Step I. The years of return were 1930, 1931, 1932, 1935, 1938, 1939, 1942, 1945 and 1946. This was done so operating procedures would be consistent among Step I, II and III.

The Canadian Entitlement to capacity benefits decreased by about 210 MW and the Entitlement to energy benefits increased by 62 aMW compared to the 1992-93 Entitlement. The large decrease in capacity benefits is mainly due to the change in load factor caused by excluding exports from the PNW Area loads and by the shorter Step III critical period length and resulting increase in Step III critical period average generation. The increase in energy benefits is mainly attributable to the change in monthly load shape due to the exclusion of the exports from the PNW area loads.

The inclusion of shifted firm energy load carrying capability resulted in an increase in Canadian Entitlement of 19.8 MW of average annual usable energy and a decrease of 6.9 MW of dependable capacity.

TABLE 1

COMPUTATION OF CANADIAN ENTITLEMENT FOR
1993-94 ASSURED OPERATING PLAN :

A. Optimum Power Generation in Canada and the U.S. (From 94-42)
B. Optimum Power Generation in the U.S. Only (From 94-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 94-22)

Determination of Dependable Capacity Credited to Canadian Storage - MW

	(A)	(B)	(C)
Step II - Critical Period Avg. Generation 1/	8,869.5	8,872.8	8,835.6
Step III - Critical Period Avg. Generation 2/	7,036.3	7,036.3	7,036.3
Gain Due to Canadian Storage	1,833.2	1,836.5	1,799.3
Average Critical Period Load Factor in % 3/	72.37	72.37	72.37
Dependable Capacity Gain 4/	2,533.1	2,537.6	2486.2
Canadian Share of Dependable Capacity 5/	1,266.5	1,268.8	1,243.1

Determination of Increase in Average Annual Usable Energy - Average MW

Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8,970.2	8,973.4	8,936.7
Thermal Replacement Energy 7/	1,148.2	1,123.9	1,133.5
Other Usable Secondary Energy 8/	492.8	504.6	513.6
System Annual Average Usable Energy	10,611.1	10,601.9	10,583.8
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6,485.2	6,485.2	6,485.2
Thermal Replacement Energy 7/	1,783.1	1,783.1	1,783.1
Other Usable Secondary Energy 8/	1,031.4	1,031.4	1,031.4
System Annual Average Usable Energy	9,299.7	9,299.7	9,299.7
Average Annual Usable Energy Gain 9/	1,311.4	1,302.2	1,284.1
Canadian Share of Avg. Annual Energy Gain 5/	655.7	651.1	642.1

1/ Step II values were obtained from the Shift 94-42, 94-12, and 94-22 studies, respectively.
2/ Step III values were obtained from the Shift 94-13 study.
3/ Critical period load factor from Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ One-half of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load.
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 2

SUMMARY OF POWER REGULATIONS
FROM 1993-94 ASSURED OPERATING PLAN

	BASIC DATA		STEP I			STEP II				STEP III			
PROJECTS	NUMBER OF UNITS	NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	30 YEAR AVERAGE ANNUAL GENERATION MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	30 YEAR AVERAGE ANNUAL GENERATION MW
HYDRO RESOURCES													
CANADIAN													
Mica			7,000			7,000							
Arrow			7,100			7,100							
Duncan			1,400			1,400							
Subtotal			15,500			15,500							
BASE SYSTEM													
Hungry Horse	4	328	3,161	269	93	3,008	213	112	102	3,008	328	218	103
Kerr	3	160	1,219	148	113	1,219	151	102	118	1,219	152	142	115
Thompson Falls	6	40		40	38		40	38	37		40	40	36
Noxon Rapids	5	554	231	536	149		554	134	203		554	171	203
Cabinet Gorge	4	225		230	100		230	87	117		230	107	117
Albeni Falls	3	49	1,155	24	25	1,155	22	23	24	1,155	22	19	23
Box Canyon	4	74		71	46		70	44	48		70	55	47
Grand Coulee	24	6,684	5,185	6,382	2,018	5,072	6,348	1,782	2,312	5,072	5,776	1,209	2,254
Chief Joseph	27	2,687		2,687	1,123		2,687	1,026	1,377		2,687	747	1,306
Wells	10	820		820	391		820	366	452		820	271	419
Rocky Reach	11	1,267		1,267	562		1,267	526	677		1,267	390	634
Rock Island	18	544		544	273		544	257	323		544	187	295
Wanapum	10	986		986	502		986	477	590		986	343	533
Priest Rapids	10	912		912	499		912	473	566		912	348	510
Brownlee	5	675	975	675	211	974	675	277	277	974	675	271	277
Oxbow	4	220		220	87		220	112	114		220	112	114
Ice Harbor	6	693		693	212		693	225	296		693	175	295
McNary	14	1,127		1,127	629		1,124	585	751		1,124	452	701
John Day	16	2,484	535	2,484	923		2,484	928	1,264		2,484	711	1,219
The Dalles	22+2F	2,076		2,076	734		2,076	713	975		2,076	564	953
Bonneville	18+2F	1,147		1,147	557		1,147	547	682		1,147	454	650
Kootenay Lake			673			673				673			
Chelan	2	54	677	51	38	676	51	38	45	676	51	51	42
Coeur d'Alene Lake			223			223				223			
Total Base System Hydro		23,806	29,535	23,389	9,323	28,500	23,314	8,872	11,350	13,000	22,858	7,037	10,846
ADDITIONAL STEP I PROJECTS													
Libby	5	604	4,980	460	180								
Boundary	6	1,055		855	369								
Spokane River Plants	24	157	104	155	91								
Hells Canyon	3	450		421	170								
Dworshak	3	460	2,015	460	177								
Lower Granite	6	930		930	210								
Little Goose	6	930		930	211								
Lower Monumental	6	930		930	199								
Pelton, Rereg., and Round Butte	7	423	274	418	127								
Subtotal		5,939	7,373	5,559	1,734								
THERMAL RESOURCES 1/													
Small Existing Thermal Plants				1,656	334								
Centralia #1 & #2				1,280	1,103								
Jim Bridger #1, #2, #3, & #4				2,003	1,649								
Colstrip #1,#2,#3,#4				1,310	978								
Trojan				1,104	804								
Boardman				530	405								
Valmy				242	195								
WNP #2				1,095	788								
Total Thermal Resources				9,220	6,256		9,218	6,305			9,218	6,574	
RESERVES 2/				(2,394)	0		(1,953)	0			(1,647)	0	
TOTAL RESOURCES				35,774	17,313		30,579	15,177			30,429	13,611	
LOADS													
ESTIMATED LOAD PACIFIC NORTHWEST AREA 3/				29,936	18,486		24,414	15,177			20,593	13,611	
Firm Exports				1413	960								
Surplus Firm Exports				0	219								
Firm Imports				(682)	(170)								
Miscellaneous Contracts				(169)	(131)								
Other Coordinated Hydro		3,188	5,486	(2,667)	(1,031)								
Independent Hydro Resources		1,963	4,342	(1,481)	(803)								
Estimated Hydro Maintenance				1,548	12								
Added Conservation/Resources				0	(229)								
TOTAL STEP I LOADS				27,898	17,313								
SURPLUS				7,876	0		6,166	0			9,836	0	
CRITICAL PERIOD Starts				September 1, 1928			September 1, 1943				November 1, 1936		
Ends				February 29, 1932			April 30, 1945				April 15, 1937		
Length (Months)				42 Months			20 Months				5.5 Months		
Study Identification				94-41			94-42				94-13		

1/ Thermal energy capabilities are based on an annual plant factor of 60 percent the first full year of operation and 75 percent thereafter unless specified differently by project owner. These annual plant factors include deductions for energy resources and scheduled maintenance.
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 II or III Peak Load is equal to the Step II or III Annual Average Load multiplied by the ratio of the PNW Area January Peak Load to the Annual Average Load.

TABLE 3

DETERMINATION OF LOADS FOR
1993-94 STEP I, II, and III STUDIES
FOR ASSURED OPERATING PLAN WITH SHIFT

Pacific Northwest Area Loads					STEP I STUDY							STEP II STUDY						STEP III STUDY		
Period	Energy Load w/o FirmSurp MW 1/	Annual Energy Load Shape Percent	Base Peak Load MW	Load Factor Percent	FIRM SURPLUS MW	Peak Bias MW	1st Year Energy Shift/ Shape MW	Total 1st Yr Load MW 2/	Return Energy MW 3/	Total 2nd/3rd Yr Load MW 2/	PNW Thermal Resources MW 4/	Total Load MW 5/	Hydro Load MW 6/	Shift/ Shape MW	1st Yr. Hydro Load MW	Return Energy MW 7/	2nd Yr. Hydro Load MW	Total Load MW 5/	Hydro Load MW 6/	Period
Aug. 1-15	17004	92.56	22051	77.11	0	0	0.0	17004.0	-225.0	16779.0	6804	13867.3	7063.3	0	7063.3	-225.0	6838.3	11697.0	4893.0	Aug. 1-15
Aug. 16-31	16925	92.13	22006	76.91	0	0	0.0	16925.0	-225.0	16700.0	6804	13802.9	6998.9	0	6998.9	-225.0	6773.9	11642.7	4838.7	Aug. 16-31
Sept. 1-15	16602	90.38	22713	73.09	0	0	750.0	17352.0	-225.0	16377.0	6849	13539.4	6690.4	319.9	7010.3	-225.0	6465.4	11420.5	4571.5	Sept. 1-15
Sept. 16-30	16562	90.16	22622	73.21	0	0	750.0	17312.0	-225.0	16337.0	6849	13506.8	6657.8	319.9	6977.7	-225.0	6432.8	11393.0	4544.0	Sept. 16-30
October	17338	94.38	24812	69.88	0	0	750.0	18088.0	-225.0	17113.0	6885	14139.7	7254.7	319.9	7574.6	-225.0	7029.7	11926.8	5041.8	October
November	19126	104.11	27010	70.81	0	0	750.0	19876.0	-225.0	18901.0	6926	15597.8	8671.8	319.9	8991.7	-225.0	8446.8	13156.8	6230.8	November
December	20716	112.77	28938	71.59	0	0	375.0	21091.0	-225.0	20491.0	6920	16894.5	9974.5	319.9	10294.4	-225.0	9749.5	14250.5	7330.5	December
January	21181	115.30	29936	70.75	0	0	375.0	21556.0	-225.0	20956.0	6928	17273.8	10345.8	106.6	10452.4	-225.0	10120.8	14570.4	7642.4	January
February	20151	109.69	28473	70.77	0	0	375.0	20526.0	-225.0	19926.0	6775	16433.8	9658.8	106.6	9765.4	-225.0	9433.8	13861.9	7086.9	February
March	18738	102.00	26272	71.32	0	0	375.0	19113.0	-225.0	18513.0	6018	15281.4	9263.4	106.6	9370.0	-225.0	9038.4	12889.9	6871.9	March
April 1-15	17782	96.80	24843	71.58	0	0	375.0	18157.0	-225.0	17557.0	5200	14501.8	9301.8	106.6	9408.4	-225.0	9076.8	12232.2	7032.2	April 1-15
April 16-30	17879	97.33	24925	71.73	0	0	375.0	18254.0	-225.0	17654.0	4716	14580.9	9864.9	106.6	9971.5	-225.0	9639.9	12298.9	7582.9	April 16-30
May	17229	93.79	23953	71.93	3000	4858	375.0	20604.0	-225.0	20004.0	3394	14050.8	10656.8	106.6	10763.4	0.0	10656.8	11851.8	8457.8	May
June	17317	94.27	22881	75.68	0	0	375.0	17692.0	-225.0	17092.0	4590	14122.5	9532.5	106.6	9639.2	0.0	9532.5	11912.3	7322.3	June
July	17357	94.49	22785	76.18	0	0	375.0	17732.0	-225.0	17132.0	6797	14155.2	7358.2	106.6	7464.8	0.0	7358.2	11939.9	5142.9	July
Annual Average =	18370.1	100.0		72.57	254.79		436.6	19061.5	-225.0	18399.9	6152.1	14981.4	8829.3	169.2	8998.1	-168.3	8661.0	12636.8	6484.7	Annual Avg.
Crit. Per. Avg.=	18486.4			72.37	218.48						6256.1	15174.2						13610.6		
Step II Crit. Per. Avg =	18606.5										6304.7		8869.5							
Step III Crit. Per. Avg =	19785.7										6574.3								7036.3	Crit.Per.Avg
							Shift/Shape 42 Month Crit. Per. Avg.			18690.5						Computed Critical Period Avg	8870.0			
																Input Critical Per. Avg. 8/=	8869.5	Input 8/=	7036.3	
																	*********		*********	
August 1-31	16964.5		22028.5		0	0	0.0	16964.5	-225.0	16739.5	6804.0	13835.1	7031.1	0.0	7031.1	-225.0	6806.1	11669.9	4865.9	Aug. 1-31
September 1-30	16582.0		22667.5		0	0	750.0	17332.0	-225.0	16357.0	6849.0	13523.1	6674.1	319.9	6994.0	-225.0	6449.1	11406.7	4557.7	Sept.1-30
April 1-30	17830.5		24884.0		0	0	375.0	18205.5	-225.0	17605.5	4958.0	14541.3	9583.3	106.6	9690.0	-225.0	9358.3	12265.6	7307.6	Apr. 1-30

Notes: 1. The PNW Area load does not include the exports or firm deficit but does include pumping. The computation of the load shape for Step II/III studies used these loads.
2. Step I study loads also include exports which are shown on Table 4, Line 4.
3. During the critical period Step I shifted energy is returned from Jan. 1930 through Feb. 1932.
4. The thermal installations include large thermal, combustion turbines and existing thermal.
5. The total firm load for the Step II/III studies is computed to have the same shape as the load of the Pacific Northwest Area.
6. The hydro load is equal to the total load minus the Step I study thermal installations.
7. During the critical period Step II shifted energy is returned from Aug. 1944 through Apr. 30, 1945.
8. Input is the critical period average generation for the Step II/III hydro studies used to calculate the residual hydro loads.

TABLE 4

DETERMINATION OF DISPLACEABLE THERMAL MARKET
FOR 1993-94 ASSURED OPERATING PLAN

(Energy in Average MW)

	Aug 1-15	Aug 16-31	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	Apr 1-15	Apr 16-30	May	June	July	Annual Average
THERMAL RESOURCES															
1. Total Thermal Resources	6804.0	6804.0	6849.0	6885.0	6926.0	6920.0	6928.0	6775.0	6018.0	5200.0	4716.0	3394.0	4590.0	6797.0	6152.1
2. Minimum Thermal Generation	1964.0	1964.0	1778.0	1898.0	2191.0	2191.0	2191.0	2191.0	1814.0	1645.0	1401.0	1285.0	1275.0	1898.0	1848.8
3. Displaceable Thermal Resources	4840.0	4840.0	5071.0	4987.0	4735.0	4729.0	4737.0	4584.0	4204.0	3555.0	3315.0	2109.0	3315.0	4899.0	4303.3
SYSTEM SALES															
4. Total Exports/Incl Exchanges	1074.0	1074.0	1078.0	879.0	854.0	916.0	872.0	830.0	825.0	868.0	825.0	1050.0	1100.0	1284.0	968.5
5. Total Export Exchanges	196.0	196.0	196.0	0.0	25.0	50.0	50.0	25.0	0.0	0.0	0.0	0.0	196.0	196.0	78.0
6. Exports w/o Exchanges	878.0	878.0	882.0	879.0	829.0	866.0	822.0	805.0	825.0	868.0	825.0	1050.0	904.0	1088.0	890.5
7. Additional Net Exchange Exports	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
8. Net Exchanges/Exports	878.4	878.4	882.4	879.4	829.4	866.4	822.4	805.4	825.4	868.4	825.4	1050.4	904.4	1088.4	
9. Firm Surplus Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3000.0	0.0	0.0	
10. System Sales (Subtotal)	878.4	878.4	882.4	879.4	829.4	866.4	822.4	805.4	825.4	868.4	825.4	4050.4	904.4	1088.4	
SHIFT/SHAPE															
11. Shift/Shape	0.0	0.0	750.0	750.0	750.0	750.0	375.0	375.0	375.0	375.0	375.0	375.0	375.0	375.0	
12. Total System Sales w/ shift	878.4	878.4	1632.4	1629.4	1579.4	1616.4	1197.4	1180.4	1200.4	1243.4	1200.4	4425.4	1279.4	1463.4	1614.1
13. Uniform Average Annual System Sales	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	1614.1	
14. PNW THERMAL DISPLACM MKT W/SHIFT =	3225.9	3225.9	3456.9	3372.9	3120.9	3114.9	3122.9	2969.9	2589.9	1940.9	1700.9	494.9	1700.9	3284.9	2689.1
RETURN															
15. Total System Sales w/o return	878.4	878.4	882.4	879.4	829.4	866.4	822.4	805.4	825.4	868.4	825.4	4050.4	904.4	1088.4	1145.6
16. Uniform Average Annual System Sales	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	
17. PNW THERMAL DISPLACM MKT W/O RETURN	3694.4	3694.4	3925.4	3841.4	3589.4	3583.4	3591.4	3438.4	3058.4	2409.4	2169.4	963.4	2169.4	3753.4	3157.6
18. Return, combustion turbine	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	0.0	0.0	0.0	
19. PNW THERMAL DISPLACM MKT W/RETURN =	3919.4	3919.4	4150.4	4066.4	3814.4	3808.4	3816.4	3663.4	3283.4	2634.4	2394.4	963.4	2169.4	3753.4	3325.9

NOTES:

Line 1 = Total Thermal Resources from the Step I study includes those located in the PNW and those not located in the PNW which meet Step I system load.
Line 2 = Minimum generation requirement for above resources.
Line 3 = Displaceable Thermal Resources from the Step I study. Line 1 minus line 2.
Line 4 = Total Exports Including Exchanges consists of all firm contract sales of energy exported to meet non-PNWA load.
Line 5 = These exports are balanced by corresponding seasonal exchange imports.
Line 6 = Sum of the Step I study firm contract sales of energy exported to meet non-PNWA Loads minus the exchanges. Line 4 minus line 5.
Line 7 = This is an additional export, the portion of the seasonal exchange contracts not balanced by a corresponding import.
Line 8 = Line 6 plus line 7.
Line 9 = Firm Surplus Energy Sales in the Step I study assumed to be exported to PSW.
Line 10 = Line 8 plus line 9.
Line 11 = Amount of Shift/Shape.
Line 12 = Line 10 plus line 11.
Line 13 = Uniform Average Annual Sales, calculated from Line 12.
Line 14 = PNW Thermal Displacement Market = Displaceable Thermal Resources minus the Yearly Average of Net Sales, adjusted by shift/shape. Line 3 minus line 13.
Line 15 = Line 10.
Line 16 = Uniform Average Annual Sales, calculated from Line 15.
Line 17 = PNW Thermal Displacement Market = Displaceable Thermal Resources minus the Yearly Average of Net Sales. Line 3 minus line 16.
Line 18 = Amount of Return which is a backup combustion turbine.
Line 19 = PNW Thermal Displacement Market = Line 17 plus line 18.

TABLE 5

COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	1989-90	1990-91	1991-92	1992-93	1993-94
MICA TARGET OPERATION (ksfd or cfs)					
- AUG 1	3456.2	3456.2	FULL	3456.2	3456.2
- AUG 2	FULL	FULL	FULL	FULL	FULL
- SEP	FULL	FULL	FULL	FULL	FULL
- OCT	10000	10000	FULL	FULL	10000
- NOV	3122.2	3122.2	3122.2	3246.2	19000
- DEC	26000	23000	23000	22000	22000
- JAN	26000	27000	23000	27000	26000
- FEB	23000	24000	23000	25000	25000
- MAR	17000	20000	18000	23000	22000
- APR 1	15000	15000	18000	27000	25000
- APR 2	10000	10000	18000	10000	18000
- MAY	10000	10000	10000	10000	10000
- JUN	10000	10000	10000	10000	10000
- JUL	3356.2	3356.2	3456.2	3256.2	3256.2
CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)					
NOV 1928 (-41)	533.1	606.5	533.0	690 3	761.6
APR 1929 (-41)	6767.9	7227.1	7049.3	7368.5	7754.1
JUL 1929 (-41)	464.0	759.1	707.1	1036.3	1139.5
AUG 1929 (-41)	8.1	135.9	183.3	560.0	983.4
NOV 1928 (-11)	351.2	538.7	526.7	690.3	501.7
JUL 1929 (-11)	375.6	761.7	708.0	1036.3	1143.0
U.S. STEP I GAINS AND LOSSES (MW)					
- Firm Energy	0	0	-0.2	0.0	-1.4
- Dependable Capacity	-10	+2	0	-6.0	+3.0
- Secondary Energy	-9	-20	+10.5	+16.8	-8.1
BCH STEP I GAINS AND LOSSES (MW)					
- Firm Energy	+72	+26	+12.1	+87.1	+40.1
- Dependable Capacity	-16	-1	-3	+1.0	-14.0
- Secondary Energy	-70	-12	-2.8	-63.2	-27.0
HYDROREG SECONDARY LOAD (MW)					
- AUG 1	11949	8927	10796	11070	10655
- AUG 2	11826	8895	10750	11070	10655
- SEP	11881	8701	10528	9981	10092
- OCT	11977	8936	10726	9981	10237
- NOV	11903	8819	10637	9864	10083
- DEC	12698	8838	10632	9857	10074
- JAN	12731	8853	10677	10996	10914
- FEB	12783	8909	10734	10990	10765
- MAR	12448	8624	10324	10757	10405
- APR 1	10917	8268	9885	10390	10235
- APR 2	10352	7831	9804	10164	10933
- MAY	9874	8394	10135	7156	7114
- JUN	10927	8542	10266	10615	10079
- JUL	12064	8926	10761	11081	10740

TABLE 6

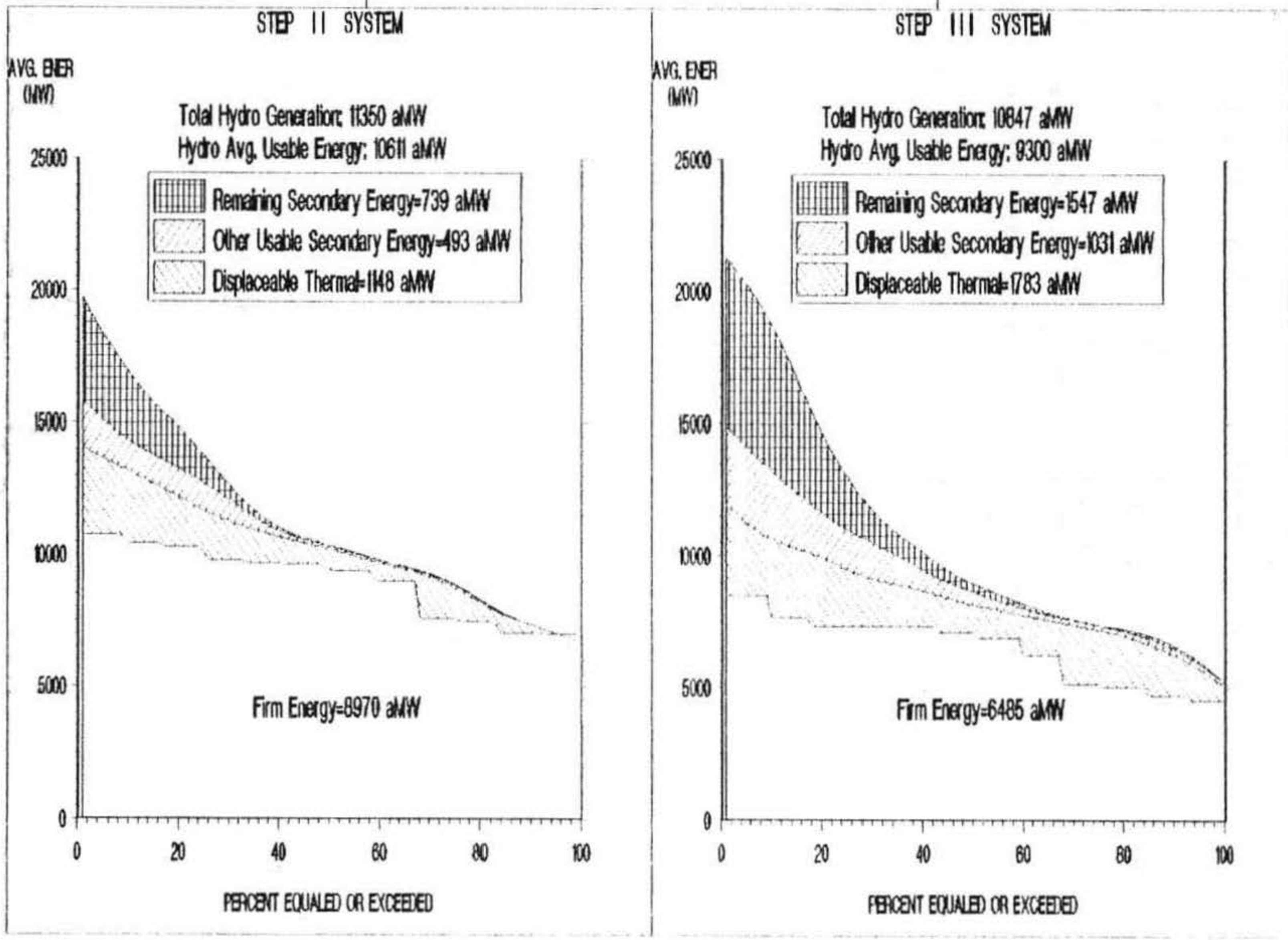
COMPARISON OF RECENT DDPB STUDIES

	1989-90	1990-91	1991-92	1992-93	1993-94
PNW AREA AVG. ANNUAL LOAD (MW)	20026	18103	18449	18228	18370
- Avg. Annual/Jan. Load (%)	84.26	87.52	87.97	87.67	86.73
- Avg. C.P. Load Factor (%) 1/	75.08	68.54	69.43	68.98	72.37
- Avg. Annual Firm Exports	186	333	376	444	969
- Avg. Annual Firm Surp.(MW)	-632	492	239	388	255
THERMAL RESOURCES (MW) 2/					
- January Peak Capability	11547	9249	9249	9218	9220
- C.P. Energy	7229	5831	5800	5912	6256
- C.P. Minimum Generation	1793	1894	1862	1916	1881
- Avg. Annual System Export Sales	NA	NA	NA	832	1146
- Avg. Ann. Displaceable Market 3/	5436	3937	3938	3095	2689
INSTALLED HYDRO CAPACITY (MW) 4/	34578	34633	34584	29737	29745
- Base System	23808	23808	23808	23808	23806
STEP I/II/III C.P. (MONTHS)	42.5/20/7	42/20/7	42/20/7	42/20/7	42/20/5.5
BASE STREAMFLOWS AT THE DALLES (cfs)					
- Step I Avg. Annual Streamflow	174109	173996	175557	175456	178235
- Step I C.P. Average	112139	112054	112996	112920	112843
- Step II C.P. Average 5/	98777	98717	98193	99637	99548
- Step III C.P. Average 6/	62081	62502	62200	60661	57498
CAPACITY BENEFITS (MW)					
- Step II C.P. Generation	8965.8	8944.9	8903.8	8909.4	8869.5
- Step III C.P. Generation	6951.0	6960.7	6919.6	6871.9	7036.3
- Step II Gain over Step III	2014.8	1984.2	1984.2	2037.5	1833.2
- CANADIAN ENTITLEMENT	1341.8	1447.5	1428.9	1476.9	1266.5
- Change due to Mica Reop.	0.0	0.0	0.0	0.0	-2.3
- Benefit in Sales Agreement	1017.	1022.	932.	844.	755.
ENERGY BENEFITS (Avg. MW)					
- Step II Firm Hydro	8728.7	8773.1	8735.3	8898.2	8970.2
- Step II Thermal Displacement	2057.6	1701.0	1732.1	1327.0	1148.2
- Step II Other Usable	284.8	403.1	396.8	484.0	492.8
- Step II Total Usable	11071.1	10877.2	10864.2	10709.2	10611.1
- Step III Firm Hydro	6254.2	6452.2	6417.0	6659.0	6485.2
- Step III Thermal Displacement	2986.8	2402.3	2408.9	1922.4	1783.1
- Step III Other Usable	697.3	861.6	863.7	940.5	1031.4
- Step III Total Usable	9938.3	9716.1	9689.6	9521.9	9299.7
- CANDADIAN ENTITLEMENT	566.4	580.6	587.3	593.7	655.7
- Change due to Mica Reop.	-3.4	-2.7	-3.5	+1.4	+4.6
- Entitlement in Sales Agreement	349.	330.	318.	305.	293.
STEP II PEAK CAPABILITY (MW)	32810	30603	30611	30518	30579
STEP II PEAK LOAD (MW)	25596	24269	24215	24645	24414
STEP III PEAK CAPABILITY (MW)	32756	30613	30574	30612	30429
STEP III PEAK LOAD (MW)	21626	20413	20352	20893	20593

FOOTNOTES FOR TABLE 6

1. The 1989 through 1992 studies included firm contract exports in the computation of the Step I average critical period load factor and the Step II/III study load shape.
2. Thermal resources include combustion turbines, and all existing and planned thermal.
3. Displacement market for the 1993-94 Assured Operating Plan with shifted firm energy is 2689; with energy returned is 3326.
4. Beginning with the 1992-93 Assured Operating Plan, other coordinated hydro and independent hydro were included as adjustments to the Step I load.
5. The 1989 through 1992 Step II/III studies did not update irrigation depletions other than Grand Coulee pumping.
6. The 1993-94 Assured Operating Plan Step III has a 5 1/2 month critical period.

1993-94
DETERMINATION
OF
DOWNSTREAM
POWER BENEFITS
30-YEAR HYDRO
GENERATION- MW



COLUMBIA RIVER TREATY
HYDROELELCTRIC OPERATING PLAN

ALTERNATIVE OPERATING PLAN
FOR OPERATING YEAR 1993-94

HYDROELECTRIC OPERATING PLAN

ALTERNATIVE OPERATING PLAN

FOR OPERATING YEAR 1993-94

July 1989

1. Introduction

In accordance with the Entity Agreements on Principles/1 and on Changes to Procedures/2 for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, the Entities have prepared an Alternative Operating Plan that excludes firm energy shifting. The United States Entity has determined that this Alternative Operating Plan is not part of the optimum United States operation. Therefore, in accordance with Section 3 of the Agreement on Principles, this Alternative Operating Plan has not been adopted for the Assured Operating Plan. However, at the discretion of the United States Entity, the operating rule curves and associated operating rules contained in this Alternative Operating Plan may be adopted for inclusion in the Detailed Operating Plan.

This Alternative Operating Plan was prepared in accordance with the same principles and procedures as were used in the Assured Operating Plan/3 except for the exclusion of firm energy shifting. The criteria and content of the Alternative Operating Plan is essentially the same as for the Assured Operating Plan, however the details of the system operation are somewhat different. For this reason the descriptions of the various rule curves are not repeated. These may be reviewed by referring to the main document./3 However, the tables describing the new study comparisons, Mica operating rules, rule curves and power discharge requirements are included.

A 30-year System Regulation Study/4 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 and discharges.

This document outlines the operating rules for the Alternative Operating Plan and records the incremental change in downstream benefits due to the inclusion of shifted firm energy in the Assured Operating Plan. Inclusion of firm energy shifting results in a 19.8 MW increase in the Canadian Entitlement to average annual usable energy and a 6.9 MW decrease in the Canadian Entitlement to dependable capacity. Pursuant to the Entity Agreements (/1 and /2), the United States Entity is obligated to deliver 19.8 MW of average annual usable energy, but is not obligated to deliver any dependable capacity, to the Canadian Entity during the period 1 August 1993 through 31 July 1994.

2. System Regulation Studies

In accordance with Annex A, Paragraph 7, of the Treaty, the Columbia River Treaty Operating Committee conducted system regulation studies including energy shifting 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 1.4 MW increase in the Canadian Entitlement to average annual usable energy and 3.1 MW loss in Entitlement to dependable capacity compared to an operation for optimum generation in the United States alone. This is within the limits specified by the Treaty.

3. 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 1993-94 Alternative 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 alone. The same weights were used in both the Alternative Operating Plan and the Assured Operating Plan studies.

Table 1 shows the results from the studies adopted for the 1993-94 Alternative Operating Plan and from studies designed to achieve optimum generation in the United States.

4. Operating Rules

The following rules, used in the 30-year System Regulation Study 4/, will apply to the operation of Canadian storage if the Alternative Operating Plan is adopted in the Detailed Operating Plan for the 1993-94 Operating Year.

(a) Mica Operating Rules

Mica project operation will be determined by the end of previous period Arrow storage content as shown in Table 2. Mica monthly outflows will be increased above the values shown in the table in the months from October to June if required to avoid violation of the Upper Rule Curve.

Under this Alternative 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 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 2.

(b) Rule Curves

The operation of Canadian storage during the 1993-94 Operating Year shall be guided by a Composite 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 as described in the Assured Operating Plan./3

Table 3 documents the Critical Rule Curves for Mica, Arrow and Duncan and the Composite Critical Rule Curve for the whole of Canadian storage.

Table 4 documents the Assured Refill Curves for Mica, Arrow and Duncan.

Tables 5-7 document the Variable Refill Curves, Power Discharge Requirements and Limiting Rule Curves for Duncan, Arrow and Mica respectively.

Tables 8-10 document the Upper Rule Curves for Duncan, Arrow and Mica respectively.

Table 11 illustrates the range in Composite Operating Rule curves for the whole of Canadian storage for all 30 years of the historical record. It was developed by combining the individual project operating rule curves using the same criteria as outlined in the Assured Operating Plan.

Revelstoke has been included in the 1993-94 Alternative Operating Plan and has been operated as a run-of-river project.

5. Implementation

The Entities have agreed that each year a Detailed Operating Plan will be prepared for the immediately succeeding operating year. As described in the Assured Operating Plan /3, the United States Entity may elect to adopt either the rule curves and associated operating criteria contained in this document or those contained in the Assured Operating Plan document/3 for inclusion in the Detailed Operating Plan. The Entities may also include any other changes considered advantageous to both countries. Actual operation during the 1993-94 Operating Year shall be guided by the Detailed Operating Plan.

REFERENCES

1 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.

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

3 Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 1993-94, dated July 1989.

4 BPA Hydroelectric Power Planning Program, Alternative Operating Plan 30-year System Regulation Study 94-41(shape), dated 6 June 1989.

TABLE 1

COMPARISON OF ALTERNATIVE OPERATING PLAN STUDY RESULTS

	Optimum Generation in Canada and the United States	Optimum Generation in the United States			
	Study No. 94-41 (Shape)	Study No. 94-41 (Shape)	Net Gain	Weight	Value
1. Firm Energy Capability (Avg. MW)					
U.S. System (1)	12,108.2	12,110.0	-1.8		
Canada (2)	1,636.9	1,585.1	+51.8		
Total	13,745.1	13,695.1	+50.0	3	+150.0
2. Dependable Peaking Capacity (MW)					
U.S. System (3)	31,745.0	31,722.0	+23.0		
Canada (4)	3,506.0	3,524.0	-18.0		
Total	35,251.0	35,246.0	+5.0	1	5.0
3. Average Annual Usable Secondary Energy (Avg. MW)					
U.S. System (5)	2,961.4	2,955.2	+6.2		
Canada (6)	133.0	163.8	-30.8		
Total	3,094.4	3,119.0	-24.6	2	-49.2

Net Change in Value = 105.8

Notes:

(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 (Mica + Revelstoke) firm energy capability was determined over the Canadian system critical period beginning 1 October 1940 and ending 30 April 1946.

(3) U.S. system dependable peaking capability was determined from January 1937.

(4) Canadian system (Mica + Revelstoke) dependable peaking capability was determined from December 1944.

(5) U.S. system 30-year average secondary energy limited to secondary market.

(6) Canadian system (Mica and Revelstoke) 30-year average generation minus firm energy capability.

TABLE 2

MICA PROJECT OPERATING CRITERIA
ALTERNATIVE OPERATING PLAN

Month	End of Previous Period Arrow Storage Content (ksfd)	Target Operation: Period Average Outflow (cfs)	Target Operation: End-of-Period Treaty Content(1) (ksfd)	Minimum Outflow (cfs)	Minimum Treaty Content(2) (ksfd)
August 1-15	3 300 - FULL	-	3 456.2	10 000	0.0
	0 - 3 300	27 000			
August 16-31	2 400 - FULL	-	3 529.2	10 000	0.0
	0 - 2 400	27 000			
September	2 500 - FULL	-	3 529.2	10 000	0.0
	0 - 2 500	27 000			
October	2 900 - FULL	-	3 529.2	10 000	0.0
	0 - 2 900	27 000			
November	3 400 - FULL	14 000	-	10 000	0.0
	3 000 - 3 400	23 000			
	0 - 3 000	27 000			
December	3 200 - FULL	22 000	-	15 000	756.2
	2 200 - 3 200	27 000			
	0 - 2 200	34 000			
January	1 700 - FULL	27 000	-	15 000	356.2
	0 - 1 700	34 000			
February	700 - FULL	25 000	-	15 000	0.0
	0 - 700	27 000			
March	500 - FULL	24 000	-	15 000	0.0
	0 - 500	27 000			
April 1-15	0 - FULL	22 000	-	15 000	0.0
April 16-30	0 - FULL	15 000	-	10 000	0.0
May	200 - FULL	12 000	-	10 000	0.0
	0 - 200	20 000			
June	500 - FULL	10 000	-	10 000	0.0
	0 - 500	20 000			
July	2 300 - FULL	-	3 256.2	10 000	0.0
	0 - 2 300	27 000			

Notes: (1) A maximum outflow of 34000 cfs will apply if the target end-of-period storage content is less than 3529.2 ksfd.

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

COLUMBIA RIVER TREATY
CRITICAL RULE CURVES
END OF MONTH CONTENTS IN KSFD
1993-94 OPERATING YEAR

TABLE 3

MICA

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3529.2	3529.2	3529.2	3428.4	3157.5	2614.0	2210.3	1532.9	1149.3	344.4	176.1	355.1	1907.1	2863.5
2ND YR	3389.2	3529.2	3529.2	3428.4	2740.8	2016.1	1259.9	637.5	18.4	0.0	0.0	369.0	1502.5	2624.2
3RD YR	2999.9	3468.2	3529.2	2966.2	2313.5	1587.7	840.0	213.8	0.0	0.0	0.0	150.0	1349.2	2253.5
4TH YR	2468.3	2626.8	2585.4	2095.2	1530.5	756.2	356.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0

ARROW

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3579.6	3579.6	3575.1	3446.6	3367.6	3056.4	1975.6	1148.3	1010.7	869.0	562.6	1478.7	3107.7	3345.6
2ND YR	3332.7	3087.9	3036.0	2644.0	2515.8	2383.1	1216.9	624.8	443.9	413.9	520.9	249.7	1505.3	2961.0
3RD YR	3208.6	2877.0	2874.4	2983.6	2963.2	2408.9	1452.1	531.9	53.2	60.0	35.0	457.4	983.3	1484.2
4TH YR	1398.1	1078.3	1111.8	980.3	340.0	27.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

DUNCAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	705.8	705.8	705.8	705.8	705.8	504.1	260.9	128.7	59.5	37.9	1.1	118.6	392.7	563.9
2ND YR	479.1	492.6	430.5	202.6	23.6	0.0	0.0	0.1	0.0	0.0	23.3	72.6	100.3	145.6
3RD YR	108.1	160.9	199.3	60.8	0.2	0.2	0.0	0.7	0.0	0.0	0.9	131.8	75.6	15.6
4TH YR	0.0	0.0	0.7	0.3	0.6	0.2	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COMPOSITE

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	7814.6	7814.6	7810.1	7580.8	7230.9	6174.5	4446.8	2809.9	2219.5	1251.3	739.8	1952.4	5407.5	6773.0
2ND YR	7201.0	7109.7	6995.7	6275.0	5280.2	4399.2	2476.8	1262.4	462.3	413.9	544.2	691.3	3108.1	5730.8
3RD YR	6316.6	6506.1	6602.9	6010.6	5276.9	3996.8	2292.1	746.4	53.2	60.0	35.9	739.2	2408.1	3753.3
4TH YR	3866.4	3705.1	3697.9	3075.8	1871.1	783.4	359.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COLUMBIA RIVER TREATY
ASSURED REFILL CURVES
END OF MONTH CONTENTS IN KSFD
1993-94 OPERATING YEAR

TABLE 4

MICA

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1640.0	2220.3	2826.8	3007.9	3075.1	3093.3	3089.6	2603.5	2084.3	1825.1	1604.2	1696.6	2655.9	3529.2

ARROW

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
0.0	0.0	0.0	0.0	0.0	0.0	0.0	406.5	1010.5	1055.6	1209.6	1983.2	3107.7	3579.6

DUNCAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
55.9	126.8	193.1	223.8	241.3	252.5	262.7	263.5	268.3	277.0	261.7	360.0	540.9	705.8

DUNCAN VARIABLE REFILL CURVE (KSFD) TABLE 5

1993-94 OPERATING YEAR

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							474.2	438.2	431.6	445.8	466.8	446.2	594.0	705.8
1929-30							472.2	436.2	429.3	443.3	477.2	467.1	605.4	,,
1930-31							416.8	382.0	378.6	399.3	428.6	415.5	594.0	,,
1931-32							1.2	1.6	0.8	0.0	35.6	112.3	447.9	,,
1932-33							,,	,,	,,	,,	0.0	0.0	314.3	,,
1933-34							,,	,,	,,	,,	45.9	144.5	488.3	,,
1934-35							37.4	13.6	28.2	59.2	123.0	179.7	454.5	,,
1935-36							42.2	17.3	19.5	49.4	113.1	185.2	506.0	,,
1936-37							420.3	385.5	380.7	396.6	421.0	407.6	576.2	,,
1937-38							1.2	1.6	0.8	16.2	91.5	168.0	471.8	,,
1938-39							271.7	239.9	238.5	263.4	309.1	326.7	577.0	,,
1939-40							260.3	228.4	234.3	268.8	315.5	328.8	565.7	,,
1940-41							340.0	306.8	308.9	341.9	391.6	406.7	589.1	,,
1941-42							158.8	132.4	141.9	169.9	227.9	280.9	522.6	,,
1942-43							121.4	96.5	105.7	131.9	199.9	280.8	505.0	,,
1943-44							496.5	459.7	457.9	473.1	494.2	479.6	624.0	,,
1944-45							417.5	382.7	381.8	400.0	423.7	408.0	582.4	,,
1945-46							1.2	1.6	0.8	0.0	0.0	56.8	440.9	,,
1946-47							,,	,,	,,	,,	9.3	100.4	453.6	,,
1947-48							,,	,,	,,	,,	43.8	118.7	464.5	,,
1948-49							173.8	147.8	153.6	175.7	233.2	294.2	565.4	,,
1949-50							1.2	1.6	0.8	0.0	61.4	126.9	408.6	,,
1950-51							,,	,,	,,	,,	11.1	92.4	439.6	,,
1951-52							5.5	,,	,,	24.4	95.7	178.3	484.5	,,
1952-53							4.9	,,	,,	23.7	93.2	156.5	450.9	,,
1953-54							1.2	,,	,,	0.0	0.0	18.9	381.9	,,
1954-55							,,	,,	,,	,,	41.5	106.2	386.2	,,
1955-56							,,	,,	,,	,,	0.0	66.8	437.5	,,
1956-57							,,	,,	,,	,,	48.2	119.6	501.4	,,
1957-58							,,	,,	,,	,,	0.0	57.2	453.6	,,

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ECC LOWER LIMIT		1.2	1.6	0.8					
POWER DISCHARGE REQUIREMENTS IN CFS	80 MAF--	100	400	400	400	2000	2000	2000	2000
FOR JANUARY THROUGH JULY	90 MAF--	100	100	100	100	100	100	100	100
VOLUME RUNOFF AT THE DALLES	95 MAF--	100	100	100	100	100	100	100	100

ARROW VARIABLE REFILL CURVE (KSFD)
1993-94 OPERATING YEAR

TABLE 6

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							2235.7	2595.8	3004.8	3257.9	3579.6	3314.2	3579.6	3579.6
1929-30							627.2	1024.9	1526.5	1887.8	2809.8	2753.2	3422.4	,,
1930-31							1025.1	1419.1	1859.5	2193.8	2963.0	2572.4	3421.5	,,
1931-32							627.2	246.2	183.3	0.0	222.4	1110.8	2641.3	,,
1932-33							,,	,,	,,	,,	549.2	1292.5	2592.7	,,
1933-34							,,	,,	,,	,,	619.8	1718.5	3120.3	,,
1934-35							,,	,,	,,	,,	555.1	1097.1	2546.6	,,
1935-36							,,	,,	,,	28.0	623.5	1290.5	2870.2	,,
1936-37							2524.7	2876.7	3283.6	3484.2	3579.6	3501.1	3579.6	,,
1937-38							627.2	246.2	183.3	333.8	1053.3	1755.8	2973.7	,,
1938-39							835.9	1235.2	1685.3	2027.2	2883.9	2671.0	3579.6	,,
1939-40							627.2	765.5	1289.1	1753.9	2692.4	2468.6	3497.4	,,
1940-41							1731.5	2105.8	2580.4	2985.1	3579.6	3574.9	3579.6	,,
1941-42							627.2	624.3	725.5	908.6	1434.5	1817.3	2925.8	,,
1942-43							1120.5	1130.4	1093.3	1336.0	2378.7	2993.1	3412.7	,,
1943-44							3110.5	3441.3	3579.6	3579.6	3579.6	3579.6	3579.6	,,
1944-45							2491.9	2844.9	3308.5	3564.7	,,	3528.9	,,	,,
1945-46							627.2	246.2	183.3	0.0	528.3	1318.3	2794.7	,,
1946-47							,,	,,	,,	116.6	891.8	1663.8	2936.9	,,
1947-48							,,	,,	,,	0.0	656.7	1378.1	2785.1	,,
1948-49							,,	,,	478.9	1058.5	2097.3	2704.1	3579.6	,,
1949-50							,,	,,	183.3	0.0	630.1	1295.3	2478.8	,,
1950-51							,,	,,	,,	184.2	938.1	1628.2	3063.6	,,
1951-52							,,	,,	,,	176.5	970.9	1774.8	3169.6	,,
1952-53							,,	332.8	332.6	552.5	1557.4	2052.5	3129.2	,,
1953-54							,,	246.2	183.3	0.0	309.8	1013.0	2474.3	,,
1954-55							,,	,,	,,	,,	568.3	1172.2	2380.3	,,
1955-56							,,	,,	,,	,,	461.0	1342.8	2822.1	,,
1956-57							,,	,,	,,	,,	458.3	1177.4	3255.1	,,
1957-58							,,	,,	,,	,,	488.1	1228.8	2941.6	,,
ECC LOWER LIMIT							627.2	246.2	183.3					
POWER DISCHARGE REQUIREMENTS IN CFS						80 MAF--	5000	5000	5000	25000	25000	40000	45000	45000
FOR JANUARY THROUGH JULY						90 MAF--	5000	5000	5000	5000	5000	5000	5000	5000
VOLUME RUNOFF AT THE DALLES						95 MAF--	5000	5000	5000	5000	5000	10000	35000	35000

MICA VARIABLE REFILL CURVE (KSFD)
1993-94 OPERATING YEAR

TABLE 7

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							3529.2	3529.2	3389.8	3225.4	3157.3	2635.9	3089.1	3529.2
1929-30							3480.9	2887.5	2313.6	2202.0	2299.9	2017.2	2808.0	,,
1930-31							3529.2	3156.3	2578.2	2436.8	2460.4	2037.6	2882.3	,,
1931-32							1042.5	925.8	880.8	1039.4	1281.0	1404.9	2671.0	,,
1932-33							977.8	865.4	837.7	995.7	1215.1	1300.0	2509.3	,,
1933-34							317.6	66.4	32.4	230.8	573.0	1043.3	2759.3	,,
1934-35							357.4	159.4	55.4	176.2	429.5	574.6	2035.5	,,
1935-36							996.4	685.8	451.3	495.4	721.5	862.2	2467.0	,,
1936-37							3529.2	3529.2	3342.8	3169.4	3148.6	2649.9	3121.2	,,
1937-38							1340.8	1220.7	1176.1	1329.4	1543.1	1632.2	2761.6	,,
1938-39							3529.2	3029.4	2465.1	2352.6	2400.2	2061.6	3112.8	,,
1939-40							3382.7	2771.8	2224.6	2113.9	2192.4	1852.4	2875.1	,,
1940-41							3529.2	3360.5	2802.2	2672.4	2761.2	2421.7	3102.9	,,
1941-42							1030.6	802.5	652.8	718.8	939.9	1063.8	2392.9	,,
1942-43							1969.7	1836.4	1794.2	1918.2	2151.4	2271.6	2997.7	,,
1943-44							3529.2	3529.2	3448.2	3274.5	3228.8	2758.1	3258.3	,,
1944-45							,,	,,	3421.9	3265.1	3202.6	2684.1	3178.3	,,
1945-46							716.1	609.2	562.3	719.3	967.8	1095.3	2665.5	,,
1946-47							893.5	782.8	764.9	936.3	1194.8	1365.6	2735.3	,,
1947-48							818.6	706.6	673.6	822.6	1054.5	1153.7	2622.3	,,
1948-49							2529.5	2384.5	2326.2	2432.5	2566.8	2558.4	3387.0	,,
1949-50							1141.0	1025.1	968.5	1112.6	1331.5	1380.4	2435.9	,,
1950-51							1182.7	1065.9	1041.5	1200.2	1440.5	1503.1	2794.2	,,
1951-52							1554.4	1426.9	1377.4	1502.5	1695.6	1801.0	2939.5	,,
1952-53							1858.1	1727.1	1687.4	1814.8	1969.5	1959.5	2906.3	,,
1953-54							720.1	613.1	597.0	765.9	1004.5	1068.5	2408.3	,,
1954-55							1111.7	987.9	964.4	1114.5	1339.1	1409.7	2418.5	,,
1955-56							1039.9	923.2	878.4	1027.8	1255.3	1399.1	2710.0	,,
1956-57							1202.4	1085.2	1055.3	1210.7	1428.0	1487.1	3036.7	,,
1957-58							1047.7	933.8	910.1	1075.8	1315.6	1384.0	2802.7	,,
ECC LOWER LIMIT							317.6	0.0	0.0					

POWER DISCHARGE REQUIREMENTS IN CFS FOR JANUARY THROUGH JULY VOLUME RUNOFF AT THE DALLES		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
	80 MAF--	3000	20000	20000	22000	22000	25000	28000	28000
	90 MAF--	3000	3000	3000	3000	3000	3000	3000	3000
	95 MAF--	3000	3000	3000	3000	10000	10000	20000	25000

TABLE 8

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
1993-94 OPERATING YEAR
KSFD

	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	323.7	231.4	288.9	283.4	298.0	403.6	560.8	705.8
1929-30	,,	,,	,,	,,	,,	,,	323.2	218.3	206.2	242.8	258.9	368.8	529.4	,,
1930-31	,,	,,	,,	,,	,,	,,	361.9	221.3	245.5	249.3	265.1	392.3	558.2	,,
1931-32	,,	,,	,,	,,	,,	,,	277.3	65.5	65.5	80.9	109.1	281.3	609.8	,,
1932-33	,,	,,	,,	,,	,,	,,	273.7	,,	,,	75.1	94.3	191.7	573.3	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	65.5	127.0	339.6	606.4	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	83.5	187.2	488.1	,,
1935-36	,,	,,	,,	,,	,,	,,	333.6	179.5	162.8	152.2	194.1	406.1	705.8	,,
1936-37	,,	,,	,,	,,	,,	,,	379.9	292.4	201.6	243.3	259.4	353.2	540.8	,,
1937-38	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	77.1	83.5	217.3	542.6	,,
1938-39	,,	,,	,,	,,	,,	,,	,,	,,	,,	82.8	107.2	408.8	705.8	,,
1939-40	,,	,,	,,	,,	,,	,,	277.3	126.0	102.3	198.9	219.6	450.7	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	287.2	120.0	147.7	248.3	264.2	394.8	536.5	,,
1941-42	,,	,,	,,	,,	,,	,,	273.7	85.2	136.6	277.6	295.9	503.4	705.8	,,
1942-43	,,	,,	,,	,,	,,	,,	275.0	78.1	92.7	86.1	121.1	200.0	644.2	,,
1943-44	,,	,,	,,	,,	,,	,,	340.3	222.8	266.7	273.0	288.0	403.9	554.6	,,
1944-45	,,	,,	,,	,,	,,	,,	328.5	174.9	163.8	102.1	103.3	409.6	705.8	,,
1945-46	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	75.7	95.6	322.3	647.5	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	102.0	314.0	629.6	,,
1947-48	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	65.5	300.5	705.8	,,
1948-49	,,	,,	,,	,,	,,	,,	273.7	116.9	,,	73.8	102.0	330.1	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	65.5	,,	65.5	65.5	184.0	525.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	285.1	534.2	,,
1951-52	,,	,,	,,	,,	,,	,,	277.3	,,	,,	,,	67.4	92.4	255.0	,,
1952-53	,,	,,	,,	,,	,,	,,	357.6	127.0	125.5	101.9	114.1	244.2	525.1	,,
1953-54	,,	,,	,,	,,	,,	,,	307.4	65.5	65.5	73.2	84.1	237.1	547.6	,,
1954-55	,,	,,	,,	,,	,,	,,	303.4	178.9	185.0	116.8	125.2	154.5	488.8	,,
1955-56	,,	,,	,,	,,	,,	,,	277.3	65.5	65.5	65.5	84.7	266.6	585.4	,,
1956-57	,,	,,	,,	,,	,,	,,	273.7	73.1	,,	74.5	89.9	376.1	655.8	,,
1957-58	,,	,,	,,	,,	,,	,,	282.5	84.7	,,	77.1	96.3	359.4	705.8	,,

TABLE 9

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
1993-94 OPERATING YEAR
KSFD

	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	2688.8	2713.2	3075.4	3088.5	3111.2	3235.8	3579.6	3579.6
1929-30	,,	,,	,,	,,	,,	,,	2416.9	2375.0	1812.6	2012.0	2084.4	2448.6	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	2844.6	3047.5	3075.4	3088.5	3111.2	3235.8	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2371.6	1712.7	1008.4	1016.1	1126.6	2224.6	,,	,,
1932-33	,,	,,	,,	,,	,,	,,	2363.6	1720.2	,,	1008.4	1036.6	1761.7	3034.5	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1784.9	2327.4	3579.6	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1725.7	3034.5	,,
1935-36	,,	,,	,,	,,	,,	,,	2949.5	2236.7	,,	1070.1	1373.5	2186.4	3579.6	,,
1936-37	,,	,,	,,	,,	,,	,,	2980.2	3075.4	2118.4	2774.9	2819.5	3042.6	,,	,,
1937-38	,,	,,	,,	,,	,,	,,	2363.6	1720.2	1008.4	1082.9	1278.3	1831.2	3147.6	,,
1938-39	,,	,,	,,	,,	,,	,,	,,	,,	,,	1100.9	1265.5	2471.7	3579.6	,,
1939-40	,,	,,	,,	,,	,,	,,	2371.6	2061.7	,,	1162.3	1336.7	2294.0	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	2363.6	1720.2	1811.3	3088.5	3111.2	3235.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	2535.4	2570.7	2993.2	,,	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	1111.2	1322.0	1440.3	2389.1	,,
1943-44	,,	,,	,,	,,	,,	,,	2850.2	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	,,
1944-45	,,	,,	,,	,,	,,	,,	2598.7	2577.0	2036.2	1603.7	1677.8	2301.7	3289.4	,,
1945-46	,,	,,	,,	,,	,,	,,	2363.6	1720.2	1008.4	1072.6	1242.3	2201.4	3579.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1360.6	2147.4	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1036.6	1183.2	2216.8	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	2363.6	1720.2	,,	1144.6	1376.0	2494.5	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1008.4	1113.8	2232.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1355.5	3337.9	,,
1951-52	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1345.2	1792.6	3013.9	,,
1952-53	,,	,,	,,	,,	,,	,,	3000.1	1720.2	,,	1057.2	1172.9	1476.3	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	2363.6	,,	,,	,,	1134.3	1628.0	1898.0	,,
1954-55	,,	,,	,,	,,	,,	,,	2485.8	2641.5	2472.5	1262.6	1276.9	1653.7	3224.8	,,
1955-56	,,	,,	,,	,,	,,	,,	2371.6	1712.7	1008.4	1008.4	1216.6	1990.6	2993.4	,,
1956-57	,,	,,	,,	,,	,,	,,	2363.6	1720.2	,,	1077.8	1224.3	2651.4	3579.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	1046.9	1190.9	2242.6	,,	,,

MICA
FLOOD CONTROL STORAGE RESERVATION CURVES
1993-94 OPERATING YEAR
KSFD

TABLE 10

	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	3233.8	3201.6	3428.4	3428.4	3428.4	3457.3	3492.7	3529.2
1929-30	,,	,,	,,	,,	,,	,,	3124.0	3071.4	2809.2	2869.8	2869.8	3045.7	3221.7	,,
1930-31	,,	,,	,,	,,	,,	,,	3293.6	3332.9	3428.4	3416.9	3416.9	3457.3	3492.7	,,
1931-32	,,	,,	,,	,,	,,	,,	3105.7	2803.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1932-33	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1935-36	,,	,,	,,	,,	,,	,,	3334.6	3017.8	,,	,,	,,	2808.9	3212.6	,,
1936-37	,,	,,	,,	,,	,,	,,	3345.7	3378.0	2926.9	3171.1	3171.1	3191.9	3382.2	,,
1937-38	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1938-39	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	2853.9	3228.8	,,
1939-40	,,	,,	,,	,,	,,	,,	3105.7	2948.8	,,	2513.5	2513.5	2781.5	3188.8	,,
1940-41	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2808.7	3428.4	3428.4	3457.3	3431.4	,,
1941-42	,,	,,	,,	,,	,,	,,	,,	,,	2480.5	3078.2	3078.2	3249.2	3159.1	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	2480.5	2480.5	2781.5	3149.6	,,
1943-44	,,	,,	,,	,,	,,	,,	3296.2	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1944-45	,,	,,	,,	,,	,,	,,	3199.2	3149.2	2895.3	2716.9	2716.9	2938.9	3172.6	,,
1945-46	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1951-52	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1952-53	,,	,,	,,	,,	,,	,,	3353.3	2807.2	,,	,,	,,	,,	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	3101.7	,,	,,	,,	,,	,,	,,	,,
1954-55	,,	,,	,,	,,	,,	,,	3152.9	3174.0	3063.0	2560.7	2560.7	,,	,,	,,
1955-56	,,	,,	,,	,,	,,	,,	3105.7	2803.2	2480.5	2480.5	2480.5	2695.5	3172.6	,,
1956-57	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	2781.5	3149.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,

COLUMBIA RIVER TREATY
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS IN KSFD
1993-94 OPERATING YEAR

TABLE 11

FLOW YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7810.1	7580.8	7230.9	6653.8	5327.9	4015.3	3363.3	3157.7	3075.5	4039.8	6304.5	7814.6
1929-30	,,	,,	,,	,,	,,	,,	3979.5	3891.9	,,	,,	,,	,,	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	4377.4	4015.3	,,	,,	,,	,,	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	1670.9	1173.6	1064.9	1039.4	1539.0	2628.0	5745.1	,,
1932-33	,,	,,	,,	,,	,,	,,	1606.2	1113.2	1021.8	995.7	1764.3	2592.5	5416.3	,,
1933-34	,,	,,	,,	,,	,,	,,	946.0	314.2	216.5	230.8	1238.7	2906.3	6251.9	,,
1934-35	,,	,,	,,	,,	,,	,,	1022.0	419.2	266.9	235.4	1107.6	1851.4	5036.6	,,
1935-36	,,	,,	,,	,,	,,	,,	1665.8	949.3	654.1	572.8	1458.1	2337.9	5843.2	,,
1936-37	,,	,,	,,	,,	,,	,,	5327.9	4015.3	3363.3	3157.7	3075.5	4039.8	6304.5	,,
1937-38	,,	,,	,,	,,	,,	,,	1969.2	1468.5	1360.2	1679.4	2687.9	3556.0	6101.4	,,
1938-39	,,	,,	,,	,,	,,	,,	4188.2	3991.7	3333.5	3144.1	3075.5	4006.5	6304.5	,,
1939-40	,,	,,	,,	,,	,,	,,	3977.1	3597.4	3329.3	3149.5	,,	4008.6	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	5083.8	4015.3	3363.3	3157.7	,,	4039.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	1816.6	1559.2	1520.2	1797.3	2377.4	3162.0	5841.3	,,
1942-43	,,	,,	,,	,,	,,	,,	3211.6	3063.3	2910.6	3012.6	3013.7	3960.6	6268.6	,,
1943-44	,,	,,	,,	,,	,,	,,	5327.9	4015.3	3363.3	3157.7	3075.5	4039.8	6304.5	,,
1944-45	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1945-46	,,	,,	,,	,,	,,	,,	1344.5	857.0	746.4	719.3	1496.1	2470.4	5891.5	,,
1946-47	,,	,,	,,	,,	,,	,,	1521.9	1030.6	949.0	1052.9	2095.9	3129.8	6046.4	,,
1947-48	,,	,,	,,	,,	,,	,,	1447.0	954.4	857.7	822.6	1755.0	2650.5	5871.9	,,
1948-49	,,	,,	,,	,,	,,	,,	3330.5	2778.5	2716.8	3056.4	3047.0	3974.0	6304.5	,,
1949-50	,,	,,	,,	,,	,,	,,	1769.4	1272.9	1152.6	1112.6	2023.0	2802.6	5323.3	,,
1950-51	,,	,,	,,	,,	,,	,,	1811.1	1313.7	1225.6	1384.4	2389.7	3223.7	6159.1	,,
1951-52	,,	,,	,,	,,	,,	,,	2187.1	1674.7	1561.5	1703.4	2670.8	3649.7	6248.1	,,
1952-53	,,	,,	,,	,,	,,	,,	2490.2	2061.5	2020.8	2391.0	2907.0	3836.3	6214.5	,,
1953-54	,,	,,	,,	,,	,,	,,	1348.5	860.9	781.1	765.9	1314.3	2100.4	5264.5	,,
1954-55	,,	,,	,,	,,	,,	,,	1740.1	1235.7	1148.5	1114.5	1948.9	2688.1	5185.0	,,
1955-56	,,	,,	,,	,,	,,	,,	1668.3	1171.0	1062.5	1027.8	1716.3	2808.7	5915.5	,,
1956-57	,,	,,	,,	,,	,,	,,	1830.8	1333.0	1239.4	1210.7	1934.5	2784.1	6265.0	,,
1957-58	,,	,,	,,	,,	,,	,,	1676.1	1181.6	1094.2	1075.8	1803.7	2670.0	6051.1	,,

DETERMINATION OF DOWNSTREAM POWER BENEFITS
FOR THE ALTERNATIVE OPERATING PLAN
FOR OPERATING YEAR 1993-94

DETERMINATION OF DOWNSTREAM POWER BENEFITS
FOR THE ALTERNATIVE OPERATING PLAN
FOR OPERATING YEAR 1993-94

July 1989

1. Introduction

In accordance with the Entity Agreements on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 28 July 1988 and 12 August 1988 respectively, the Entities have prepared an Alternative Operating Plan without firm energy shifting. The United States Entity has determined that this Alternative Operating Plan is not part of the optimum United States operation. Therefore, in accordance with Section 3 of the Agreement on Principles, this Alternative Operating Plan has not been adopted for the Assured Operating Plan. However, at the discretion of the United States Entity, the operating rule curves and associated operating rules contained in this Alternative Operating Plan may be adopted for inclusion in the Detailed Operating Plan. A decision by the U.S. Entity to adopt this operation for the Detailed Operating Plan will not change the obligation of the U.S. Entity to deliver to the Canadian Entity an amount of power equal to the increase in the purchased portion of the Canadian Entitlement resulting from energy shifting, since firm energy shifting was included in the Assured Operating Plan. This document defines the downstream benefits that are associated with the Alternative Operating Plan. This Alternative Downstream Benefit (DSB) study was prepared in accordance with the same procedures described in the Determination of Downstream Power Benefits document for 1993-94, except as noted in the Alternative Operating Plan and Section 6 below.

2. Results of Canadian Entitlement Computations

For the Alternative Operative Plan 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 1):

Dependable Capacity = 1,273.4 MW
Average Annual Energy = 635.9 MW

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 1993-94 operating year are based on the formula X - (Y - Z), where the quantities X, Y, and Z are defined in POP. The quantity X is derived from the difference between last year's Assured Operating Plan studies 93-42 and 93-13 and the quantity Y is derived from the difference between last year's Assured Operating Plan studies 93-12 and 93-13. These computations are set out in the 1992-93 agreement. 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, was computed to be (See Table 1):

Dependable Capacity = 1,251.8 MW
Average Annual Energy = 622.5 MW

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

Dependable Capacity = 1,476.9 - (1,476.9 - 1,251.8) = 1,251.8 MW
Average Annual Energy = 593.7 - (592.3 - 622.5) = 623.9 MW

The computed Canadian Entitlement exceeds these amounts.

4. Effect on Sale of Canadian Entitlement

The Canadian Entitlement to downstream power benefits for operating year 1993-94 was sold to the United States of America under the Canadian Entitlement Purchase Agreement dated 13 August 1964. The studies developed for this sale included the assumption of operation of Treaty storage for optimum power generation downstream in the United States of America only. The Canadian Entitlement determined from the 1993-94 Alternative Operating Plan for this condition would have been:

Dependable Capacity = 1,276.5 MW
Average Annual Energy = 634.5 MW

Since the 1993-94 Alternative Operating Plan was in fact 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 with the Canadian Entitlement to downstream power benefits shown above indicates an increase in Canadian Entitlement of 1.4 MW of average annual usable energy, and a decrease of 3.1 MW in dependable capacity.

Since this Alternative Operating Plan is not being adopted for the Assured Operating Plan, the quantities shown in the above paragraph are not involved in the power transfers described in Sections 7 and 10 of the Canadian Entitlement Purchase Agreement, dated 13 August 1964.

5. Summary of Canadian Entitlement Computations

The following Tables and Chart summarize the study results:

Table 1. Computation of Canadian Entitlement For 1993-94 Alternative 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 2. Summary of Power Regulations from 1993-94 Alternative Operating Plan for the Computation of Canadian Entitlement to Downstream Power Benefits

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system.

Table 3. Determination of Loads for 1993-94 Step I, II, and III Studies for Alternative Operating Plan

This table shows the computation of the Step I, II, and III loads. The monthly loads for Step II and III studies have the same ratio between each month and the annual average as the Pacific Northwest (PNW) area load. The PNW area firm loads on this table were based on the current forecast data. 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 POP.

Table 4. Determination of Displaceable Thermal Market for 1993-94 Alternative Operating Plan

This table shows the computation of the potential thermal displacement market for the downstream power benefit determination of usable energy. The potential thermal displacement market was limited to the existing and scheduled thermal energy capability after allowance for reserves and minimum thermal generation, and reductions for the thermal resources used outside the PNW Area.

Table 5. Comparison of 1993-94 Alternative Operating Plan and Recent Assured Operating Plans

Table 6. Comparison of 1993-94 Alternative DSB Study to Recent DDPB Studies

Tables 5 and 6 tabulate various data from the five most recent studies.

Chart 1. 1993-94 Determination of Downstream Power Benefits 30-Year 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.

6. Summary of Changes From 1993-94 Assured Operating Plan

Pursuant to the July 28, 1988 Entity Agreement on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, there were several changes in the 1993-94 Alternative studies when compared to previous studies. (See Section 6 of the 1993-94 Assured Operating Plan.) An explanation of the more important changes compared to the Assured Operating Plan is given below.

(a) Loads and Resources

In order to cover a 209 MW annual average firm deficit in the region a resource acquisition was added. Based on expected resource additions for this size of deficit, the resources were assumed to be approximately 128 MW of conservation and the remainder small hydro.

In this Alternative Operating Plan, there was no shifting of firm energy load carrying capability.

(b) Downstream Power Benefit Computation

The potential displaceable thermal market was decreased by a uniform amount equal to the amount of thermal power being used to meet loads outside the PNW area. The components of the exports out of the region are shown in Table 4. Only the amount of the seasonal exchange exports, not balanced by corresponding imports, was included in the net export amount.

The inclusion of the shifted firm energy load carrying capability in the Assured Operating Plan resulted in an increase in Canadian Entitlement of 19.8 MW of average annual usable energy and a decrease of 6.9 MW of dependable capacity.

TABLE 1

COMPUTATION OF CANADIAN ENTITLEMENT FOR
1993-94 ALTERNATIVE OPERATING PLAN:

A. Optimum Power Generation in Canada and the U.S. (From 94-42)
B. Optimum Power Generation in the U.S. Only (From 94-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 94-22)

Determination of Dependable Capacity Credited to Canadian Storage - MW

	(A)	(B)	(C)
Step II - Critical Period Avg. Generation 1/	8,879.5	8,883.9	8,848.1
Step III - Critical Period Avg. Generation 2/	7,036.3	7,036.3	7,036.3
Gain Due to Canadian Storage	1,843.2	1,847.6	1,811.8
Average Critical Period Load Factor in % 3/	72.37	72.37	72.37
Dependable Capacity Gain 4/	2,546.9	2,553.0	2,503.5
Canadian Share of Dependable Capacity 5/	1,273.4	1,276.5	1,251.8

Determination of Increase in Average Annual Usable Energy - Average MW

Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8,839.6	8,844.0	8,808.6
Thermal Replacement Energy 7/	1,366.4	1,351.0	1,352.3
Other Usable Secondary Energy 8/	461.5	469.7	479.8
System Annual Average Usable Energy	10,667.5	10,664.7	10,640.7
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6,485.2	6,485.2	6,485.2
Thermal Replacement Energy 7/	1,943.1	1,943.1	1,943.1
Other Usable Secondary Energy 8/	967.4	967.4	967.4
System Annual Average Usable Energy	9,395.7	9,395.7	9,395.7
Average Annual Usable Energy Gain 9/	1,271.8	1,269.0	1,245.0
Canadian Share of Avg. Annual Energy Gain 5/	635.9	634.5	622.5

1/ Step II values were obtained from the 94-42, 94-12, and 94-22 studies, respectively.
2/ Step III values were obtained from the 94-13 study.
3/ Critical period load factor from Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ One-half of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load.
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 2

SUMMARY OF POWER REGULATIONS
FROM 1993-94 ALTERNATIVE OPERATING PLAN

	BASIC DATA		STEP I			STEP II				STEP III			
PROJECTS	NUMBER OF UNITS	NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	30 YEAR AVERAGE ANNUAL GENERATION MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	30 YEAR AVERAGE ANNUAL GENERATION MW
HYDRO RESOURCES													
CANADIAN													
Mica			7,000			7,000							
Arrow			7,100			7,100							
Duncan			1,400			1,400							
Subtotal			15,500			15,500							
BASE SYSTEM													
Hungry Horse	4	328	3,161	328	102	3,008	196	113	103	3,008	328	218	103
Kerr	3	160	1,219	149	113	1,219	152	103	117	1,219	152	142	115
Thompson Falls	6	40		40	38		40	39	37		40	40	36
Noxon Rapids	5	554	231	536	149		554	134	203		554	171	203
Cabinet Gorge	4	225		230	100		230	87	117		230	107	117
Albeni Falls	3	49	1,155	25	25	1,155	24	24	24	1,155	22	19	23
Box Canyon	4	74		72	46		71	44	48		70	55	47
Grand Coulee	24	6,684	5,185	6,382	2,014	5,072	6,360	1,787	2,317	5,072	5,776	1,209	2,254
Chief Joseph	27	2,687		2,687	1,123		2,687	1,026	1,378		2,687	747	1,306
Wells	10	820		820	391		820	366	452		820	271	419
Rocky Reach	11	1,267		1,267	562		1,267	526	677		1,267	390	634
Rock Island	18	544		544	273		544	257	323		544	187	295
Wanapum	10	986		986	502		986	477	591		986	343	533
Priest Rapids	10	912		912	499		912	473	566		912	348	510
Brownlee	5	675	975	675	211	974	675	277	277	974	675	271	277
Oxbow	4	220		220	87		220	112	114		220	112	114
Ice Harbor	6	693		693	212		693	225	296		693	175	295
McNary	14	1,127		1,127	628		1,124	585	752		1,124	452	701
John Day	16	2,484	535	2,484	925		2,484	928	1,265		2,484	711	1,219
The Dalles	22+2F	2,076		2,076	734		2,076	713	976		2,076	564	953
Bonneville	18+2F	1,147		1,147	557		1,147	547	682		1,147	454	650
Kootenay Lake			673			673				673			
Chelan	2	54	677	51	38	676	51	38	45	676	51	51	42
Coeur d'Alene Lake			223			223				223			
Total Base System Hydro		23,806	29,535	23,451	9,329	28,500	23,313	8,881	11,360	13,000	22,858	7,037	10,846
ADDITIONAL STEP I PROJECTS													
Libby	5	604	4,980	528	191								
Boundary	6	1,055		855	369								
Spokane River Plants	24	157	104	155	91								
Hells Canyon	3	450		421	170								
Dworshak	3	460	2,015	460	181								
Lower Granite	6	930		930	210								
Little Goose	6	930		930	211								
Lower Monumental	6	930		930	199								
Pelton, Rereg., and Round Butte	7	423	274	418	126								
Subtotal		5,939	7,373	5,627	1,748								
THERMAL RESOURCES 1/													
Small Existing Thermal Plants				1,656	334								
Centralia #1 & #2				1,280	1,103								
Jim Bridger #1, #2, #3, & #4				2,003	1,649								
Colstrip #1,#2,#3,#4				1,310	978								
Trojan				1,104	804								
Boardman				530	405								
Valmy				242	195								
WNP #2				1,095	788								
Total Thermal Resources				9,220	6,256		9,218	6,305			9,218	6,574	
RESERVES 2/				(2,394)	0		(1,954)	0			(1,647)	0	
TOTAL RESOURCES				35,904	17,333		30,577	15,186			30,429	13,611	
LOADS													
ESTIMATED LOAD PACIFIC NORTHWEST AREA 3/				29,936	18,486		24,430	15,186			20,593	13,611	
Firm Exports				1413	960								
Surplus Firm Exports				0	219								
Firm Imports				(682)	(170)								
Miscellaneous Contracts				(169)	(131)								
Other Coordinated Hydro		3,188	5,486	(2,667)	(1,031)								
Independent Hydro Resources		1,963	4,342	(1,481)	(803)								
Estimated Hydro Maintenance				1,548	12								
Added Cons./Resources				0	(209)								
TOTAL STEP I LOADS				27,898	17,333								
SURPLUS				8,006	0		6,147	0			9,836	0	
CRITICAL PERIOD Starts				September 1, 1928			September 1, 1943				November 1, 1936		
Ends				February 29, 1932			April 30, 1945				April 15, 1937		
Length (Months)				42 Months			20 Months				5.5 Months		
Study Identification				94-41			94-42				94-13		

1/ Thermal energy capabilities are based on an annual plant factor of 60 percent the first full year of operation and 75 percent thereafter unless specified differently by project owner. These annual plant factors include deductions for energy resources and scheduled maintenance.
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 II or III Peak Load is equal to the Step II or III Annual Average Load, multiplied by the ratio of the PNW area Jan. Peak Load to the Annual Average Load.

TABLE 3

DETERMINATION OF LOADS FOR
1993-94 STEP I, II, AND III STUDIES
FOR ALTERNATIVE OPERATING PLAN

	LOAD OF THE PACIFIC NORTHWEST AREA				STEP I STUDY					STEP II STUDY		STEP III STUDY		
					ENERGY LOAD		PEAK LOAD							
Period	PNW Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Firm Surplus aMW	Total MWa 2/	Firm Surplus MW	Total MW	Thermal Installations 3/ aMW	Total Load 4/ aMW	Hydro Load 5/ aMW	Total Load 4/ aMW	Hydro Load 5/ aMW	Period
Aug. 1-15	17004	92.56	22051	77.11	0	17004	0	22051	6804	13876.4	7072.4	11697.0	4893.0	Aug. 1-15
Aug. 16-31	16925	92.13	22006	76.91	0	16925	0	22006	6804	13812.0	7008.0	11642.7	4838.7	Aug. 16-31
Sept. 1-15	16602	90.38	22713	73.09	0	16602	0	22713	6849	13548.4	6699.4	11420.5	4571.5	Sept. 1-15
Sept. 16-30	16562	90.16	22622	73.21	0	16562	0	22622	6849	13515.7	6666.7	11393.0	4544.0	Sept. 16-30
October	17338	94.38	24812	69.88	0	17338	0	24812	6885	14149.0	7264.0	11926.8	5041.8	October
November	19126	104.11	27010	70.81	0	19126	0	27010	6926	15608.1	8682.1	13156.8	6230.8	November
December	20716	112.77	28938	71.59	0	20716	0	28938	6920	16905.7	9985.7	14250.5	7330.5	December
January	21181	115.30	29936	70.75	0	21181	0	29936	6928	17285.1	10357.1	14570.4	7642.4	January
February	20151	109.69	28473	70.77	0	20151	0	28473	6775	16444.6	9669.6	13861.9	7086.9	February
March	18738	102.00	26272	71.32	0	18738	0	26272	6018	15291.5	9273.5	12889.9	6871.9	March
April 1-15	17782	96.80	24843	71.58	0	17782	0	24843	5200	14511.3	9311.3	12232.2	7032.2	April 1-15
April 16-30	17879	97.33	24925	71.73	0	17879	0	24925	4716	14590.5	9874.5	12298.9	7582.9	April 16-30
May	17229	93.79	23953	71.93	3000	20229	4858	28811	3394	14060.0	10666.0	11851.8	8457.8	May
June	17317	94.27	22881	75.68	0	17317	0	22881	4590	14131.9	9541.9	11912.3	7322.3	June
July	17357	94.49	22785	76.18	0	17357	0	22785	6797	14164.5	7367.5	11939.9	5142.9	July
Annual Average =	18370.1	100.00		72.57	254.8	18624.9			6152.1	14991.2	8839.1	12636.8	6484.7	Annual Avg.
Critical Period Avg =	18486.4			72.37	218.5	18704.9			6256.1	15184.2	8879.5	13610.6	7036.3	Crit.Per.Avg.
Step II Crit. Per. Avg =	18606.5								6304.7					
Step III Crit. Per. Avg=	19785.7								6574.3	Input 6/=	8879.5	Input 6/=	7036.3	
											********		*********	
August 1-31	16964.5	92.35	22028.5	77.01	0	16965	0	22029	6804.0	13844.2	7040.2	11669.9	4865.9	Aug. 1-31
September 1-30	16582.0	90.27	22667.5	73.15	0	16582	0	22668	6849.0	13532.0	6683.0	11406.7	4557.7	Sept. 1-30
April 1-30	17830.5	97.06	24884.0	71.65	0	17831	0	24884	4958.0	14550.9	9592.9	12265.6	7307.6	Apr. 1-30

Notes:
1. The PNW Area load does not include the exports or firm deficit but does include pumping. The computation of the load shape for Step II/III studies used these loads.
2. Step I study loads also include exports which are shown on Table 4, Line 4.
3. The thermal installations include large thermal, combustion turbines and existing small thermal.
4. The total firm load for the Step II/III studies is computed to have the same shape as the load of the Pacific Northwest Area.
5. The hydro load is equal to the total load minus the Step I study thermal installations.
6. Input is the critical period average generation for the Step II/III hydro studies used to calculate the residual hydro loads.

TABLE 4

DETERMINATION OF DISPLACEABLE THERMAL MARKET
FOR 1993-94 ALTERNATIVE OPERATING PLAN

(Energy in Average MW)

	Aug 1-15	Aug 16-31	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	Apr 1-15	Apr 16-30	May	June	July	Annual Average
THERMAL RESOURCES															
1. Total Thermal Resources	6804.0	6804.0	6849.0	6885.0	6926.0	6920.0	6928.0	6775.0	6018.0	5200.0	4716.0	3394.0	4590.0	6797.0	6152.1
2. Minimum Thermal Generation	1964.0	1964.0	1778.0	1898.0	2191.0	2191.0	2191.0	2191.0	1814.0	1645.0	1401.0	1285.0	1275.0	1898.0	1848.8
3. Displaceable Thermal Resources	4840.0	4840.0	5071.0	4987.0	4735.0	4729.0	4737.0	4584.0	4204.0	3555.0	3315.0	2109.0	3315.0	4899.0	4303.3
SYSTEM SALES															
4. Total Exports/Incl Exchanges	1074.0	1074.0	1078.0	879.0	854.0	916.0	872.0	830.0	825.0	868.0	825.0	1050.0	1100.0	1284.0	968.5
5. Total Export Exchanges	196.0	196.0	196.0	0.0	25.0	50.0	50.0	25.0	0.0	0.0	0.0	0.0	196.0	196.0	78.0
6. Exports w/o Exchanges	878.0	878.0	882.0	879.0	829.0	866.0	822.0	805.0	825.0	868.0	825.0	1050.0	904.0	1088.0	890.5
7. Additional Net Exchange Exports	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
8. Net Exchanges/Exports	878.4	878.4	882.4	879.4	829.4	866.4	822.4	805.4	825.4	868.4	825.4	1050.4	904.4	1088.4	
9. Firm Surplus Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3000.0	0.0	0.0	
10. Total System Sales	878.4	878.4	882.4	879.4	829.4	866.4	822.4	805.4	825.4	868.4	825.4	4050.4	904.4	1088.4	1145.6
11. Uniform Average Annual System Sales	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	1145.6	
PNW THERMAL DISPLACEMENT MARKET =	3694.4	3694.4	3925.4	3841.4	3589.4	3583.4	3591.4	3438.4	3058.4	2409.4	2169.4	963.4	2169.4	3753.4	3157.6

NOTES:

Line 1 = Total Thermal Resources from the Step I study includes those located in the PNW and those not located in the PNW which meet Step I system load.
Line 2 = Minimum generation requirement for above resources.
Line 3 = Displaceable Thermal Resources from the Step I study. Line 1 minus line 2.
Line 4 = Total Exports Including Exchanges consists of all firm contract sales of energy exported to meet non-PNWA load.
Line 5 = These exports are balanced by corresponding seasonal exchange imports.
Line 6 = Sum of the Step I study firm contract sales of energy exported to meet non-PNWA Loads minus the exchanges. Line 4 minus line 5.
Line 7 = This is an additional export, the portion of the seasonal exchange contracts not balanced by a corresponding import.
Line 8 = Line 6 plus line 7.
Line 9 = Firm Surplus Energy Sales in the Step I Study assumed to be exported to PSW.
Line 10 = Line 8 plus line 9.
Line 11 = Yearly Average Annual Sales, calculated from Line 10.
PNW Thermal Displacement Market = Displaceable Thermal Resources minus the Yearly Average of Net Sales. Line 3 minus line 11.

TABLE 5

COMPARISON OF 1993-94 ALTERNATIVE OPERATING PLAN
AND RECENT ASSURED OPERATING PLAN STUDIES

	1989-90	1990-91	1991-92	1992-93	1993-94
MICA TARGET OPERATION (ksfd or cfs)					
- AUG 1	3456.2	3456.2	FULL	3456.2	3456.2
- AUG 2	FULL	FULL	FULL	FULL	FULL
- SEP	FULL	FULL	FULL	FULL	FULL
- OCT	10000	10000	FULL	FULL	10000
- NOV	3122.2	3122.2	3122.2	3246.2	14000
- DEC	26000	23000	23000	22000	22000
- JAN	26000	27000	23000	27000	27000
- FEB	23000	24000	23000	25000	25000
- MAR	17000	20000	18000	23000	24000
- APR 1	15000	15000	18000	27000	22000
- APR 2	10000	10000	18000	10000	15000
- MAY	10000	10000	10000	10000	12000
- JUN	10000	10000	10000	10000	10000
- JUL	3356.2	3356.2	3456.2	3256.2	3256.2
CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)					
NOV 1928 (-41)	533.1	606.5	533.0	690 3	583.7
APR 1929 (-41)	6767.9	7227.1	7049.3	7368.5	7074.8
JUL 1929 (-41)	464.0	759.1	707.1	1036.3	1041.6
AUG 1929 (-41)	8.1	135.9	183.3	560.0	704.9
NOV 1928 (-11)	351.2	538.7	526.7	690.3	303.5
JUL 1929 (-11)	375.6	761.7	708.0	1036.3	1062.3
U.S. STEP I GAINS AND LOSSES (MW)					
- Firm Energy	0	0	-0.2	0.0	-1.8
- Dependable Capacity	-10	+2	0	-6.0	+23.0
- Secondary Energy	-9	-20	+10.5	+16.8	+6.2
BCH STEP I GAINS AND LOSSES (MW)					
- Firm Energy	+72	+26	+12.1	+87.1	+51.8
- Dependable Capacity	-16	-1	-3	+1.0	-18.0
- Secondary Energy	-70	-12	-2.8	-63.2	-30.8
HYDROREG SECONDARY LOAD (MW)					
- AUG 1	11949	8927	10796	11070	10655
- AUG 2	11826	8895	10750	11070	10655
- SEP	11881	8701	10528	9981	10092
- OCT	11977	8936	10726	9981	10237
- NOV	11903	8819	10637	9864	10083
- DEC	12698	8838	10632	9857	10074
- JAN	12731	8853	10677	10996	10914
- FEB	12783	8909	10734	10990	10765
- MAR	12448	8624	10324	10757	10405
- APR 1	10917	8268	9885	10390	10235
- APR 2	10352	7831	9804	10164	10933
- MAY	9874	8394	10135	7156	7114
- JUN	10927	8542	10266	10615	10079
- JUL	12064	8926	10761	11081	10740

TABLE 6

COMPARISON OF 1993-94 ALTERNATIVE DSB STUDY
TO RECENT DDPB STUDIES

	1989-90	1990-91	1991-92	1992-93	1993-94
PNW AREA AVG. ANNUAL LOAD (MW)	20026	18103	18449	18228	18370
- Avg. Annual/Jan. Load (%)	84.26	87.52	87.97	87.67	86.73
- Avg. C.P. Load Factor (%) 1/	75.08	68.54	69.43	68.98	72.37
- Avg. Annual Firm Exports	186	333	376	444	969
- Avg. Annual Firm Surp.(MW)	-632	492	239	388	255
THERMAL RESOURCES (MW) 2/					
- January Peak Capability	11547	9249	9249	9218	9220
- C.P. Energy	7229	5831	5800	5912	6256
- C.P. Minimum Generation	1793	1894	1862	1916	1881
- Avg. Annual System Export Sales	NA	NA	NA	832	1146
- Avg. Ann. Displaceable Market	5436	3937	3938	3095	3158
INSTALLED HYDRO CAPACITY (MW) 3/	34578	34633	34584	29737	29745
- Base System	23808	23808	23808	23808	23806
STEP I/II/III C.P. (MONTHS)	42.5/20/7	42/20/7	42/20/7	42/20/7	42/20/5.5
BASE STREAMFLOWS AT THE DALLES (cfs)					
- Step I Avg. Annual Streamflow	174109	173996	175557	175456	178235
- Step I C.P. Average	112139	112054	112996	112920	112843
- Step II C.P. Average 4/	98777	98717	98193	99637	99548
- Step III C.P. Average 5/	62081	62502	62200	60661	57498
CAPACITY BENEFITS (MW)					
- Step II C.P. Generation	8965.8	8944.9	8903.8	8909.4	8879.5
- Step III C.P. Generation	6951.0	6960.7	6919.6	6871.9	7036.3
- Step II Gain over Step III	2014.8	1984.2	1984.2	2037.5	1843.2
- CANADIAN ENTITLEMENT	1341.8	1447.5	1428.9	1476.9	1273.4
- Change due to Mica Reop.	0.0	0.0	0.0	0.0	-3.1
- Benefit in Sales Agreement	1017.	1022.	932.	844.	755.
ENERGY BENEFITS (Avg. MW)					
- Step II Firm Hydro	8728.7	8773.1	8735.3	8898.2	8839.6
- Step II Thermal Displacement	2057.6	1701.0	1732.1	1327.0	1366.4
- Step II Other Usable	284.8	403.1	396.8	484.0	461.5
- Step II Total Usable	11071.1	10877.2	10864.2	10709.2	10667.5
- Step III Firm Hydro	6254.2	6452.2	6417.0	6659.0	6485.2
- Step III Thermal Displacement	2986.8	2402.3	2408.9	1922.4	1943.1
- Step III Other Usable	697.3	861.6	863.7	940.5	967.4
- Step III Total Usable	9938.3	9716.1	9689.6	9521.9	9395.7
- CANDADIAN ENTITLEMENT	566.4	580.6	587.3	593.7	635.9
- Change due to Mica Reop.	-3.4	-2.7	-3.5	+1.4	+1.4
- Entitlement in Sales Agreement	349.	330.	318.	305.	293.
STEP II PEAK CAPABILITY (MW)	32810	30603	30611	30518	30577
STEP II PEAK LOAD (MW)	25596	24269	24215	24645	24430
STEP III PEAK CAPABILITY (MW)	32756	30613	30574	30612	30429
STEP III PEAK LOAD (MW)	21626	20413	20352	20893	20593

FOOTNOTES FOR TABLE 6

1. The 1989 through 1992 studies included firm contract exports in the computation of the Step I average critical period load factor and the Step II/III study load shape.

2. Thermal resources include combustion turbines, and all existing and planned thermal.

3. Beginning with the 1992-93 Assured Operating Plan, other coordinated hydro and independent hydro were included as adjustments to the Step I load.

4. The 1989 through 1992 Step II/III studies did not update irrigation depletions other than Grand Coulee pumping.

5. The 1993-94 Alternative Operating Plan Step III has a 5 1/2 month critical period.

1993-94
DETERMINATION
OF
DOWNSTREAM
POWER BENEFITS
30-YEAR HYDRO
GENERATION- MW
(ALTERNATE PLAN)