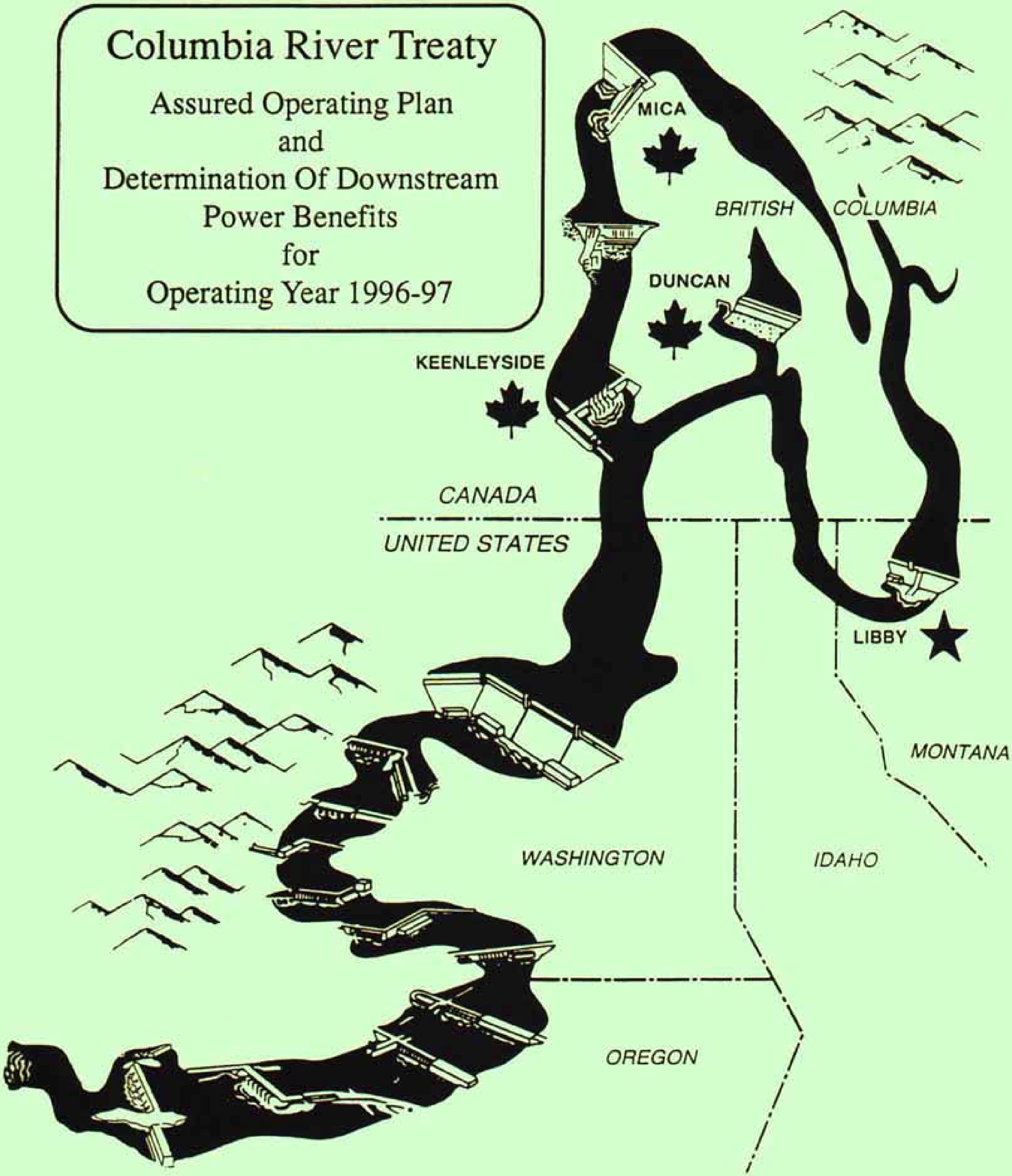
Columbia River Treaty

Assured Operating Plan
and
Determination Of Downstream
Power Benefits
for
Operating Year 1996-97



Columbia River Treaty Operating Committee February 1992

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 1996-97

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February 1992

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.

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 .9 MW decrease in the Canadian Entitlement to annual average usable energy and a 1.0 MW increase 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 1996-97 estimated loads and resources in British Columbia and in the United States Pacific Northwest System. The Entities have agreed that the 1996-97 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 1996-97 conditions, were used.[9]

The Critical Rule Curve for these studies was determined from Bonneville Power Administration Study 97-41. 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 usable storage at Mica in an on-call flood control situation.

3. Development of the Assured Operating Plan

This Assured Operating Plan was developed in accordance with Annex A, paragraph 7 of the Treaty and therefore was designed to produce optimum power generation at-site in Canada and downstream in Canada and the United States. The Mica Operating criteria which were specified in Table 1 were evaluated using the two tests described below.

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

To determine whether optimum generation in both Canada and the United States was achieved in the system regulation studies, the firm energy capability, dependable peaking capability and average annual usable secondary energy were computed for both the Canadian and United States systems.

In the studies for the 1996-97 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 1996-97 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 2 shows the results from studies adopted for the 1996-97 Assured Operating Plan and from studies designed to achieve optimum generation in the United States.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Separate system regulation studies were developed reflecting (i) Canadian storage operation for optimum generation in both Canada and the United States, using the Mica Project operating criteria described in Section 5(c), and (ii) Canadian storage operation for optimum generation in the United States alone. For these Mica Project operating criteria, there is a .9 MW decrease in entitlement to average annual energy, and 1.0 MW increase in entitlement to dependable capacity compared to an operation for optimum generation in the United States alone.

These reductions (and increases) are within the limits specified by the Treaty. The computations of these values are provided in the report Determination of Downstream Power Benefits for the Assured Operating Plan for 1996-97.

4. Operating Rule Curves

The operation of Canadian storage during the 1996-97 Operating Year shall be guided by an Operating Rule Curve for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, and operating rules for specific projects. The Operating Rule Curve is derived from the various curves described below. These operating rules curves are first determined for the individual Canadian projects and then summed to yield the Composite Operating Rule Curve for the whole of Canadian storage. This is in accordance with 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 to produce secondary energy in order to provide a high probability of refilling the storage. In general, the Operating Plan does not permit serving secondary loads at the risk of failing to refill storage and thereby jeopardizing the firm load carrying capability of the United States 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 shown in Tables 5 - 7. These outflows are not the same as the Power Discharge Requirements used in computing the Variable Refill Curve.

(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. The Power Discharge Requirement used in computing the Variable Refill Curves was interpolated linearly between the values shown in Tables 5 - 7. In those years when the January to July runoff volume at the Dalles was less than 80 million acre-feet or greater than 110 million acre-feet, the discharge used was that specified for 80 and 110 million acre-feet respectively.

Variable Refill Curves for Mica, Arrow and Duncan for the 30 years of historical record are recorded in Tables 5 - 7. These illustrate the probable range of these curves based on historical conditions. In actual operation in 1996-97, 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 [10] 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

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, discharges, draft rates, etc. These constraints are included as part of this operating plan.

The following rules, used in the 30-year System Regulation Study[8], will apply to the operation of Canadian storage in the 1996-97 Operating Year.

(a) Operation Above Operating Rule Curve

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

(b) Operation Below Operating Rule Curve

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

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 1. 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 and other project operating criteria at Arrow. The total combined storage draft from Mica and Arrow will not exceed 14.1 million acre-feet unless flood control criteria will not permit the additional Mica storage releases to be retained at Arrow. Should storage releases in excess of 14.1 million acre-feet be made, the target Mica operation will remain as specified in Table 1.

Revelstoke, Canal, Corra Linn, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile and Waneta have been included in the 1996-97 Assured Operating Plan and have been operated as run-of-river projects.

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 1996-97 will reflect the latest available load, resource, and other pertinent data to the extent the Entities agree these data should be included in the plan.

The operating rules to be used in implementation of the Detailed Operating Plan for 1996-97 are generally the same as the operating rules described in this document. The data and criteria contained herein may be reviewed, and updated as agreed by the Entities, to form the basis for a Detailed Operating Plan for 1996-97. Failing agreement on updating the data and/or criteria, the Detailed Operating Plan for 1996-97 will include the rule curves, Mica operating criteria, and other data and criteria provided in this Assured Operating Plan. Actual operation during the 1996-97 Operating Year shall be guided by the Detailed Operating Plan.

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

During the storage drawdown season, Canadian storage should not be drafted below its month-end point at any time during the month unless it can be conservatively demonstrated that sufficient inflow is available, in excess of the minimum outflow required to serve power demand, to refill the reservoir to its end-of-month value as required. During the storage evacuation and refill season, operation will be consistent with the Flood Control Operating Plan. When refill of Canadian storage is being guided by Flood Control Refill Curves,[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 December 1991.

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

3 Columbia River Treaty Entity Agreement on 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 97-41, dated 13 February 1992

9 Report on Modified Flows at Selected Sites, 1928 to 1968 for the 1980 and 2030 Level of Development, Columbia River and Coastal Basins, Columbia River Water Management Group, dated July 1983 and September 1988 respectively.

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

TABLE 1

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
	1 400 -3 300	27 000			
	0 -1 400	29 000			
August 16-31	2 400 - FULL	-	3 529.2	10 000	0.0
	1 300 -2 400	27 000			
	0 -1 300	29 000			
September	2 500 - FULL	-	3 529.2	10 000	0.0
	800 -2 500	27 000			
	0 - 800	32 000			
October	3 260 - FULL	14 000		10 000	0.0
	500 -3 260	27 000			
	0 - 500	32 000			
November	3 290 - FULL	19 000	-	10 000	0.0
	2 900 -3 290	24 000			
	0 -2 900	32 000			
December	3 200 - FULL	23 000	-	15 000	456.2
	2 200 -3 200	29 000			
	0 -2 200	33 000			
January	2 300 - FULL	24 000	-	15 000	356.2
	1 900 -2 300	29 000			
	0 -1 900	33 000			
February	1 350 - FULL	20 000	-	15 000	106.2
	0 -1 350	23 000			
March	1 550 - FULL	19 000	-	15 000	0.0
	950 -1 550	24 000			
	0 - 950	29 000			
April 1-15	0 - FULL		156.2	15 000	0.0
April 16-30	0 - FULL	-	0.0	13 000	0.0
May	0 - FULL	10 000	-	10 000	0.0
June	450 - FULL	10 000	-	10 000	0.0
	0 - 450	22 000			
July	2 300 - FULL	-	3 356.2	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 except in April where a maximum outflow of 33 000 cfs will apply from April 1-15 and a maximum outflow of 27 000 cfs will apply from April 16-30.

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

TABLE 2

COMPARISON OF ASSURED OPERATING PLAN STUDY RESULTS

Study 97-41 provides Optimum Generation in Canada and in the United States.
Study 97-11 provides Optimum Generation in the United States only.

	Study No. 97-41	Study No. 97-11	Net Gain	Weight	Value
1. Firm Energy Capability (Avg. MW)					
U.S. System[1]	12,115.2	12,117.2	-2.0		
Canada[2,3]	2,794.9	2,758.9	+36.0		
Total	14,910.1	14,876.1	+34.0	3	+102.0
2. Dependable Peaking Capacity (MW)					
U.S. System[4]	31,339.0	31,336.0	+3.0		
Canada[2,5]	5,335.0	5,345.0	-10.0		
Total	36,674.0	36,681.0	- 7.0	1	-7.0
3. Average Annual Usable Secondary Energy (Avg. MW)					
U.S. System[6]	3,036.0	3,034.7	+1.2		
Canada[2,7]	224.2	261.1	-36.9		
Total	3,260.2	3,295.8	-35.6	2	-71.2
			Net Change in Value =		+ 23.8

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 includes Mica, Revelstoke, Canal, Corra Linn, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile and Waneta.

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

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

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

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

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

COLUMBIA RIVER TREATY
CRITICAL RULE CURVES
END OF MONTH CONTENTS IN KSFD
1996-97 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	3380.6	3207.7	2921.4	2565.5	1836.3	1096.6	205.8	0.0	0.0	151.5	1799.1	2785.6
2ND YR	3243.8	3301.2	3122.2	2795.5	2100.0	1786.2	778.2	442.7	0.0	1.7	0.0	84.9	1360.5	2541.7
3RD YR	2811.8	2976.3	2901.5	2589.5	1975.6	1409.5	668.3	0.0	0.0	0.0	0.0	0.0	894.2	1626.7
4TH YR	1645.9	1613.3	1149.0	720.2	75.6	0.0	0.0	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	3521.1	3314.3	2901.5	2185.7	1111.6	725.7	672.9	43.3	20.5	1082.4	2626.8	3335.9
2ND YR	3354.9	3350.2	3146.8	2646.2	1925.2	1554.7	650.0	198.6	1.2	0.0	126.7	698.4	1990.5	2999.8
3RD YR	3219.7	3166.2	3108.8	2612.1	2046.2	1397.8	600.0	147.4	0.7	33.3	34.1	532.5	1468.3	1683.6
4TH YR	1716.7	1500.0	1587.3	1278.8	1152.3	466.6	161.0	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	669.6	595.0	510.0	380.0	362.0	200.0	93.0	77.0	85.3	202.8	477.6	664.5
2ND YR	690.0	680.0	665.0	570.0	490.0	370.0	290.0	100.0	81.0	64.0	54.0	168.0	385.0	540.0
3RD YR	545.0	560.0	540.0	420.0	280.0	200.0	160.0	60.0	61.0	11.0	4.0	161.2	384.0	480.0
4TH YR	470.0	500.0	403.0	325.0	180.0	20.0	0.0	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	7571.3	7117.0	6332.9	5131.2	3309.9	2022.3	971.7	120.3	105.8	1436.7	4903.5	6786.0
2ND YR	7288.7	7331.4	6934.0	6011.7	4515.2	3710.9	1718.2	741.3	82.2	65.7	180.7	951.3	3736.0	6081.5
3RD YR	6576.5	6702.5	6550.3	5621.6	4301.8	3007.3	1428.3	207.4	61.7	44.3	38.1	693.7	2746.5	3790.3
4TH YR	3832.6	3613.3	3139.3	2324.0	1407.9	486.6	161.0	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
1996-97 OPERATING YEAR

TABLE 4

MICA

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1206.4	1789.4	2392.4	2570.8	2636.1	2652.7	2647.5	2160.2	1640.0	1380.2	1158.7	1346.9	2492.3	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	10.7	522.4	1126.1	1171.5	1325.6	2007.0	3105.6	3579.6

DUNCAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
40.9	111.8	178.1	208.8	226.3	237.5	247.7	248.5	253.3	262.0	261.7	391.0	571.9	705.8

DUNCAN VARIABLE REFILL CURVE (KSFD)
1996-97 OPERATING YEAR

TABLE 5

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							427.4	418.4	412.4	426.9	414.5	438.7	587.5	705.8
1929-30							425.4	416.5	410.1	424.4	426.0	459.5	599.1	,,
1930-31							370.0	362.2	359.4	379.7	372.6	408.1	587.5	,,
1931-32							1.2	0.0	0.0	0.0	0.0	105.3	440.0	,,
1932-33							,,	,,	,,	,,	,,	0.0	304.1	,,
1933-34							,,	,,	,,	,,	,,	137.5	481.1	,,
1934-35							51.4	52.4	65.1	91.5	98.3	203.9	462.4	,,
1935-36							38.0	38.5	39.6	64.3	69.4	200.1	509.8	,,
1936-37							373.5	365.7	361.5	376.9	364.2	400.2	569.4	,,
1937-38							1.2	0.0	0.0	0.0	19.5	160.9	464.3	,,
1938-39							224.9	220.2	219.3	241.4	241.3	319.5	570.3	,,
1939-40							213.5	208.6	215.1	246.9	248.3	321.6	558.8	,,
1940-41							293.2	287.1	289.7	321.3	331.9	399.3	582.6	,,
1941-42							167.4	165.9	173.7	199.0	208.7	302.1	530.2	,,
1942-43							74.6	76.7	86.5	111.2	138.5	273.4	498.1	,,
1943-44							449.7	439.9	438.7	454.7	444.6	472.0	618.0	,,
1944-45							370.7	363.0	362.6	380.3	367.1	400.6	575.7	,,
1945-46							1.2	0.0	0.0	0.0	0.0	50.0	432.8	,,
1946-47							,,	,,	,,	,,	,,	93.5	445.7	,,
1947-48							,,	,,	,,	,,	,,	111.8	456.8	,,
1948-49							127.0	128.0	134.4	155.7	175.1	286.8	559.5	,,
1949-50							1.2	0.0	0.0	0.0	0.0	119.9	399.9	,,
1950-51							,,	,,	,,	,,	,,	85.5	431.5	,,
1951-52							,,	,,	,,	1.8	24.1	171.1	477.2	,,
1952-53							,,	,,	,,	1.1	21.4	149.5	443.0	,,
1953-54							,,	,,	,,	0.0	0.0	12.2	372.9	,,
1954-55							,,	,,	,,	,,	,,	107.3	381.2	,,
1955-56							,,	,,	,,	,,	,,	60.0	429.4	,,
1956-57							,,	,,	,,	,,	,,	112.6	494.4	,,
1957-58							,,	,,	,,	,,	,,	50.4	445.7	,,
ECC LOWER LIMIT							1.2	0.0	0.0					
POWER DISCHARGE REQUIREMENTS IN CFS FOR						80 MAF--	100	400	400	400	2000	2000	2000	2000
JANUARY - JULY, VOLUME RUNOFF AT THE DALLES						95 MAF--	100	100	100	100	100	100	100	100
FOR VARIABLE REFILL CALCULATION						110 MAF--	100	100	100	100	100	100	100	100
FOR ASSURED REFILL CALCULATION							100	400	400	400	1000	1000	2000	3000

ARROW VARIABLE REFILL CURVE (KSFD)
1996-97 OPERATING YEAR

TABLE 6

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							2847.5	3120.5	3529.4	3579.6	3579.6	3492.9	3579.6	3579.6
1929-30							1557.2	1547.9	2044.8	2184.9	2467.5	2900.1	3504.9	,,
1930-31							1688.7	1942.9	2379.7	2502.3	2642.2	2709.2	3504.1	,,
1931-32							1536.1	712.6	65.8	0.0	0.0	1140.2	2756.2	,,
1932-33							,,	,,	,,	108.4	325.3	1400.0	2760.7	,,
1933-34							,,	,,	,,	0.0	0.0	1921.2	3285.2	,,
1934-35							,,	,,	336.3	617.6	917.2	1733.5	2816.2	,,
1935-36							,,	,,	311.7	424.1	673.9	1754.8	3373.6	,,
1936-37							3138.3	3403.4	3579.6	3579.6	3579.6	3579.6	3579.6	,,
1937-38							1536.1	712.6	448.3	580.5	811.6	1834.3	3019.2	,,
1938-39							1630.4	1760.2	2206.1	2331.1	2553.6	2814.5	3579.6	,,
1939-40							1536.1	1330.3	1806.6	2046.5	2334.3	2599.5	,,	,,
1940-41							2345.2	2631.7	3105.0	3323.7	3579.6	3579.6	,,	,,
1941-42							1536.1	1381.2	1797.0	2039.9	2363.7	2917.8	3557.2	,,
1942-43							1803.5	1906.6	1866.2	1896.1	2046.8	2884.5	3394.1	,,
1943-44							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	,,
1944-45							3106.2	3372.2	,,	,,	,,	,,	,,	,,
1945-46							1536.1	712.6	65.8	0.0	78.3	1522.6	3044.8	,,
1946-47							,,	,,	230.4	356.2	616.7	1727.5	3010.6	,,
1947-48							,,	,,	65.8	99.2	304.4	1628.3	3068.5	,,
1948-49							,,	,,	715.6	1105.8	1582.3	2751.1	3579.6	,,
1949-50							,,	,,	156.3	351.9	588.9	1554.0	2730.9	,,
1950-51							,,	,,	595.1	763.8	992.6	1916.7	3229.3	,,
1951-52							,,	,,	705.5	780.1	936.4	1975.6	3192.3	,,
1952-53							,,	726.9	720.7	797.4	975.5	1999.4	3113.9	,,
1953-54							,,	712.6	65.8	0.0	0.0	1237.2	2724.8	,,
1954-55							,,	,,	,,	,,	336.4	1462.3	2414.6	,,
1955-56							,,	,,	,,	45.2	310.3	1605.7	3054.6	,,
1956-57							,,	,,	,,	229.5	430.7	1427.7	3194.6	,,
1957-58							,,	,,	,,	0.0	205.2	1297.7	2966.5	,,

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ECC LOWER LIMIT		1536.1	712.6	65.8					
POWER DISCHARGE REQUIREMENTS IN CFS FOR JANUARY - JULY, VOLUME RUNOFF AT THE DALLES FOR VARIABLE REFILL CALCULATION	80 MAF--	5000	5000	5000	25000	25000	40000	45000	45000
	95 MAF--	5000	5000	5000	5000	5000	5000	34000	34000
	110 MAF--	5000	5000	5000	5000	5000	5000	30000	30000
FOR ASSURED REFILL CALCULATION		5000	5000	5000	25000	25000	40000	40000	40000

MICA VARIABLE REFILL CURVE (KSFD)
1996-97 OPERATING YEAR

TABLE 7

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							3409.9	3298.5	3264.3	3042.5	2785.7	2505.0	2986.2	3529.2
1929-30							2321.6	2234.1	2189.3	2006.7	1860.2	1887.8	2698.8	"
1930-31							2596.0	2502.6	2453.5	2244.4	2033.5	1908.1	2774.7	"
1931-32							998.0	360.6	190.8	276.0	318.5	896.0	2323.6	"
1932-33							"	"	12.5	81.9	111.8	685.9	2094.2	"
1933-34							"	"	"	0.0	0.0	297.9	2269.6	"
1934-35							1665.6	1577.7	1564.6	1538.2	1407.9	1560.8	2532.9	"
1935-36							1618.4	1532.5	1507.7	1424.5	1291.8	1543.4	2804.1	"
1936-37							3376.8	3266.1	3217.1	2985.5	2776.0	2518.7	3018.8	"
1937-38							998.0	529.9	487.3	571.0	602.7	1123.8	2416.9	"
1938-39							2466.5	2375.9	2340.6	2159.2	1968.5	1932.1	3010.4	"
1939-40							2206.1	2118.3	2100.0	1917.3	1743.9	1723.2	2767.2	"
1940-41							2804.4	2706.3	2676.9	2482.4	2357.9	2291.1	3000.2	"
1941-42							2206.1	2106.7	2069.2	2000.7	1874.9	1991.9	2867.5	"
1942-43							998.0	683.0	642.8	705.1	842.1	1436.5	2460.7	"
1943-44							3473.6	3357.9	3322.7	3092.2	2862.9	2626.9	3159.2	"
1944-45							3429.2	3317.4	3296.1	3082.3	2834.3	2552.8	3077.3	"
1945-46							998.0	360.6	12.5	0.0	0.0	320.8	2156.2	"
1946-47							"	"	64.5	161.2	215.9	849.3	2384.9	"
1947-48							"	"	12.5	0.0	0.0	321.6	2077.0	"
1948-49							2112.1	1995.7	1939.4	1990.8	1981.8	2261.2	3186.1	"
1949-50							998.0	360.6	12.5	0.0	0.0	547.7	1886.5	"
1950-51							"	"	"	"	74.9	670.1	2252.8	"
1951-52							"	"	226.7	284.5	350.2	967.3	2401.3	"
1952-53							1165.3	1063.7	1026.0	1090.3	1088.2	1470.0	2576.8	"
1953-54							998.0	360.6	12.5	0.0	0.0	236.6	1858.2	"
1954-55							1503.2	1409.1	1387.7	1451.0	1404.0	1677.9	2523.9	"
1955-56							998.0	360.6	12.5	0.0	0.0	566.1	2166.6	"
1956-57							"	"	"	3.8	74.5	664.4	2506.9	"
1957-58							"	"	151.0	243.8	293.4	826.6	2428.7	"
[illegible] LOWER LIMIT							998.0	360.6	12.5					
POWER DISCHARGE REQUIREMENTS IN CFS FOR JANUARY - JULY, VOLUME RUNOFF AT THE DALLES FOR VARIABLE REFILL CALCULATION						80 MAF--	3000	3000	3000	22000	22000	25000	27000	27000
						95 MAF--	3000	3000	3000	3000	10000	10000	20000	25000
						110 MAF--	3000	3000	3000	3000	3000	3000	10000	10000
FOR ASSURED REFILL CALCULATION							3000	20000	20000	22000	22000	22000	22000	23000

TABLE 8

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
1996-97 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	418.3	340.8	340.8	348.1	360.5	443.7	574.4	705.8
1929-30	,,	,,	,,	,,	,,	,,	408.4	322.1	322.1	329.8	342.9	430.3	567.7	,,
1930-31	,,	,,	,,	,,	,,	,,	391.0	288.9	288.9	297.2	311.4	406.4	555.7	,,
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	605.3	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	83.5	187.2	488.1	,,
1935-36	,,	,,	,,	,,	,,	,,	277.3	,,	,,	71.3	119.3	351.7	705.8	,,
1936-37	,,	,,	,,	,,	,,	,,	377.7	263.6	263.6	272.5	287.5	388.3	546.6	,,
1937-38	,,	,,	,,	,,	,,	,,	293.0	102.3	102.3	113.2	119.2	245.3	551.9	,,
1938-39	,,	,,	,,	,,	,,	,,	288.0	92.7	92.7	109.3	132.6	399.3	705.8	,,
1939-40	,,	,,	,,	,,	,,	,,	303.2	115.4	115.4	127.2	150.9	410.6	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	345.5	202.1	202.1	212.2	229.3	344.2	524.5	,,
1941-42	,,	,,	,,	,,	,,	,,	328.5	169.9	169.9	179.0	201.5	326.4	501.6	,,
1942-43	,,	,,	,,	,,	,,	,,	333.0	178.4	178.4	192.2	221.1	289.2	653.1	,,
1943-44	,,	,,	,,	,,	,,	,,	416.4	334.7	334.7	342.1	354.7	439.4	572.2	,,
1944-45	,,	,,	,,	,,	,,	,,	384.9	277.3	277.3	278.6	279.4	382.3	580.3	,,
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	,,	,,	,,	,,	,,	,,	371.1	251.0	251.0	256.9	277.0	434.3	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	273.7	65.5	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	,,	,,	,,	,,	,,	,,	273.7	,,	,,	71.9	84.7	234.6	522.7	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	73.2	84.1	237.1	547.6	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	71.9	80.9	154.5	488.8	,,
1955-56	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	84.7	266.6	585.4	,,
1956-57	,,	,,	,,	,,	,,	,,	273.7	,,	,,	74.5	89.9	376.1	655.8	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	96.3	359.4	705.8	,,

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
1996-97 OPERATING YEAR
KSFD

TABLE 9

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3579.6	3579.6	3579.6	3453.6	3453.6	3075.4	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	3579.6
1929-30	,,	,,	,,	,,	,,	,,	2998.3	2928.3	2851.2	2870.1	2902.9	3082.8	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2371.6	1712.7	1008.4	1016.1	1126.6	2224.6	,,	,,
1932-33	,,	,,	,,	,,	,,	,,	2363.5	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	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1373.5	2134.6	3579.6	,,
1936-37	,,	,,	,,	,,	,,	,,	2940.8	2818.8	2684.1	2707.4	2755.8	3266.2	,,	,,
1937-38	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1082.9	1278.3	1831.2	3147.6	,,
1938-39	,,	,,	,,	,,	,,	,,	2584.5	2141.3	1650.3	1719.8	1843.3	2661.3	3579.6	,,
1939-40	,,	,,	,,	,,	,,	,,	2793.4	2529.4	2247.3	2287.2	2380.5	2913.4	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1064.9	1149.8	1934.0	,,	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	1111.2	1322.0	1440.3	2389.1	,,
1943-44	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	,,
1944-45	,,	,,	,,	,,	,,	,,	2582.9	2138.0	1645.5	1672.5	1744.1	2368.8	3347.5	,,
1945-46	,,	,,	,,	,,	,,	,,	2363.5	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	,,	,,	,,	,,	,,	,,	2363.5	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	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1057.2	1172.9	1476.3	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1134.3	1628.0	1898.0	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1090.6	1653.7	3224.8	,,
1955-56	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1008.4	1216.6	1990.6	2993.4	,,
1956-57	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1077.8	1224.3	2651.4	3579.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	1046.9	1190.9	2242.5	,,	,,

TABLE 10

MICA
FLOOD CONTROL STORAGE RESERVATION CURVES
1996-97 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	3385.7	3347.2	3304.6	3304.6	3304.6	3369.1	3447.9	3529.2
1929-30	''	''	''	''	''	''	3352.6	3284.4	3208.7	3208.7	3208.7	3300.7	3413.2	''
1930-31	''	''	''	''	''	''	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	''
1931-32	''	''	''	''	''	''	3105.7	2803.2	2480.5	2480.5	2480.5	2781.5	3149.6	''
1932-33	''	''	''	''	''	''	3101.7	2807.2	''	''	''	''	''	''
1933-34	''	''	''	''	''	''	''	''	''	''	''	''	''	''
1934-35	''	''	''	''	''	''	''	''	''	''	''	''	''	''
1935-36	''	''	''	''	''	''	3105.7	2803.2	''	''	''	''	''	''
1936-37	''	''	''	''	''	''	3330.6	3242.3	3144.5	3144.5	3144.5	3323.3	3398.4	''
1937-38	''	''	''	''	''	''	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	''
1938-39	''	''	''	''	''	''	3193.8	2981.4	2746.8	2746.8	2746.8	2971.4	3246.0	''
1939-40	''	''	''	''	''	''	3274.3	3130.5	2976.4	2976.4	2976.4	3135.1	3329.1	''
1940-41	''	''	''	''	''	''	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	''
1941-42	''	''	''	''	''	''	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	''
1942-43	''	''	''	''	''	''	''	''	''	''	''	''	''	''
1943-44	''	''	''	''	''	''	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	''
1944-45	''	''	''	''	''	''	3193.1	2980.2	2745.0	2745.0	2745.0	2970.0	3245.3	''
1945-46	''	''	''	''	''	''	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	''
1946-47	''	''	''	''	''	''	''	''	''	''	''	''	''	''
1947-48	''	''	''	''	''	''	3105.7	2803.2	''	''	''	''	''	''
1948-49	''	''	''	''	''	''	3101.7	2807.2	''	''	''	''	''	''
1949-50	''	''	''	''	''	''	''	''	''	''	''	''	''	''
1950-51	''	''	''	''	''	''	''	''	''	''	''	''	''	''
1951-52	''	''	''	''	''	''	3105.7	2803.2	''	''	''	''	''	''
1952-53	''	''	''	''	''	''	3101.7	2807.2	''	''	''	''	''	''
1953-54	''	''	''	''	''	''	''	''	''	''	''	''	''	''
1954-55	''	''	''	''	''	''	''	''	''	''	''	''	''	''
1955-56	''	''	''	''	''	''	3105.7	2803.2	''	''	''	2695.5	3172.7	''
1956-57	''	''	''	''	''	''	3101.7	2807.2	''	''	''	2781.5	3149.6	''
1957-58	''	''	''	''	''	''	''	''	''	''	''	''	''	''

COLUMBIA RIVER TREATY
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS IN KSFD
1996-97 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	7571.3	7117.0	6332.9	5218.4	4121.1	3134.4	3019.4	2813.7	2746.0	3744.9	6169.8	7814.6
1929-30	,,	,,	,,	,,	,,	,,	3795.2	,,	,,	,,	,,	,,	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	4069.6	,,	,,	,,	,,	,,	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2110.8	1073.2	256.6	276.0	318.5	2141.5	5519.8	,,
1932-33	,,	,,	,,	,,	,,	,,	,,	,,	78.3	190.3	437.1	2085.9	5159.0	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	0.0	0.0	2356.6	5856.3	,,
1934-35	,,	,,	,,	,,	,,	,,	2828.6	2342.7	1966.0	2089.3	2174.2	3284.3	5770.9	,,
1935-36	,,	,,	,,	,,	,,	,,	2768.0	2283.6	1859.0	1868.6	1902.0	3301.8	6107.7	,,
1936-37	,,	,,	,,	,,	,,	,,	4121.1	3134.4	3019.4	2813.7	2746.0	3744.9	6167.3	,,
1937-38	,,	,,	,,	,,	,,	,,	2110.8	1242.5	935.6	1151.5	1433.8	3119.0	5900.4	,,
1938-39	,,	,,	,,	,,	,,	,,	3803.0	3106.1	2985.4	2793.1	2725.6	3673.4	6168.2	,,
1939-40	,,	,,	,,	,,	,,	,,	3531.2	3052.6	2981.2	2798.6	2732.6	3675.5	6156.7	,,
1940-41	,,	,,	,,	,,	,,	,,	4052.3	3134.4	3019.4	2813.7	2746.0	3744.9	6169.8	,,
1941-42	,,	,,	,,	,,	,,	,,	3485.1	2998.3	2939.8	2750.7	2693.0	3656.0	6128.1	,,
1942-43	,,	,,	,,	,,	,,	,,	2184.2	1485.4	1855.4	1987.8	2306.2	3627.3	6064.4	,,
1943-44	,,	,,	,,	,,	,,	,,	4121.1	3134.4	3019.4	2813.7	2746.0	3744.9	6169.8	,,
1944-45	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1945-46	,,	,,	,,	,,	,,	,,	2110.8	1073.2	78.3	0.0	78.3	1893.4	5633.8	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	294.9	517.4	832.6	2670.3	5841.2	,,
1947-48	,,	,,	,,	,,	,,	,,	,,	,,	78.3	99.2	304.4	2061.7	5602.3	,,
1948-49	,,	,,	,,	,,	,,	,,	3350.7	2836.3	2490.0	2641.7	2659.4	3640.7	6157.4	,,
1949-50	,,	,,	,,	,,	,,	,,	2110.8	1073.2	168.8	351.9	588.9	2221.6	5017.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	607.6	763.8	1067.5	2672.3	5789.9	,,
1951-52	,,	,,	,,	,,	,,	,,	,,	,,	932.2	1066.4	1310.7	3114.0	5984.1	,,
1952-53	,,	,,	,,	,,	,,	,,	2278.1	1789.4	1746.7	1888.8	2085.1	3495.8	6040.9	,,
1953-54	,,	,,	,,	,,	,,	,,	2110.8	1073.2	78.3	0.0	0.0	1486.0	4955.9	,,
1954-55	,,	,,	,,	,,	,,	,,	2616.0	2121.7	1453.5	1380.2	1495.1	2916.5	5288.1	,,
1955-56	,,	,,	,,	,,	,,	,,	2110.8	1073.2	78.3	45.2	310.3	2231.8	5589.4	,,
1956-57	,,	,,	,,	,,	,,	,,	,,	,,	,,	233.3	505.2	2204.7	6092.3	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	216.8	243.8	498.6	2174.7	5840.9	,,

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1996-97

DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 1996-97

February 1992

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 1996-97 Assured Operating Plan (AOP).

The procedures followed in the benefit studies are those provided in Annex A, Paragraph 7, and Annex B of the Treaty; in Articles VIII, IX, and X of the Protocol; in the Entity 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 Studies (1988 Entity Agreements); and in the document, "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated December 1991.

The Canadian Entitlement Benefits were computed from the following studies:

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

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

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

As part of the determination of downstream power benefits for the operating year 1996-97, separate determinations were carried out relating to the limit of year-to-year change in benefits attributable to the operation of Canadian Treaty storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America.

As required by the Canadian Entitlement Purchase Agreement, 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 was separately determined.

2. Results of Canadian Entitlement Computations

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

Dependable Capacity = 1373.4 MW
Average Annual Energy = 547.5 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 1996-97 operating year are based on the formula X - (Y - Z).

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

X is one half of the downstream power benefits derived from the previous year's 96-42 and 96-13 AOP studies.

Y is one half of the downstream power benefits derived from the difference between the previous year's 96-12 and 96-13 AOP studies.

Z is one half of the downstream power benefits derived from the difference between the present year's 97-22 and 97-13 AOP studies.

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

The quantities X and Y were computed in the 1995-96 DDPB. The quantity Z, which is computed from one-half of the downstream power benefits determined for 15 maf of Canadian Treaty storage operated for optimum power generation in the United States of America, is computed in Table 5.

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

Dependable Capacity = 1183.4 - (1182.7 - 1346.0) = 1346.7 MW
Average Annual Energy = 653.2 - (655.2 - 538.8) = 536.8 MW

The computed Canadian Entitlement exceeds these amounts.

4. <u>Effect on Sale of Canadian Entitlement</u>

The Canadian Entitlement to downstream power benefits for operating year 1996-97 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 Sates of America only. The Canadian Entitlement determined from the 1996-97 Assured Operating Plan for this condition would have been:

Dependable Capacity = 1372.4 MW
Average Annual Energy = 548.4 MW

Since the 1996-97 Assured Operating Plan was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America, Section 7 of the Agreement requires that "any reduction in the Canadian Entitlement resulting from action taken pursuant to Paragraph 7 of Annex A of the Treaty shall be determined in accordance with Subsection (3) of Section 6 of this Agreement." A comparison of the Canadian Entitlement for optimum power in Canada and the United States with the Canadian Entitlement to downstream power benefits shown above indicates a <u>decrease</u> in Canadian Entitlement of 0.9 MW of average annual usable energy, and an <u>increase</u> of 1.0 MW in dependable capacity.

Accordingly, the Entities are agreed that the United States Entity is entitled to receive 0.9 MW of energy, but not entitled to receive any dependable capacity during the period 1 April 1996 through 31 March 1997, 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. Determination of Firm Hydro Loads for Step I Studies:

This table shows the loads and resources used in the Step I studies and the computation of the residual hydro load for the Step I study.

Table 2. Determination of Step I Thermal Installations and Thermal Displacement Market:

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 including thermal imports after allowance for reserves, minimum thermal generation, and reductions for the thermal resources used outside the PNW Area. Line 14 in the table shows surplus energy shaped into the first year.

Table 3. Determination of Loads for 1996-97 Step II and III Studies:

This table shows the computation of the Step II and III loads. The monthly loads for Step II and III studies have the same ratio between each month and the annual average as does the Pacific Northwest (PNW) area load. The PNW area firm loads on this table were based on the 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 the 1988 Entity Agreements and in POP.

Table 4. Summary of Power Regulations from 1996-97 Assured Operating Plan:

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

Table 5. Computation of Canadian Entitlement For 1996-97 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.

Chart 1. 1996-97 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

Data from the six most recent Assured Operating Plans and their associated Determination of Downstream Power Benefits is summarized in Tables 6 and 7. Firm energy shifting was not included in the 1991-92 through 1992-93 and the 1996-97 operating plan studies. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Resources

The Pacific Northwest Area firm energy load increased by 1427 annual average MW (aMW). The total exports not including firm surplus energy decreased by 394 aMW, resulting in a 1033 aMW net increase in system firm load. Loads for the 1996-97 AOP were based on the joint BPA/Northwest Power Planning Council May 1991 load forecast.

The total energy capability of the thermal installations increased by 1468 aMW. Major thermal increases included: 1) combustion turbines increased by 477 aMW, mostly due to increased plant factors at existing plants; 2) cogeneration increased by 586 aMW, almost all of it due to new projects; and 3) PURPA resources, a portion of which are now included as thermal resources for the first time, added 249 aMW. These PURPA resources were previously classified as miscellaneous.

Large thermal resources decreased by 1059 aMW primarily because Jim Bridger was transferred from large thermal to thermal imports. Correspondingly, the thermal imports increased by 1294 aMW, primarily due to the import that replaced Jim Bridger. This increase also includes new California contracts, Eastern Montana thermal resources, and existing thermal imports that were not classified as thermal in last year's study.

Analysis of the expected benefits of shifted rule curves compared to non-shifted rule curves indicated that the benefits are less than the cost of the shift payment. Thus, the U. S. Entity elected not to finish or publish results from the shift study.

(b) Operating Procedures

Spill at several plants was reduced or eliminated resulting in a substantial increase in critical period generation. The net Step I critical period generation increase was approximately 100 MW. The Willamette projects, previously regulated hydro projects, are now classified as hydro independent resources.

New rule curve lower limits were implemented at Dworshak, Libby, Albeni, and Grand Coulee. A new Energy Content Curve (ECC) lower limit of 1220 feet at Grand Coulee was implemented in the Step I, II, and III studies. Therefore, in Step II and III studies, Coulee was no longer an annual plant and Variable ECC's were calculated.

Corra Linn was allowed to operate above International Joint Commission rule curves if the Libby and Duncan outflow was not greater than their inflow.

(c) Step III Critical Period

The Step III study had a new critical period of 7 months, October through April 30, 1937. The Step III critical period was very close to being 6 months as approximately 3 ksfd of draft was required to meet load in October.

April and August months were split as in the Step I and II studies. There was no spilt September.

(d) Downstream Power Benefits Computation

The Canadian capacity entitlement increased from 1184.3 MW to 1373.4 MW for a gain of 189.1 MW. The primary reason for the substantial gain in the capacity entitlement is the longer Step III critical period, which resulted in a 217.7 MW decrease in the Step III average critical period generation. The Step II average critical period generation increased by 70.6 MW. Therefore, the difference between the Step II and Step III average critical period generation increased as did the capacity entitlement.

The Canadian energy entitlement decreased from 653.2 aMW to 547.5 aMW, a reduction of 105.7 aMW. Approximately 20 aMW of the decrease in the energy entitlement is due to the comparison of the non-shift study to the 1995-96 Assured Operating Plan which included shift. The energy entitlement was also affected by new power discharge curves, which resulted in an entitlement reduction of 9.4 aMW. However, the primary reason for the decrease in the energy entitlement is an increase of 2642.4 aMW in the thermal displacement market. The major reasons for the increase in the thermal displacement market is an increase of 1468.0 aMW in the energy capability of thermal installations and a reduction of 722.0 aMW in the minimum thermal generation.

TABLE 1

1996-97 ASSURED OPERATING PLAN
DETERMINATION OF FIRM HYDRO LOADS FOR STEP I STUDIES

ENERGY LOAD OF THE PACIFIC NORTHWEST AREA (Avg MW)							ENERGY RESOURCES (Avg MW)								REGULATED HYDRO LOAD (ENERGY) (1929) 9/
PERIOD	PNW AREA LOAD 1/	ANNUAL LOAD SHAPE PERCENT	FIRM EXPORTS 2/	MAINT. 3/	FIRM SURPLUS 4/	TOTAL STEP I STUDY LOAD 5/	HYDRO INDEP. (1929)	IMPORTS 6/	LARGE THERMAL	SMALL THERMAL	COMBST TURBINE	MISC. 7/	TOTAL (1929) 8/		
Aug. 1-15	19000	93.48	825	32	276	20133	1148	1394	5437	23	983	1101	10086		10046.5
Aug. 16-31	18922	93.10	825	27	276	20050	1171	1387	5437	23	876	1101	9995		10054.5
September	18197	89.53	830	9	516	19552	971	1187	5437	23	805	1101	9524		10027.5
October	19043	93.69	395	9	516	19963	967	1210	5300	23	845	1110	9455		10507.5
November	21046	103.55	369	4	516	21935	1009	1771	5348	29	954	1107	10219		11715.5
December	22550	110.95	357	0	516	23423	1052	2055	5437	29	1006	1105	10685		12737.5
January	23329	114.78	348	0	276	23953	924	2098	5437	29	1009	1115	10613		13339.5
February	22246	109.45	353	0	276	22875	685	2025	5437	29	1006	1112	10294		12580.5
March	20975	103.20	361	5	276	21617	895	1502	4977	23	830	1113	9340		12276.5
April 1-15	19844	97.64	366	7	276	20493	1052	1200	3255	23	829	1090	7448		13044.5
April 16-30	19941	98.11	366	8	276	20591	1114	1072	1894	23	888	1050	6041		14549.5
May	19193	94.43	320	20	3276	22809	1532	943	2867	23	972	752	7089		15719.5
June	19263	94.78	778	16	276	20333	1437	1286	4230	23	988	943	8907		11425.5
July	19293	94.92	827	51	276	20447	1131	1409	5245	23	983	1097	9888		10558.5
Annual Average =	20324.6	100.00	511.2	12.7	610.5	21459.0	1073.1	1498.4	4809.9	25.0	931.8	1060.1	9398.5		12060.5
Crit.Per.Avg.(42mo)	20431.0		501.3	11.4	585.7	21529.4		1530.5	4893.9	23.6	932.6	1067.0			
August 1-31	18959.7	93.28	825.00	29.5	275.5	20091.0	1159.5	1390.5	5437.0	23.0	929.5	1101.0	10040.0		10050.5
April 1-30	19892.5	97.87	366.00	7.5	275.5	20541.5	1083.0	1136.0	2574.5	23.0	858.5	1070.0	6744.5		13797.0

PEAK LOAD OF THE PACIFIC NORTHWEST AREA (MW)							PEAK RESOURCES (MW)							REGULATED HYDRO LOAD (PEAK) (1929) 9/
PERIOD	PNW AREA LOAD 1/	LOAD FACTOR PERCENT	FIRM EXPORTS 2/	MAINT. 3/	FIRM SURPLUS 4/	TOTAL STEP I STUDY LOAD 5/	HYDRO INDEP. (1929)	IMPORTS 6/	LARGE THERMAL	SMALL THERMAL	COMTRB	MISC. 7/	TOTAL (1929) 8/	
Aug. 1-15	23728	79.90	2246	4629	345	30948	1918	1731	6252	33	1414	1064	12412	18535.8
Aug. 16-31	23683	79.90	2246	4066	345	30340	1899	1731	6252	33	1236	1064	12215	18124.8
September	23593	77.13	2233	3787	668	30281	1781	1511	6252	33	1176	1064	11817	18464.4
October	26037	73.14	1312	3208	705	31262	1711	1559	6079	33	1260	1064	11706	19555.8
November	28513	73.81	621	2935	698	32767	1738	2629	6079	122	1359	1064	12991	19776.4
December	30538	73.84	588	2037	698	33861	1742	2807	6252	122	1367	1044	13334	20527.1
January	31734	73.51	588	1561	375	34258	1659	2859	6252	122	1468	1064	13424	20833.8
February	30596	72.71	588	2295	379	33858	1320	2812	6252	122	1462	1064	13032	20825.9
March	28128	74.57	588	2646	369	31731	1712	1895	6252	33	1029	1064	11985	19746.5
April 1-15	26768	74.09	588	2751	372	30479	1901	1347	3876	33	1236	1064	9457	21021.9
April 16-30	26850	74.09	588	2483	372	30293	1941	1344	2059	33	1375	1008	7760	22532.9
May	25720	74.62	929	2360	4389	33398	2069	1805	3715	33	1432	558	9612	23786.4
June	24504	78.61	2227	2204	350	29285	2098	1809	5157	33	1423	1017	11537	17748.5
July	24172	79.82	1998	3725	345	30240	1582	1731	6252	33	1414	1047	12059	18181.2
Avg. Crit. Per. Load Factor		75.29												
August 1-31	23728	79.90	2246	4629	345	30948	1918	1731	6252	33	1414	1064	12412	18535.8
April 1-30	26850	74.09	588	2751	372	30479	1941	1347	3876	33	1375	1064	9457	22532.9

NOTE:
1. The PNW Area load does not include the exports, but does include irrigation pumping. The computation of the load shape for Step II/III studies uses these loads
2. Firm exports includes 368 avg. annual MW of firm exports and 143.5 avg. annual MW of seasonal exchange exports that have a matching import.
3. Hydro maintenance is treated as a load instead of a modeled resource reduction.
4. All firm surplus energy is assumed to be exported outside of the PNW Area
5. The total Step I study load is the sum of PNW Area load, firm exports, maintenance, and firm surplus.
6. Imports include 143.5 average annual MW of seasonal exchanges.
7. Miscellaneous resources include purpa, cogeneration, renewable, and energy management system.
8. Total resources other than regulated hydro projects, based on 1929 water conditions for hydro independents.
9. The regulated hydro load is the total Step I study load minus Step I nonregulated hydro resources i.e., the net firm load met by the Step I regulated hydro projects

TABLE 2

1996-97 ASSURED OPERATING PLAN
DETERMINATION OF STEP I THERMAL INSTALLATIONS AND THERMAL DISPLACEMENT MARKET
(Energy in Average MW)

	Aug15	Aug31	Sept	Oct.	Nov.	Dec.	Jan.	Feb.	March	Apr15	Apr30	May	June	July	Annual Average
THERMAL INSTALLATIONS															
1. Large Thermal	5437	5437	5437	5300	5348	5437	5437	5437	4977	3255	1894	2867	4230	5245	4809.9
2. Combustion Turbines	983	876	805	845	954	1006	1009	1006	830	829	888	972	988	983	931.8
3. Co-Generation	623	623	623	632	629	628	638	634	635	612	572	274	509	614	585.5
4. Small Thermal	23	23	23	23	29	29	29	29	23	23	23	23	23	23	25.0
5. Renewable Thermal	46	46	46	46	46	46	46	46	46	46	46	46	2	46	42.4
6. PURPA Thermal (60% of total)	249	249	249	249	249	249	249	249	249	249	249	249	249	252	249.3
7. Minus Plant Sales included above (-)	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-46	-64	-99	-91.6
8. Total Thermal Imports	1374	1367	1172	1189	1735	2008	2038	1956	1441	1170	1042	915	1248	1383	1461.0
9. Minus Seasonal Exch. Imports incl. (-)	0	0	0	-1	-311	-424	-432	-433	-137	0	0	0	0	0	-143.2
10. ...Total Step I Thermal Installations	8636	8522	8256	8184	8580	8880	8915	8825	7965	6085	4615	5300	7185	8447	7870.0
SYSTEM SALES															
11. Total Exports	825	825	830	395	369	357	348	353	361	366	366	320	778	827	511.2
12. Minus Plant Sales Exports (-)	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-46	-64	-99	-91.6
13. Minus Seasonal Exch. Exports (-)	-433	-433	-423	0	0	0	0	0	0	0	0	-8	-422	-431	-143.5
14. Added Surplus Firm Sales	276	276	516	516	516	516	276	276	276	276	276	3276	276	276	610.5
15. ...Total System Sales	569	569	824	812	786	774	525	530	538	543	543	3542	568	573	886.6
16. Uniform Avg. Annual System Sales	887	887	887	887	887	887	887	887	887	887	887	887	887	887	886.6
MINIMUM THERMAL GENERATION															
17. Large Thermal Minimum Generation	679	679	679	614	636	679	679	679	617	401	430	580	658	682	633.1
18. Cogen & Renewable Min. Generation	41	41	41	41	41	34	41	41	41	41	41	41	21	34	38.2
19. PURPA Thermal Min Gen	208	208	208	208	208	208	208	208	208	208	208	208	208	210	207.7
20. ...Total Minimum Generation	928	928	928	863	885	921	928	928	866	650	679	829	887	926	879.0
21. THERMAL DISPL. MARKET	6822	6708	6442	6435	6809	7073	7101	7011	6213	4549	3050	3585	5412	6634	6104.4

NOTES

Lines 7 & 12 Plant sales includes Longview Fibre and 15 percent of Boardman.

Lines 9 & 13 Seasonal exchanges with extraregional utilities. Thermal imports are not included as thermal resources and exports are not included with system sales.

Line 10 Thermal Installations using the total Step I thermal generation, except seasonal exchanges and plant sales, per 1988 Entity Agreement. Sum of lines 1 to 9.

Line 15 System Sales are total exports excluding plant sales and seasonal exchanges. Lines 11 + 12 + 13 + 14.

Line 16 Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.

Lines 17 & 18 Large Thermal minimum generation is Centralia, Jim Bridger, & Valmy. Cogen Thermal is Weyco & Steam Plant, Renewable is Kettle Falls.

Line 19 60% of the total PURPA is thermal. Displaceable PURPA generation is 16.7% of the thermal PURPA.

Line 21 PNW Area Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNW Area firm loads. Line 10 - 16 - 20.

TABLE 3

1996-97 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR
STEP II AND STEP III STUDIES

LOAD OF THE PACIFIC NORTHWEST AREA						STEP II STUDY		STEP III STUDY		
Period	PNW Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Energy Capability of Thermal Installations 2/ aMW	Total Load 3/ aMW	Hydro Load 4/ aMW	Total Load 3/ aMW	Hydro Load 4/ aMW	Period
Aug. 1-15	19000	93.48	23728	79.90	8636	15649.5	7013.5	13381.7	4745.7	Aug. 1-15
Aug. 16-31	18922	93.10	23683	79.90	8522	15585.3	7063.3	13326.8	4804.8	Aug. 16-31
September	18197	89.53	23593	77.13	8256	14988.1	6732.1	12816.2	4560.2	September
October	19043	93.69	26037	73.14	8184	15684.9	7500.9	13412.0	5228.0	October
November	21046	103.55	28513	73.81	8580	17334.7	8754.7	14822.7	6242.7	November
December	22550	110.95	30538	73.84	8880	18573.5	9693.5	15882.0	7002.0	December
January	23329	114.78	31734	73.51	8915	19215.1	10300.1	16430.6	7515.6	January
February	22246	109.45	30596	72.71	8825	18323.1	9498.1	15667.9	6842.9	February
March	20975	103.20	28128	74.57	7965	17276.2	9311.2	14772.7	6807.7	March
April 1-15	19844	97.64	26768	74.09	6085	16344.7	10259.7	13976.1	7891.1	April 1-15
April 16-30	19941	98.11	26850	74.09	4615	16424.6	11809.6	14044.5	9429.5	April 16-30
May	19193	94.43	25720	74.62	5300	15808.5	10508.5	13517.6	8217.6	May
June	19263	94.78	24504	78.61	7185	15866.1	8681.1	13566.9	6381.9	June
July	19293	94.92	24172	79.82	8447	15890.8	7443.8	13588.1	5141.1	July
Annual Average =	20324.6	100.00		75.50	7870.0	16740.5	8870.5	14314.6	6444.6	Annual Avg.
Critical Period Avg =	20431.0			75.29	7974.9	16934.4	8963.5	14995.8	6895.5	Crit.Per.Avg
Step II Crit. Per. Avg	20560.0				7970.9					
Step III Crit. Per. Avg	21291.7				8100.3	Input 5/ =	8963.5	Input 5/ =	6895.5	
August 1-31	18959.7	93.28	23728.0	79.90	8577.2	15616.4	7039.2	13353.4	4776.2	Aug. 1-31
April 1-30	19892.5	97.87	26850.0	74.09	5350.0	16384.6	11034.6	14010.3	8660.3	Apr. 1-30

NOTES:

1. The PNW Area load does not include the exports, but does include pumping. The computation of the load shape for Step II/III studies used these loads.
2. The thermal installations include all thermal used to meet the Step I system load.
3. The total firm load for the Step II/III studies is computed to have the same shape as the load of the PNW Area.
4. The hydro load is equal to the total load minus the Step I study thermal installations.
5. Input is the assumed critical period average generation for the Step II/III hydro studies and is used to calculate the residual hydro loads.

TABLE 4
SUMMARY OF POWER REGULATIONS
FROM 1996-97 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	50 YEAR AVERAGE ANNUAL GENERATION MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	50 YEAR AVERAGE ANNUAL GENERATION MW
HYDRO RESOURCES													
CANADIAN													
Mica			7000			7000							
Arrow			7100			7100							
Duncan			1400			1400							
Subtotal			15500			15500							
BASE SYSTEM													
Hungry Horse	4	430	3072	314	97	3008	212	114	105	3008	328	176	103
Kerr	3	168	1219	155	118	1219	155	108	121	1219	149	130	121
Thompson Falls	6	40	0	40	38	0	40	37	37	0	40	38	36
Noxon Rapids	5	554	231	536	151	0	554	133	202	0	554	155	203
Cabinet Gorge	4	225	0	230	99	0	230	87	116	0	230	99	117
Albeni Falls	3	49	1155	26	26	1155	22	25	25	1155	35	27	27
Box Canyon	4	74	0	71	45	0	70	44	47	0	71	52	2271
Grand Coulee	24+3SS	6684	5185	6382	2016	5072	6382	1771	2308	5072	5883	1190	1273
Chief Joseph	27	2614	0	2586	1106	0	2586	1006	1343	0	2586	711	436
Wells	10	820	0	760	413	0	760	385	477	0	760	282	42
Rocky Reach	11	1267	0	1267	575	0	1267	533	689	0	1267	377	647
Rock Island	18	544	0	544	280	0	544	261	328	0	544	181	300
Wanapum	10	986	0	986	517	0	986	481	598	0	986	331	541
Priest Rapids	10	912	0	912	498	0	912	469	561	0	912	338	503
Brownlee	5	675	975	675	224	974	675	293	290	974	675	282	289
Oxbow	4	220	0	220	92	0	220	119	118	0	220	116	118
Ice Harbor	6	693	0	693	223	0	693	236	306	0	693	186	306
McNary	14	1127	0	1127	655	0	1127	631	795	0	1127	481	742
John Day	16	2484	535	2484	928	0	2484	904	1224	0	2484	686	1193
The Dalles	22+2F	2074	0	2074	737	0	2074	716	972	0	2074	565	955
Bonneville	18+2F	1147	0	1147	592	0	1147	572	721	0	1147	448	687
Kootenay Lake	0	0	673	0	0	673	0	0	0	673	0	0	0
Chelan	2	54	677	52	36	676	51	38	45	676	51	45	42
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	223	0	0	0
Total Base System Hydro		23841	29446	23281	9467	28500	23191	8964	11426	13000	22816	6896	10951
ADDITIONAL STEP I PROJECTS													
Libby	5	604	4980	550	184								
Boundary	6	1055	0	855	367								
Spokane River Plants	24	156	104	162	99								
Hells Canyon	3	450	0	450	180								
Dworshak	3	460	2015	447	174								
Lower Granite	6	932	0	932	215								
Little Goose	6	932	0	932	215								
Lower Monumental	6	932	0	932	219								
Pelton, Rereg., & Round	7	423	274	417	123								
Subtotal		5944	7373	5677	1777								
THERMAL INSTALLATION 1/													
Large Thermal				6252	4894								
Combustion Turbines (All Displ.)				1468	933								
Co-Generation (All Displ.)				667	592								
Small Thermal				122	25								
Renewable Thermal (All Displ.)				49	42								
PURPA Thermal (60% of total)				209	249								
Minus Plant Sales included above (-)				-120	-93								
Total Thermal Imports				2681	1494								
Minus Seas. Exch. Imports incl. (-)				-947	-161								
Total Thermal Installations				10381	7975		10381	7970			10381	8100	
RESERVES 2/				-2539	0		-2100	0			1738	0	
TOTAL RESOURCES				36800	19219		31472	16934			31409	14996	
ESTIMATED LOAD PACIFIC NORTHWEST AREA 3/				31734	20431		26252	16934			22350	14996	
Firm Exports (Less Plant Sales)				588	501								
Minus Seas. Excn. Imports				-947	-161								
Minus Plant Sales				-120	-93								
Surplus Firm Exports (less Plant Sales)				375	584								
Firm Imports (not incl. Thermal Imports)				-178	-38								
Miscellaneous Resources 4/				-139	-182								
Other Coordinated Hydro				-2381	-871								
Independent Hydro Resources				-1591	-963								
Estimated Hydro Maintenance				1561	11								
TOTAL STEP I LOADS				28902	19219								
SURPLUS				7898	0		5220	0			9059	0	
CRITICAL PERIOD Starts				September 1, 1928			September 1, 1943				October 1, 1936		
Ends				February 29, 1932			April 30, 1945				April 30, 1937		
Length (Months)				42 Months			20 Months				7 Months		
Study Identification				97-41			97-42				97-13		

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.
4/ Non thermal misc. incl. 40% PURPA plus Energy Management System.

TABLE 5

COMPUTATION OF CANADIAN ENTITLEMENT FOR 1996-97 ASSURED OPERATING PLAN

A. Optimum Power Generation in Canada and the U.S. (From 97-42)
B. Optimum Power Generation in the U.S. Only (From 97-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 97-22)

Determination of Dependable Capacity Credited to Canadian Storage - MW

	(A)	(B)	(C)
Step II - Critical Period Avg. Generation 1/	8963.5	8962.0	8922.3
Step III - Critical Period Avg. Generation 2/	6895.5	6895.5	6895.5
Gain Due to Canadian Storage	2068.0	2066.5	2026.8
Average Critical Period Load Factor in % 3/	75.3	75.3	75.3
Dependable Capacity Gain 4/	2746.7	2744.7	2692.0
Canadian Share of Dependable Capacity 5/	1373.4	1372.4	1346.0

Determination of Increase in Average Annual Usable Energy - Average MW

Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8871.0	8870.0	8830.0
Thermal Replacement Energy 7/	2037.4	2041.1	2054.6
Other Usable Secondary Energy 8/	207.0	206.0	213.4
System Annual Average Usable Energy	11115.4	11117.1	11098.0
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6445.0	6445.0	6445.0
Thermal Replacement Energy 7/	2951.6	2951.6	2951.6
Other Usable Secondary Energy 8/	623.7	623.7	623.7
System Annual Average Usable Energy	10020.3	10020.3	10020.3
Average Annual Usable Energy Gain 9/	1095.1	1096.8	1077.7
Canadian Share of Avg. Annual Energy Gain 5/	547.5	548.4	538.8

1/ Step II values were obtained from the 97-42, 97-12, and 97-22 studies, respectively
2/ Step III values were obtained from the 97-13 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 served.
7/ Avg. secondary generation limited to Potential Thermal Displacement market
8/ Forty percent (40%) of the remaining secondary energy.
9/ Difference between Step II and Step III Annual Average Usable Energy

TABLE 6

COMPARISON OF RECENT ASSURED OPERATING PLAN STUDIES

	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97
MICA TARGET OPERATION (ksfd or cfs)						
- AUG 1	FULL	3456.2	3456.2	3456.2	3456.2	3456.2
- AUG 2	FULL	FULL	FULL	FULL	FULL	FULL
- SEP	FULL	FULL	FULL	FULL	FULL	FULL
- OCT	FULL	FULL	10000	3428.4	3428.4	14000.0
- NOV	3122.2	3246.2	19000	22000	22000	19000.0
- DEC	23000	22000	22000	24000	24000	23000.0
- JAN	23000	27000	26000	27000	27000	24000.0
- FEB	23000	25000	25000	25000	25000	20000.0
- MAR	18000	23000	22000	25000	25000	19000.0
- APR 1	18000	27000	25000	24000	24000	156.2
- APR 2	18000	10000	18000	14000	14000	0.0
- MAY	10000	10000	10000	10000	10000	10000.0
- JUN	10000	10000	10000	10000	10000	10000.0
- JUL	3456.2	3256.2	3256.2	3356.2	3356.2	3356.2
CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)						
NOV 1928 (-41)	533.0	690.3	761.6	1272.6	1272.7	1481.7
APR 1929 (-41)	7049.3	7368.5	7754.1	7801.6	7801.6	7708.8
JUL 1929 (-41)	707.1	1036.3	1139.5	1140.5	1140.5	1028.6
AUG 1929 (-41)	183.3	560.0	983.4	1060.4	1060.4	483.2
NOV 1928 (-11)	526.7	690.3	501.7	1275.3	1275.3	1483.6
JUL 1929 (-11)	708.0	1036.3	1143.0	1142.8	1142.8	1036.6
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)						
- U.S. Firm Energy	-0.2	0.0	-1.4	-4.4	-4.4	-2.0
- U.S. Dependable Capacity	0.0	-6.0	+3.0	+2.0	+2.0	+3.0
- U.S. Secondary Energy	+10.5	+16.8	-8.1	+2.9	+2.9	+1.3
- BCH Firm Energy	+12.1	+87.1	+40.1	+56.0	+56.0	+36.0
- BCH Dependable Capacity	-3.0	+1.0	-14.0	+16.0	+16.0	-10.0
- BCH Secondary Energy	-2.8	-63.2	-27.0	-38.3	-38.3	-36.9
HYDROREG SECONDARY LOAD (MW)						
- AUG 1	10796	11070	10655	11475	11475	14510
- AUG 2	10750	11070	10655	11475	11475	14396
- SEP	10528	9981	10092	11466	11466	14147
- OCT	10726	9981	10237	12021	12021	14616
- NOV	10637	9864	10083	12272	12272	15412
- DEC	10632	9857	10074	12443	12443	15951
- JAN	10677	10996	10914	12633	12633	16000
- FEB	10734	10990	10765	12641	12641	15884
- MAR	10324	10757	10405	11909	11909	15031
- APR 1	9885	10390	10235	11817	11817	13840
- APR 2	9804	10164	10933	11573	11573	13267
- MAY	10135	7156	7114	8114	8114	10734
- JUN	10266	10615	10079	11236	11236	14260
- JUL	10761	11081	10740	11590	11590	14648

TABLE 7

COMPARISON OF RECENT DDPB STUDIES

	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97
PNW AREA AVG. ANNUAL LOAD (MW)	18449.0	18228.0	18370.0	18898.0	18898.0	20325.0
-Avg. Annual/Jan. Load (%)	88.0	87.7	86.7	86.7	86.7	87.1
-Avg. C.P. Load Factor (%) 1/	69.4	69.0	72.4	75.2	75.2	75.3
-Avg. Annual Firm Exports	376.0	444.0	969.0	905.0	905.0	511.0
-Avg. Annual Firm Surplus (MW) 2/	239.0	388.0	255.0	255.0	255.0	610.5
THERMAL INSTALLATIONS (MW) 3/						
-January Peak Capability	9249	9218	9220	9225	9225	10381
-Critical Period (C.P.) Energy	5800	5912	6256	6491	6491	7975
-C.P. Minimum Generation	1862	1916	1881	1621	1621	675
-Avg. Annual System Export Sales	NA	832	1146	1440	1440	887
-Avg. Ann. Displaceable Market 4/	3938	3095	2689	3462	3462	6104
INSTALLED HYDRO CAPACITY (MW) 5/	34584	29737	29745	29680	29680	29785
-Base System	23808	23808	23806	23736	23736	23841
STEP I/II/III C.P. (MONTHS)	42/20/7	42/20/7	42/20/5.5	42/20/6	42/20/6	42/20/7
BASE STREAMFLOWS AT THE DALLES (cfs)						
-Step I 50-yr. Avg. Streamflow	175557	175456	178235	179502	179502	179338
-Step I C.P. Average	112996	112920	112843	113177	113177	113053
-Step II C.P. Average 6/	98193	99637	99548	100146	100146	100036
-Step III C.P. Average 7/	62200	60661	57498	64733	64733	64756
CAPACITY BENEFITS (MW)						
-Step II C.P. Generation	8903.8	8909.4	8869.5	8892.9	8892.9	8963.5
-Step III C.P. Generation	6919.6	6871.9	7036.3	7113.5	7113.5	6895.5
-Step II Gain over Step III	1984.2	2037.5	1833.2	1779.4	1779.4	2068.0
-CANADIAN ENTITLEMENT	1428.9	1476.9	1266.5	1183.4	1183.4	1373.4
-Change due to Mica Reop	0	0	-2.3	+0.7	+0.7	+1.0
-Benefit in Sales Agreement	932.0	844.0	755.0	666.0	576.0	486.0
ENERGY BENEFITS (aMW)						
-Step II Firm Hydro	8735.3	8898.2	8970.2	8928.3	8928.3	8871.0
-Step II Thermal Displacement	1732.1	1327.0	1148.2	1422.3	1422.3	2037.4
-Step II Other Usable	396.8	484.0	492.8	421.0	421.0	207.0
-Step II Total Usable	10864.2	10709.2	10611.1	10771.6	10771.6	11115.4
-Step III Firm Hydro	6417.0	6659.0	6485.2	6401.4	6401.4	6445.0
-Step III Thermal Displacement	2408.9	1922.4	1783.1	2123.8	2123.8	2951.6
-Step III Other Usable	863.7	940.5	1031.4	940.0	940.0	623.7
-Step III Total Usable	9689.6	9521.9	9299.7	9465.2	9465.2	10020.3
-CANADIAN ENTITLEMENT	587.3	593.7	655.7	653.2	653.2	547.5
-Change due to Mica Reoperation	-3.5	+1.4	+4.6	-2.0	-2.0	-0.9
-ENTITLEMENT in Sales Agreement	318.0	305.0	293.0	279.0	268.0	254.0
STEP II PEAK CAPABILITY (MW)	30611	30518	30579	30530	30530	31472
STEP II PEAK LOAD (MW)	24215	24645	24414	24069	24069	26252
STEP III PEAK CAPABILITY (MW)	30574	30612	30429	30299	30299	31409
STEP III PEAK LOAD (MW)	20352	20893	20593	20273	20273	22350

FOOTNOTES FOR TABLE 7

1. The 1991-92 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. In accordance with the 1988 Entity Agreements, firm exports were excluded from this computation in subsequent studies. The average critical period load factor for the 1996-97 Assured Operating Plan uses the monthly load factor for all months, including April and August.

2. Average annual firm surplus is the additional shaped load including the surplus shaped in May.

3. Thermal installations include combustion turbines, and all existing and planned thermal. Beginning with the 1996-97 Assured Operating Plan, thermal installations also includes cogeneration, renewable thermal, purpa, and thermal imports minus plant sales and seasonal exchange imports.

4. Displacement market for the 1993-94 Assured Operating Plan with shifted firm energy is 2689 MW; with energy returned is 3326 MW. Displacement market for the 1994-95 and 1995-96 Assured Operating Plans with shifted energy is 3462 MW. For the 1930 through 1932 return years the thermal displacement is 4063 MW, 4163 MW and 4025 MW respectively.

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

6. The 1991-92 Step II/III studies did not update irrigation depletions other than Grand Coulee pumping.

7. The 1993-94 Assured Operating Plan Step III has a five and half month critical period, while the 1994-95 and 1995-96 have a six month critical period, and the 1996-97 has a seven month critical period.

CHART 1
1996-97
DETERMINATION
OF
DOWNSTREAM
POWER BENEFITS
30-YEAR HYDRO
GENERATION- MW