COLUMBIA RIVER TREATY

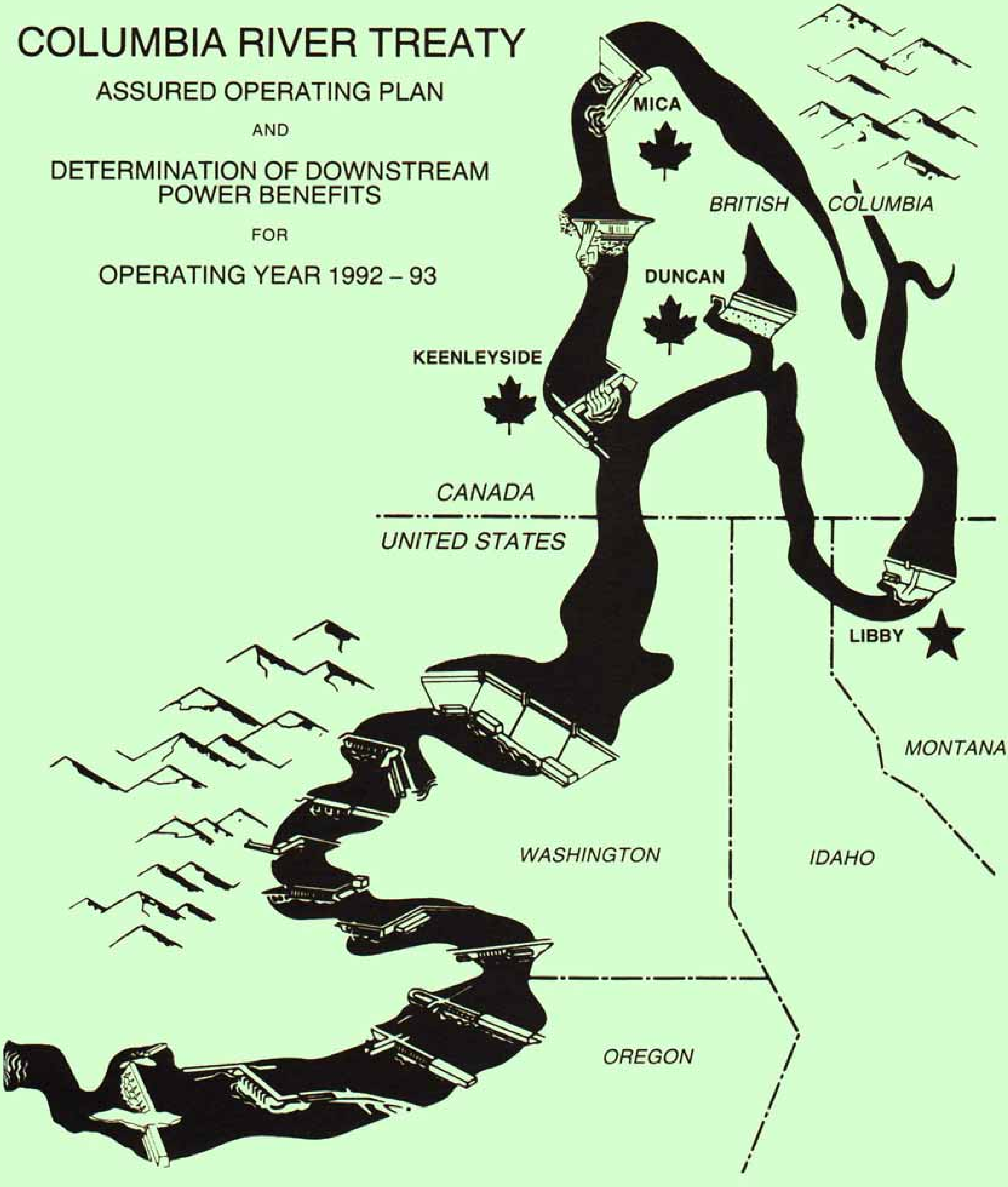
ASSURED OPERATING PLAN

AND

DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR

OPERATING YEAR 1992 – 93



COLUMBIA RIVER TREATY OPERATING COMMITTEE SEPTEMBER 1988

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 1992 – 93

HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN

FOR OPERATING YEAR 1992-93

September 1988

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. The data assumed for this Assured Operating Plan will undergo review by the Entities immediately prior to the 1992-93 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 this Assured Operating Plan will form the basis for the Detailed Operating Plan for 1992-93.

This Assured Operating Plan was prepared in accordance with the principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans./1 It is based on criteria contained in Annex A and Annex B of the Columbia River Treaty,/2 Protocol,/3 Terms of Sale,/4 and the Columbia River Treaty Flood Control Operating Plan./5

The Assured Operating Plan consists of:

i) 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.

ii) 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/6 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.

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 an increase of 1.4 average megawatts of annual usable energy in the Canadian Entitlement to downstream power benefits 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 1992-93 estimated loads and resources in British Columbia and in the United States Pacific Northwest System. The Entities have agreed that the 1992-93 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 1992-93 conditions, were used. The streamflows were derived from the 1980 Level Modified Streamflows/7 with an update in irrigation depletion estimates from the 1970 Level Modified Streamflows/8.

The Critical Rule Curve for these studies was determined from Bonneville Power Administration Study 93-41. 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 1992-93 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 1992-93 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 10 shows the results from the studies adopted for the 1992-93 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 1992-93 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 1.

(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 storages 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 2.

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 3 - 5.

Variable Refill Curves for Mica, Arrow and Duncan for the 30 years of historical record are recorded in Tables 3 - 5. These illustrate the probable range of these curves based on historical conditions. In actual operation in 1992-93, 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 3 - 5.

(d) Upper Rule Curve.

The Upper Rule Curves/9 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 6 - 8; however, the tables do not reflect the constraint that the Upper Rule Curve not be lower than the Variable Refill Curve. Tables 7 and 8 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 9 to illustrate the probable future range of these curves based on historical conditions.

5. Operating Rules

The following rules, used in the 93-41 System Regulation Study, will apply to the operation of Canadian storage in the 1992-93 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 11. 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 11.

Revelstoke has been included in the 1992-93 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 1992-93 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 1992, the Assured Operating Plan contained herein will be reviewed and the data and criteria updated, as agreed by the Entities, to form the basis for a Detailed Operating Plan for the 1992-93 Operating Year. Failing agreement on updating the Assured Operating Plan, the Detailed Operating Plan will include all data and criteria given in this Assured Operating Plan. Actual operation during the 1992-93 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,/5 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 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.

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

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

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

6 BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 93-41, dated 1 August 1988.

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

8 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.

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

TABLE 1

COLUMBIA RIVER TREATY
CRITICAL RULE CURVES
END OF MONTH CONTENTS IN KSFD
1992-93 OPERATING YEAR

MICA

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3529.2	3529.2	3526.2	3372.7	3334.2	3064.1	2300.8	1487.7	943.6	534.6	361.6	766.2	2408.1	2935.2
2ND YR	3370.8	3388.0	3302.8	3099.2	2856.0	2609.7	1765.1	1213.3	771.0	507.5	478.5	427.5	1530.3	2762.8
3RD YR	3068.2	3225.4	3242.1	3059.6	2854.9	2383.7	1622.2	1225.0	474.8	162.2	4.2	140.9	1337.2	2335.0
4TH YR	2511.5	2597.8	2476.0	2080.1	1280.5	583.4	14.1	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	3578.4	3404.7	3364.7	2716.5	2014.6	1122.9	1074.6	372.9	84.5	802.3	2343.7	3278.1
2ND YR	3466.7	3373.2	3355.6	3125.1	2803.7	2332.2	1444.9	698.5	398.2	173.8	233.2	495.8	2036.5	3076.0
3RD YR	3282.8	3213.7	3278.2	3067.0	2791.7	2048.3	1214.9	132.8	334.2	85.6	0.0	448.4	1762.3	2398.5
4TH YR	2577.1	2552.6	2481.0	2222.6	1969.9	793.7	584.5	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	705.5	658.3	425.4	222.2	25.8	8.7	5.1	0.0	0.0	117.5	392.3	565.0
2ND YR	484.6	493.4	487.7	298.7	94.6	0.3	0.6	0.3	5.5	0.0	0.0	94.0	109.7	153.7
3RD YR	183.7	213.7	262.4	154.9	3.5	0.2	0.1	0.8	0.1	0.0	0.0	131.8	110.1	38.9
4TH YR	0.1	0.1	0.7	1.2	1.9	0.8	2.9	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	7435.7	7124.3	6002.8	4341.2	2619.3	2023.3	907.5	446.1	1686.0	5144.1	6778.3
2ND YR	7322.1	7254.6	7146.1	6523.0	5754.3	4942.2	3210.6	1912.1	1174.7	681.3	711.7	1017.3	3676.5	5992.5
3RD YR	6534.7	6652.8	6782.7	6281.5	5650.1	4432.2	2837.2	1358.6	809.1	247.8	4.2	721.1	3209.6	4772.4
4TH YR	5088.7	5150.5	4957.7	4303.9	3252.3	1377.9	601.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 2

COLUMBIA RIVER TREATY
ASSURED REFILL CURVES
END OF MONTH CONTENTS IN KSFD
1992-93 OPERATING YEAR

MICA

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1760.7	2341.2	2947.5	3128.3	3195.4	3213.5	3209.7	3199.4	2602.7	2298.4	2032.5	2125.3	2965.0	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	130.0	305.8	357.1	393.1	1074.6	1209.8	1333.8	2107.1	3262.8	3579.6

DUNCAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
25.6	96.5	162.8	193.5	211.0	222.2	232.4	241.6	255.7	244.9	234.1	341.7	531.6	705.8

DUNCAN VARIABLE REFILL CURVE (KSFD)
1992-93 OPERATING YEAR

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							443.9	416.3	419.0	413.7	439.2	427.9	584.7	705.8
1929-30							441.9	414.3	416.7	411.2	449.6	448.8	596.1	,,
1930-31							386.5	360.1	366.0	367.2	401.0	397.2	584.7	,,
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							113.0	90.6	106.8	124.5	179.2	217.0	473.4	,,
1935-36							88.7	67.2	73.2	88.2	146.4	207.3	517.2	,,
1936-37							390.0	363.6	368.1	364.5	393.4	389.3	566.9	,,
1937-38							1.2	1.6	0.8	16.2	91.5	168.0	471.8	,,
1938-39							241.4	218.0	225.9	231.3	281.5	308.4	567.7	,,
1939-40							229.7	206.5	221.7	236.7	287.9	310.5	556.4	,,
1940-41							309.7	284.9	296.3	309.8	364.0	388.4	579.8	,,
1941-42							229.1	204.4	215.9	230.4	280.0	315.4	540.1	,,
1942-43							121.4	96.5	105.7	131.9	199.9	280.8	505.0	,,
1943-44							465.9	437.8	445.3	441.0	466.6	461.3	614.7	,,
1944-45							387.2	360.8	369.2	367.9	396.1	389.7	573.1	,,
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							,,	,,	,,	,,	60.4	118.7	392.5	,,
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	100	100	1700	1700	1700	1700	1700
FOR JANUARY THROUGH JULY						90 MAF--	100	100	100	900	900	900	900	900
VOLUME RUNOFF AT THE DALLES						95 MAF--	100	100	100	100	100	100	100	100

ARROW VARIABLE REFILL CURVE (KSFD)
1992-93 OPERATING YEAR

TABLE 4

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							3138.8	2852.4	3305.7	3573.4	3579.6	3378.0	3579.6	3579.6
1929-30							1522.6	1276.6	1818.2	2179.4	2946.0	2784.5	3536.3	,,
1930-31							1928.2	1672.0	2153.3	2490.7	3104.7	2593.0	3535.2	,,
1931-32							627.2	246.2	183.3	0.0	0.0	888.1	2797.9	,,
1932-33							,,	,,	,,	,,	315.1	1075.2	2750.6	,,
1933-34							,,	,,	,,	,,	363.1	1508.9	3224.1	,,
1934-35							,,	335.6	494.4	648.6	1197.4	1514.4	2831.5	,,
1935-36							,,	320.9	459.8	599.8	1078.2	1585.9	3263.0	,,
1936-37							3428.7	3135.0	3579.6	3579.6	3579.6	3576.5	3579.6	,,
1937-38							627.2	246.2	183.3	184.6	847.5	1583.8	3064.4	,,
1938-39							1740.0	1488.5	1978.9	2322.0	3023.5	2698.1	3579.6	,,
1939-40							1260.9	1016.5	1579.4	2043.1	2824.5	2483.3	,,	,,
1940-41							2635.6	2361.7	2879.6	3296.6	3579.6	3579.6	,,	,,
1941-42							1613.2	1458.3	1537.8	1717.8	2547.0	2486.3	3403.9	,,
1942-43							1280.2	1119.1	1048.8	1121.7	2073.0	2592.3	3456.7	,,
1943-44							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	,,
1944-45							3396.0	3103.1	,,	,,	,,	,,	,,	,,
1945-46							627.2	246.2	183.3	0.0	283.6	1089.7	2968.1	,,
1946-47							,,	,,	,,	,,	668.0	1470.9	3051.1	,,
1947-48							,,	,,	,,	,,	419.6	1156.3	2965.1	,,
1948-49							,,	,,	265.3	810.5	1780.5	2285.6	3579.6	,,
1949-50							,,	,,	183.3	0.0	402.9	1082.8	2622.9	,,
1950-51							,,	,,	,,	32.2	726.4	1442.9	3129.3	,,
1951-52							,,	,,	,,	27.5	672.8	1503.3	3194.7	,,
1952-53							,,	316.7	280.7	415.6	1220.8	1638.6	3151.3	,,
1953-54							,,	246.2	183.3	0.0	59.8	766.0	2616.0	,,
1954-55							,,	,,	,,	,,	612.3	1167.6	2576.5	,,
1955-56							,,	,,	,,	,,	224.0	1133.2	2953.1	,,
1956-57							,,	,,	,,	,,	226.1	962.2	3286.4	,,
1957-58							,,	,,	,,	,,	252.9	1010.5	2988.7	,,
ECC LOWER LIMIT							627.2	246.2	183.3					
POWER DISCHARGE REQUIREMENTS IN CFS						80 MAF--	5000	5000	5000	22000	30000	40000	48000	60000
FOR JANUARY THROUGH JULY						90 MAF--	5000	5000	5000	9600	9600	20000	35000	45000
VOLUME RUNOFF AT THE DALLES						95 MAF--	5000	5000	5000	5000	5000	10000	25000	47000

MICA VARIABLE REFILL CURVE (KSFD)
1992-93 OPERATING YEAR

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							3529.2	3529.2	3529.2	3529.2	3529.2	3064.5	3398.5	3529.2
1929-30							,,	3483.6	2832.2	2675.5	2728.5	2445.9	3117.3	,,
1930-31							,,	3529.2	3096.7	2910.3	2889.0	2466.2	3191.6	,,
1931-32							1395.2	1278.5	1233.4	1391.9	1558.6	1527.5	2794.3	,,
1932-33							1330.4	1218.0	1190.2	1348.2	1492.6	1422.6	2632.6	,,
1933-34							514.3	419.0	384.9	583.3	850.6	1165.9	2882.6	,,
1934-35							2050.1	1932.3	1818.2	1932.9	2180.3	1888.1	2781.8	,,
1935-36							2252.5	2136.5	1874.3	1902.3	2112.4	1934.8	3094.3	,,
1936-37							3529.2	3529.2	3529.2	3529.2	3529.2	3078.5	3430.5	,,
1937-38							1693.4	1573.3	1528.6	1681.8	1820.6	1754.8	2884.9	,,
1938-39							3529.2	3529.2	2983.7	2826.1	2828.8	2490.2	3422.1	,,
1939-40							3485.8	3367.9	2743.1	2587.4	2620.9	2281.0	3184.4	,,
1940-41							3529.2	3529.2	3320.7	3145.9	3189.8	2850.3	3412.3	,,
1941-42							2644.9	2516.2	2353.8	2412.3	2626.0	2333.9	3117.7	,,
1942-43							2322.3	2189.1	2146.8	2270.7	2429.0	2394.2	3121.0	,,
1943-44							3529.2	3529.2	3529.2	3529.2	3529.2	3186.7	3529.2	,,
1944-45							,,	,,	,,	,,	,,	3112.7	3487.6	,,
1945-46							1068.7	961.8	914.8	1071.7	1245.3	1217.9	2788.9	,,
1946-47							1246.1	1135.5	1117.5	1288.8	1472.4	1488.2	2858.7	,,
1947-48							1171.2	1059.2	1026.1	1175.0	1332.1	1276.3	2745.7	,,
1948-49							2882.1	2737.1	2678.7	2785.0	2844.3	2681.0	3510.4	,,
1949-50							1493.6	1377.8	1321.0	1465.0	1609.0	1503.0	2559.3	,,
1950-51							1535.3	1418.5	1394.0	1552.7	1718.0	1625.7	2917.6	,,
1951-52							1907.0	1779.6	1730.0	1855.0	1973.2	1923.6	3062.8	,,
1952-53							2210.6	2079.7	2039.9	2167.3	2247.0	2082.1	3029.6	,,
1953-54							1072.7	965.7	949.5	1118.3	1282.0	1191.2	2531.6	,,
1954-55							1908.3	1784.6	1761.0	1911.0	2078.8	1896.8	2731.9	,,
1955-56							1392.5	1275.8	1231.0	1380.3	1532.9	1521.7	2833.4	,,
1956-57							1555.0	1437.8	1407.8	1563.2	1705.5	1609.8	3160.1	,,
1957-58							1400.3	1286.4	1262.6	1428.2	1593.2	1506.6	2926.0	,,
ECC LOWER LIMIT							317.6	0.0	0.0					
POWER DISCHARGE REQUIREMENTS IN CFS						80 MAF--	3000	3000	22500	25000	25000	25000	32000	38000
FOR JANUARY THROUGH JULY						90 MAF--	3000	3000	3000	3000	3000	20000	25000	30000
VOLUME RUNOFF AT THE DALLES						95 MAF--	3000	3000	3000	3000	15000	15000	20000	29000

TABLE 6

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
1992-93 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	397.3	303.0	303.0	311.0	324.7	416.4	560.6	705.8
1929-30	,,	,,	,,	,,	,,	,,	385.7	281.3	281.3	289.9	304.0	400.8	553.0	,,
1930-31	,,	,,	,,	,,	,,	,,	368.5	248.0	248.0	257.1	272.7	377.1	540.9	,,
1931-32	,,	,,	,,	,,	,,	,,	272.2	65.5	65.5	80.6	108.9	281.3	609.5	,,
1932-33	,,	,,	,,	,,	,,	,,	,,	,,	,,	75.1	94.2	191.6	573.2	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	65.5	127.0	339.8	605.5	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	83.7	187.0	488.0	,,
1935-36	,,	,,	,,	,,	,,	,,	,,	,,	,,	71.1	119.5	351.9	705.8	,,
1936-37	,,	,,	,,	,,	,,	,,	353.9	219.8	219.8	229.4	246.0	356.9	530.9	,,
1937-38	,,	,,	,,	,,	,,	,,	272.2	65.5	65.5	77.1	83.7	217.3	542.4	,,
1938-39	,,	,,	,,	,,	,,	,,	,,	,,	,,	82.7	107.4	385.7	705.8	,,
1939-40	,,	,,	,,	,,	,,	,,	,,	,,	,,	78.1	103.8	,,	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	321.1	156.3	156.3	167.4	186.0	311.0	508.2	,,
1941-42	,,	,,	,,	,,	,,	,,	302.0	121.0	121.0	131.1	155.3	291.9	483.0	,,
1942-43	,,	,,	,,	,,	,,	,,	305.0	126.0	126.0	141.1	172.9	248.0	647.8	,,
1943-44	,,	,,	,,	,,	,,	,,	392.7	294.4	294.4	302.5	316.6	410.4	557.6	,,
1944-45	,,	,,	,,	,,	,,	,,	361.5	234.4	234.4	235.9	236.9	349.9	567.7	,,
1945-46	,,	,,	,,	,,	,,	,,	272.2	65.5	65.5	75.6	95.8	322.1	647.3	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	101.8	314.1	629.7	,,
1947-48	,,	,,	,,	,,	,,	,,	,,	,,	,,	65.5	65.5	300.5	705.8	,,
1948-49	,,	,,	,,	,,	,,	,,	348.3	208.7	208.7	215.2	236.9	408.8	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	272.2	65.5	65.5	72.1	84.7	184.0	525.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	79.6	103.3	285.3	534.4	,,
1951-52	,,	,,	,,	,,	,,	,,	,,	,,	,,	65.5	67.5	92.2	255.1	,,
1952-53	,,	,,	,,	,,	,,	,,	,,	,,	,,	72.1	84.7	234.4	522.8	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	73.1	84.2	236.9	547.5	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	72.1	80.6	154.7	488.5	,,
1955-56	,,	,,	,,	,,	,,	,,	,,	26.7	26.7	26.7	26.7	240.0	578.2	,,
1956-57	,,	,,	,,	,,	,,	,,	,,	65.5	65.5	74.6	89.7	376.1	655.9	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	96.3	359.4	705.8	,,

TABLE 7

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
1992-93 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	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	3579.6
1929-30	,,	,,	,,	,,	,,	,,	3060.8	3047.7	3033.1	3047.2	3071.9	3207.0	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2364.6	1719.2	1008.4	1015.9	1126.8	2224.4	,,	,,
1932-33	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1036.6	1761.6	3034.6	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1784.8	2327.2	3579.6	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1725.8	3034.6	,,
1935-36	,,	,,	,,	,,	,,	,,	,,	,,	,,	1069.9	1373.4	2134.7	3579.6	,,
1936-37	,,	,,	,,	,,	,,	,,	2998.3	2927.7	2850.6	2869.7	2902.5	3082.5	,,	,,
1937-38	,,	,,	,,	,,	,,	,,	2364.6	1719.2	1008.4	1083.0	1278.1	1831.2	3147.5	,,
1938-39	,,	,,	,,	,,	,,	,,	2637.8	2243.6	1805.9	1869.5	1983.4	2735.1	3579.6	,,
1939-40	,,	,,	,,	,,	,,	,,	2849.6	2645.4	2420.0	2454.8	2536.0	2999.8	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	2364.6	1719.2	1008.4	1064.8	1149.5	1934.0	,,	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	1111.2	1321.9	1440.4	2389.3	,,
1943-44	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	,,
1944-45	,,	,,	,,	,,	,,	,,	2641.9	2251.6	1818.0	1842.7	1908.3	2477.0	3368.4	,,
1945-46	,,	,,	,,	,,	,,	,,	2364.6	1719.2	1008.4	1072.4	1242.3	2201.2	3579.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.4	1360.8	2147.3	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	,,	,,	,,	1036.6	1183.3	2216.8	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	,,	,,	,,	1144.5	1375.9	2494.6	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	1103.6	1113.7	1113.7	2232.5	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	1052.2	1101.1	1355.2	3338.1	,,
1951-52	,,	,,	,,	,,	,,	,,	,,	,,	,,	1069.9	1345.1	1792.3	3013.9	,,
1952-53	,,	,,	,,	,,	,,	,,	,,	,,	,,	1057.3	1172.7	1476.2	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1134.4	1628.0	1898.2	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.4	1090.5	1653.7	3224.7	,,
1955-56	,,	,,	,,	,,	,,	,,	,,	857.1	0.0	0.0	289.9	1367.3	2763.4	,,
1956-57	,,	,,	,,	,,	,,	,,	,,	1719.2	1008.4	1077.9	1224.1	2651.4	3579.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	1046.7	1190.9	2242.6	,,	,,

TABLE 8

MICA
FLOOD CONTROL STORAGE RESERVATION CURVES
1992-93 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	3406.7	3387.0	3365.3	3369.9	3380.5	3412.2	3469.7	3529.2
1929-30	,,	,,	,,	,,	,,	,,	3378.5	3332.6	3282.7	3290.2	3305.9	3353.2	3440.0	,,
1930-31	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3431.4	3437.9	3457.1	3492.9	,,
1931-32	,,	,,	,,	,,	,,	,,	3100.7	2808.2	2480.5	2511.8	2577.8	2781.5	3149.6	,,
1932-33	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1935-36	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1936-37	,,	,,	,,	,,	,,	,,	3353.2	3283.7	3208.5	3218.1	3238.3	3300.8	3413.2	,,
1937-38	,,	,,	,,	,,	,,	,,	3100.7	2808.2	2480.5	2511.8	2577.8	2781.5	3149.6	,,
1938-39	,,	,,	,,	,,	,,	,,	3213.1	3018.5	2806.7	2828.4	2873.8	3013.9	3267.5	,,
1939-40	,,	,,	,,	,,	,,	,,	3296.8	3174.3	3042.7	3057.3	3088.1	3182.3	3353.2	,,
1940-41	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3431.4	3437.9	3457.1	3492.9	,,
1941-42	,,	,,	,,	,,	,,	,,	3100.7	2808.2	2480.5	2511.8	2577.8	2781.5	3149.6	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1943-44	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3431.4	3437.9	3457.1	3492.9	,,
1944-45	,,	,,	,,	,,	,,	,,	3214.6	3021.5	2811.3	2832.9	2878.3	3017.5	3269.6	,,
1945-46	,,	,,	,,	,,	,,	,,	3100.7	2808.2	2480.5	2511.8	2577.8	2781.5	3149.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1951-52	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1952-53	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1955-56	,,	,,	,,	,,	,,	3025.0	2067.1	1058.8	100.9	100.9	100.9	803.7	2363.6	,,
1956-57	,,	,,	,,	,,	,,	3428.4	3100.7	2808.2	2480.5	2511.8	2577.8	2781.5	3149.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,

TABLE 9

COLUMBIA RIVER TREATY
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS IN KSFD
1992-93 OPERATING YEAR

FLOW YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7810.1	7435.7	7124.3	6152.2	5456.7	4563.9	3933.0	3753.1	3600.4	4574.1	6759.4	7814.6
1929-30	,,	,,	,,	,,	,,	,,	4964.7	,,	,,	,,	,,	,,	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	5370.3	,,	,,	,,	,,	,,	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2023.6	1526.3	1417.5	1391.9	1594.2	2527.9	6040.1	,,
1932-33	,,	,,	,,	,,	,,	,,	1958.8	1465.8	1374.3	1348.2	1807.7	2497.8	5697.5	,,
1933-34	,,	,,	,,	,,	,,	,,	1142.7	666.8	569.0	583.3	1259.6	2819.3	6595.0	,,
1934-35	,,	,,	,,	,,	,,	,,	2790.3	2358.5	2419.4	2706.0	3409.1	3619.5	6086.7	,,
1935-36	,,	,,	,,	,,	,,	,,	2968.4	2524.6	2407.3	2590.3	3257.1	3728.0	6745.0	,,
1936-37	,,	,,	,,	,,	,,	,,	5456.7	4563.9	3933.0	3753.1	3600.4	4574.1	6759.4	,,
1937-38	,,	,,	,,	,,	,,	,,	2321.8	1821.1	1712.7	1882.6	2759.6	3506.6	6421.1	,,
1938-39	,,	,,	,,	,,	,,	,,	5182.1	4540.3	3903.2	3739.5	3600.4	4540.8	6759.4	,,
1939-40	,,	,,	,,	,,	,,	,,	4700.3	4422.4	3899.0	3744.9	,,	4542.9	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	5456.7	4563.9	3933.0	3753.1	,,	4574.1	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	4487.2	3843.5	3644.3	3738.6	,,	4547.8	,,	,,
1942-43	,,	,,	,,	,,	,,	,,	3723.9	3404.7	3301.3	3524.3	3566.2	4513.2	6732.8	,,
1943-44	,,	,,	,,	,,	,,	,,	5456.7	4563.9	3933.0	3753.1	3600.4	4574.1	6759.4	,,
1944-45	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1945-46	,,	,,	,,	,,	,,	,,	1697.1	1209.6	1098.9	1071.7	1528.9	2364.4	6197.9	,,
1946-47	,,	,,	,,	,,	,,	,,	1874.5	1383.3	1301.6	1288.8	2149.7	3059.5	6363.4	,,
1947-48	,,	,,	,,	,,	,,	,,	1799.6	1307.0	1210.2	1175.0	1795.5	2551.3	6175.3	,,
1948-49	,,	,,	,,	,,	,,	,,	3683.1	3131.1	3021.6	3284.6	3599.5	4526.6	6759.4	,,
1949-50	,,	,,	,,	,,	,,	,,	2122.0	1625.6	1505.1	1465.0	2073.3	2712.7	5590.8	,,
1950-51	,,	,,	,,	,,	,,	,,	2163.7	1666.3	1578.1	1584.9	2455.5	3161.0	6486.5	,,
1951-52	,,	,,	,,	,,	,,	,,	2539.7	2027.4	1914.1	1906.9	2741.7	3605.2	6644.2	,,
1952-53	,,	,,	,,	,,	,,	,,	2842.7	2398.0	2321.4	2606.6	3346.5	3877.2	6567.2	,,
1953-54	,,	,,	,,	,,	,,	,,	1701.1	1213.5	1133.6	1118.3	1341.8	1976.1	5529.5	,,
1954-55	,,	,,	,,	,,	,,	,,	2536.7	2032.4	1945.1	1911.0	2705.2	3183.1	5700.9	,,
1955-56	,,	,,	,,	,,	,,	5963.7	2020.9	1306.6	101.7	100.9	324.9	2003.7	5564.5	,,
1956-57	,,	,,	,,	,,	,,	6152.2	2183.4	1685.6	1591.9	1563.2	1979.8	2691.6	6729.2	,,
1957-58	,,	,,	,,	,,	,,	,,	2028.7	1534.2	1446.7	1428.2	1846.1	2574.3	6368.3	,,

TABLE 10

COMPARISON OF ASSURED OPERATING PLAN STUDY RESULTS

	Optimum Generation in Canada and the United States Study No. 93-41	Optimum Generation in the United States Study No. 93-11	Net Gain	Weight	Value
1. Firm Energy Capability (Avg. MW)					
U.S. System 1/	12,154.0	12,154.0	+0.0		
Canada 2/	1,664.5	1,577.4	+87.1		
Total (Avg. MW)	13,818.5	13,731.4	+87.1	3	+261.3
2. Dependable Peaking Capacity (MW)					
U.S. System 3/	31,448	31,454	-6.0		
Canada 4/	3,536	3,535	+1.0		
Total (MW)	34,984	34,989	-5.0	1	-5.0
3. Average Annual Usable Secondary Energy (Avg. MW)					
U.S. System 5/	3,012.6	2,995.8	+16.8		
Canada 6/	106.6	169.8	-63.2		
Total (Avg. MW)	3,119.2	3,165.6	-46.4	2	-92.8

Net Change in Value = 163.5

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 11

MICA PROJECT OPERATING CRITERIA

Month	End of Previous Period Arrow Storage Content (ksfd)	Period Average Outflow (cfs)	Target Operation End-of-Period[1] Storage Content (ksfd)	Minimum Outflow (cfs)	Minimum[2] Treaty Content (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	2 850 - FULL	-	3 529.2	10 000	0.0
	0 - 2 850	27 000			
November	3 300 - FULL	-	3 246.2	11 000	0.0
	3 000 - 3 300	23 000			
	0 - 3 000	27 000			
December	3 400 - FULL	22 000	-	21 000	0.0
	2 200 - 3 400	27 000			
	0 - 2 200	34 000			
January	1 700 - FULL	27 000	-	27 000	0.0
	0 - 1 700	34 000			
February	0 - FULL	25 000	-	25 000	0.0
March	500 - FULL	23 000	-	23 000	0.0
	0 - 500	27 000			
April 1-15	0 - FULL	27 000	-	22 000	106.2
April 16-30	0 - FULL	10 000	-	10 000	0.0
May	0 - FULL	10 000	-	10 000	0.0
June	0 - FULL	10 000	-	10 000	0.0
July	2 300 - FULL	-	3 256.2	10 000	0.0
	0 - 2 300	27 000			

Note: (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 indicated target minimum storage content. This will override any target flow.

DETERMINATION OF DOWNSTREAM POWER BENEFITS
RESULTING FROM CANADIAN STORAGE
FOR OPERATING YEAR 1992 – 93

DETERMINATION OF DOWNSTREAM POWER BENEFITS

RESULTING FROM CANADIAN TREATY STORAGE

FOR OPERATING YEAR 1992-93

September 1988

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 1992-93 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 Studies (DDPB).

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 1992-93, 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 = 1,476.9 MW
Average Annual Energy = 593.7 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 1992-93 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 AOP studies 92-42 and 92-13 and the quantity Y is derived from the difference between last year's AOP studies 92-12 and 92-13. These computations are set out in the 1991-92 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 = 1,453.2 MW
Average Annual Energy = 589.9 MW

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

Dependable Capacity = 1,428.9 - (1,428.9 - 1,453.2) = 1,453.2 MW
Average Annual Energy = 587.3 - (590.8 - 589.9) = 586.4 MW

The computed Canadian Entitlement exceeds these amounts.

The test required in accordance with Part III, Paragraph 15c(1) of POP was made, but Paragraph 15c(2) controlled the minimum permitted downstream power benefits.

4. Effect on Sale of Canadian Entitlement

The Canadian Entitlement to downstream power benefits for operating year 1992-93 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 1992-93 Assured Operating Plan for this condition would have been:

Dependable Capacity = 1,476.9 MW
Average Annual Energy = 592.3 MW

Since the 1992-93 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 1.4 average megawatts of average annual usable energy, and no change in dependable capacity.

Accordingly, the Entities are agreed that the United States Entity is not entitled to receive during the period 1 April 1992 through 31 March 1993, from B.C. Hydro & Power Authority, any power 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 from 1992-93 Assured Operating Plan For:

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 1992-93 Assured Operating Plan for the Computation of Canadian Entitlement to Downstream 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 1992-93 AOP Step I, II and III Studies

This table shows the computation of the Step I, II and III loads. The load shape for Step II and III studies should have the same ratio between each month and the annual average as does the Pacific Northwest (PNW) area load. In this study, as in previous studies, the load shape for the Step II and III studies included export load assumptions. Future studies will use only the load of the PNW area. 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 1992-93 AOP Studies

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 1992-93 AOP Study to Recent AOP Studies

Table 6. Comparison of 1992-93 DDPB to Recent DDPB Studies

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

Chart 1. Secondary Energy Duration Curve, Steps II and III

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 Agreement on "Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies," there were several changes in the 1992-93 AOP/DDPB studies when compared to previous studies.

The agreement requires the use of updated irrigation depletions in the DDPB studies, limits and defines the effects of flows of power between the Pacific Northwest Area (PNWA) and adjacent areas in the DDPB studies, defines loads and resources, allows firm load shaping in the AOP, and requires the consistent use of operating procedures between the AOP and the DDPB.

The total impact of the agreement, compared to traditional methods, on the 1992-93 AOP/DDPB is a 21 average MW (aMW) increase in the Canadian Entitlement to downstream power benefits.

There were also other changes in input data. An explanation of the more important changes compared to last year's study is given below.

(a) Streamflows

Increased irrigation pumping resulted in a decrease in the Step I average annual streamflow at The Dalles by 101 cubic feet per second (cfs). For the first time, the Step II and III studies used the same streamflow database as the Step I study, except for adjustments for differences in upstream reservoirs. These changes resulted in a 1444 cfs increase in the Step II average critical period streamflow at The Dalles and a 1539 cfs decrease in the Step III average critical period streamflow. These changes are due to the timing of the irrigation depletions and the return flows, and the different lengths of the critical periods. The Grand Coulee pumping return flows were not updated this year due to time constraints, but the effect is known to be insignificant.

(b) Loads and Resources

The average annual Pacific Northwest Area load estimate decreased by 221 MW. The surplus firm energy capability was shaped into the fall months and May as shown on Table 3. The effect of exports was again included in the computation of the load shape for the Step II/III studies because of lack of time to implement the change required by the Principles and Procedures agreements.

The critical period thermal capability increased slightly due to changes in operation and maintenance schedules. The monthly shape of thermal resources was included in the computation of loads for the Step II and Step III studies.

Step I hydro independent installed capacity increased 71 MW.

(c) Operating Procedures

The Step II/III studies were changed to incorporate several operating criteria previously contained only in the Step I study. These include:

i) the refill criteria which is used to compute operating rule curves,
ii) the secondary market limit which is used to limit the production of nonfirm energy by storing any energy that would exceed the market limit, and
iii) the operation of the top two feet of storage at Kootenay Lake.

An increase in forced spill for fish bypass at the mid-Columbia and lower Snake and Columbia River dams caused a decrease in the Step I critical period capability from last year.

The operating rule curves and critical rule curves were lowered due to the shaping of the surplus firm energy. The composite Canadian storage July draft for the first-year critical rule curve increased by about 329.2 thousand second-foot days (ksfd).

Mica Target outflows increased during the winter and the July Mica Target Content was decreased by 200.0 ksfd.

(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.

The Canadian Entitlement to Capacity and Energy Benefits increased by about 48 MW and 6 aMW respectively compared to the 1992 AOP because of the changes required and permitted by the Principles and Procedures agreements.

TABLE 1

COMPUTATION OF CANADIAN ENTITLEMENT FROM 1992-93 ASSURED OPERATING PLAN FOR:

A. Optimum Power Generation in Canada and the U.S. (From AOP 93-42)
B. Optimum Power Generation in the U.S. Only (From AOP 93-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From AOP 93-22)

Determination of Dependable Capacity Credited to Canadian Storage - MW

	(A)	(B)	(C)
Step II - Critical Period Avg. Generation 1/	8,909.4	8,909.4	8,876.8
Step III - Critical Period Avg. Generation 2/	6,871.9	6,871.9	6,871.9
Gain Due to Canadian Storage	2,037.5	2,037.5	2,004.9
Average Critical Period Load Factor in % 3/	68.98	68.98	68.98
Dependable Capacity Gain 4/	2,953.8	2,953.8	2,906.5
Canadian Share of Dependable Capacity 5/	1,476.9	1,476.9	1,453.2

Determination of Increase in Average Annual Usable Energy - Average MW

	(A)	(B)	(C)
Step II (with Canadian Storage) 1/			
Annual Firm Hydro Energy 6/	8,898.2	8,898.2	8,865.9
Thermal Replacement Energy 7/	1,327.0	1,321.2	1,345.6
Other Usable Secondary Energy 8/	484.0	487.0	490.2
System Annual Average Usable Energy	10,709.2	10,706.4	10,701.7
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6,659.0	6,659.0	6,659.0
Thermal Replacement Energy 7/	1,922.4	1,922.4	1,922.4
Other Usable Secondary Energy 8/	940.5	940.5	940.5
System Annual Average Usable Energy	9,521.9	9,521.9	9,521.9
Average Annual Usable Energy Gain 9/	1,187.3	1,184.5	1,179.8
Canadian Share of Avg. Annual Energy Gain 5/	593.7	592.3	589.9

1/ Step II values were obtained from the AOP 93-42, 93-12, and 93-22 studies, respectively.
2/ Step III values were obtained from the AOP 93-13 study.
3/ From Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the estimated 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 System Annual Average Usable Energy.

TABLE 1

SUMMARY OF POWER REGULATIONS
FROM 1992-93 ASSURED OPERATING PLAN
FOR THE COMPUTATION OF CANADIAN ENTITLEMENT
TO DOWNSTREAM POWER BENEFITS

	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	AVERAGE ANNUAL GENERATION MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	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	99	3,008	185	111	102	3,008	282	156	102
Kerr	3	160	1,219	149	113	1,219	146	102	118	1,219	153	116	117
Thompson Falls	6	40		40	37		40	38	37		40	37	36
Noxon Rapids	5	554	231	536	149		554	134	203		554	156	204
Cabinet Gorge	4	227		227	104		227	91	120		227	103	120
Albeni Falls	3	49	1,155	24	25	1,155	25	24	24	1,155	19	21	25
Box Canyon	4	74		71	46		71	44	48		69	51	48
Grand Coulee	24	6,684	5,185	6,382	2,023	5,072	6,338	1,785	2,328	5,072	6,036	1,209	2,284
Chief Joseph	27	2,687		2,687	1,123		2,687	1,026	1,380		2,687	732	1,301
Wells	10	820		820	391		820	366	452		820	266	417
Rocky Reach	11	1,267		1,267	562		1,267	527	678		1,267	380	632
Rock Island	18	544		544	273		544	258	323		544	183	294
Wanapum	10	986		986	504		986	478	592		986	334	536
Priest Rapids	10	912		912	498		912	474	566		912	341	510
Brownlee	5	675	975	675	213	975	675	277	282	975	675	271	283
Oxbow	4	220		220	87		220	111	115		220	113	115
Ice Harbor	6	693		693	212		693	225	297		692	180	296
McNary	14	1,127		1,127	629		1,124	585	751		1,124	449	701
John Day	16	2,484	535	2,484	931		2,484	928	1,273		2,484	703	1,228
The Dalles	22+2F	2,076		2,076	734		2,076	713	976		2,076	565	952
Bonneville	18+2F	1,147		1,147	592		1,147	574	726		1,147	454	689
Kootenay Lake			649			649				649 1/			
Chelan	2	54	677	52	38	676	51	38	44	676	51	50	43
Coeur d'Alene Lake			223			223				223			
Total Base System Hydro		23,808	29,510	23,447	9,383	28,477	23,272	8,909	11,435	12,977	23,065	6,872	10,933
ADDITIONAL STEP I PROJECTS													
Libby	5	604	4,980	449	181								
Boundary	6	1,055		655	369								
Spokane River Plants	24	157	104	155	91								
Hells Canyon	3	450		423	170								
Dworshak	3	460	2,015	460	181								
Lower Granite	6	930		930	210								
Little Goose	6	930		930	210								
Lower Monumental	6	930		930	198								
Pelton, Rereg., and Round Butte	7	413	274	408	127								
Subtotal		5,929	7,373	5,340	1,737								
THERMAL RESOURCES 1/													
Small Existing Thermal Plants				1,690	263								
Centralia #1 & #2				1,280	1,027								
Jim Bridger #1, #2, #3, & #4				1,986	1,451								
Colstrip #1,#2,#3,#4				1,310	1,000								
Trojan				1,080	786								
Boardman				530	406								
Valmy				242	187								
WNP #2				1,100	792								
Total Thermal Resources				9,218	5,912		9,218	5,953			9,218	6,120	
RESERVES 2/				(2,443)	0		(1,972)	0			(1,671)	0	
TOTAL RESOURCES				35,562	17,032		30,518	14,862			30,612	12,992	
LOADS													
ESTIMATED LOAD PACIFIC NORTHWEST AREA				30,541	18,331		24,645	14,862			20,893	12,992	
Firm Exports				582	438								
Surplus Firm Exports				0	366								
Firm Imports				(407)	(38)								
Miscellaneous Contracts				(389)	(306)								
Other Coordinated Hydro		3,188	5,486	(2,663)	(1,034)								
Independent Hydro Resources		1,781	4,342	(1,383)	(756)								
Estimated Hydro Maintenance				1,365	31								
TOTAL STEP I LOADS				27,646	17,032								
SURPLUS				7,916	0		5,873	0			9,719	0	
CRITICAL PERIOD													
Starts:				September 1, 1928			September 1, 1943				September 16, 1936		
Ends:				February 29, 1932			April 30, 1945				April 15, 1937		
Length (Months)				42 Months			20 Months				7 Months		
Study Identification				93-41			93-42				93-13		

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 reserves 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.

TABLE 3

DETERMINATION OF LOADS FOR
1992-93 AOP STEP I, II, AND III STUDIES

LOAD OF THE PACIFIC NORTHWEST AREA						STEP I STUDY							STEP II STUDY		STEP III STUDY		
						ENERGY LOAD			PEAK LOAD								
Period	PNWA Area Energy Load aMW	Energy Load w/Exports 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Base Export aMW	Firm Surplus aMW	Total MWa	Base Exports MW	Firm Surplus MW	Total MW	Thermal Installations aMW	Total Load 2/ aMW	Hydro Load 3/ aMW	Total Load 2/ aMW	Hydro Load 3/ aMW	Period
Aug. 1-15	17074	17838	93.69	23526	72.58	396	0	17470	439	0	23965	6431	13780.4	7349.4	11682.7	5251.7	Aug. 1-15
Aug. 16-31	16996	17725	93.09	23526	72.24	361	0	17357	439	0	23965	6431	13693.1	7262.1	11608.7	5177.7	Aug. 16-31
Sept. 1-15	16661	17384	91.30	23897	69.72	355	347	17363	409	554	24860	6475	13429.7	6954.7	11385.3	4910.3	Sept. 1-15
Sept. 16-30	16631	17354	91.14	23897	69.59	355	347	17333	409	554	24860	6475	13406.5	6931.5	11365.7	4890.7	Sept. 16-30
October	17261	18004	94.56	25902	66.64	375	347	17983	473	554	26929	6426	13908.7	7482.7	11791.4	5365.4	October
November	18851	19608	102.98	27828	67.74	389	347	19587	527	554	28909	6545	15147.8	8602.8	12841.9	6296.9	November
December	20140	20932	109.93	29406	68.49	424	347	20911	533	554	30493	6538	16170.7	9632.7	13709.0	7171.0	December
January	20791	21590	113.39	30541	68.08	431	0	21222	582	0	31123	6546	16679.0	10133.0	14140.0	7594.0	January
February	20012	20796	109.22	29299	68.30	416	0	20428	541	0	29840	6549	16065.6	9516.6	13619.9	7070.9	February
March	18503	19289	101.31	27377	67.59	418	0	18921	462	0	27839	5914	14901.4	8987.4	12633.0	6719.0	March
April 1-15	17740	18647	97.93	26108	67.95	539	0	18279	631	0	26739	4545	14405.4	9860.4	12212.5	7667.5	April 1-15
April 16-30	17837	18730	98.37	26109	68.32	525	0	18362	631	0	26740	4093	14469.5	10376.5	12266.9	8173.9	April 16-30
May	17203	18227	95.73	25007	68.79	656	3200	21059	846	5107	30960	3078	14081.0	11003.0	11937.4	8859.4	May
June	17352	18192	95.54	24163	71.81	472	0	17824	699	0	24862	4520	14053.9	9533.9	11914.5	7394.5	June
July	17257	18105	95.09	24070	71.70	480	0	17737	459	0	24529	6424	13986.7	7562.7	11857.5	5433.5	July
Annual Average =		19040.4	100.00		69.11	444.1	387.8	19060.1				5811.5	14709.3	8897.8	12470.1	6658.6	Annual Avg.
Critical Period Avg =		19137.0			68.98	437.6	365.7	19134.6				5911.5	14862.4	8909.4	12991.9	6871.9	Crit.Per.Avg.
Step II CP Avg =		19238.6										5953.0					
Step III CP Avg=		19837.0										6120.0	Input 4/=	8909.4	Input 4/=	6871.9	
August 1-31		17781.5	93.39	23526	72.41	379	0	17414	439	0	23965	6431.0	13736.8	7305.8	11645.7	5214.7	Aug. 1-31
September 1-30		17369.0	91.22	23897	69.66	355	347	17348	409	554	24860	6475.0	13418.1	6943.1	11375.5	4900.5	Sept. 1-30
April 1-30		18688.5	98.15	26109	68.13	532	0	18321	631	0	26740	4319.0	14437.5	10118.5	12239.7	7920.7	Apr. 1-30

Notes:
1. The computation of the load shape for the Step II/III studies used the loads shown in column 2, which includes the base export loads and a 368 average MW firm surplus. The decision to exclude exports and firm surplus from PNWA loads was made too late to be included in the AOP93. Future studies will use the load shape of the Pacific Northwest Area in column 1.
2. 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.
3. The hydro load is equal to the total load minus the Step I study thermal installations.
4. 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 1992-93 AOP STUDIES

(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 in PNWA	3603.0	3603.0	3647.0	3675.0	3716.0	3711.0	3719.0	3720.0	3451.0	2259.0	1755.0	1133.0	2485.0	3596.0	3203.7
2. Total Thermal Resources outside PNWA	2828.0	2828.0	2828.0	2751.0	2828.0	2828.0	2828.0	2828.0	2463.0	2286.0	2338.0	1945.0	2035.0	2828.0	2607.9
3. Total Thermal Resources	6431.0	6431.0	6475.0	6426.0	6544.0	6539.0	6547.0	6548.0	5914.0	4545.0	4093.0	3078.0	4520.0	6424.0	5811.5
4. Minimum Thermal Generation	1965.0	1965.0	1965.0	1927.0	2192.0	2192.0	2192.0	2192.0	1783.0	1695.0	1469.0	1230.0	1447.0	1965.0	1884.5
5. Displaceable Thermal Resources	4466.0	4466.0	4510.0	4499.0	4352.0	4347.0	4355.0	4356.0	4131.0	2850.0	2624.0	1848.0	3073.0	4459.0	3927.1
SYSTEM SALES															
6. Firm Contract Sales	396.0	361.0	355.0	375.0	389.0	424.0	431.0	416.0	418.0	539.0	525.0	656.0	472.0	480.0	
7. Firm Surplus Sales	0.0	0.0	346.5	346.5	346.5	346.5	0.0	0.0	0.0	0.0	0.0	3200.0	0.0	0.0	
8. Total System Sales	396.0	361.0	701.5	721.5	735.5	770.5	431.0	416.0	418.0	539.0	525.0	3856.0	472.0	480.0	831.7
9. Uniform Average Annual System Sales	831.7	831.7	831.7	831.7	831.7	831.7	831.7	831.7	831.7	831.7	831.7	831.7	831.7	831.7	
PNW THERMAL DISPLACEMENT MARKET =	3634.3	3634.3	3678.3	3667.3	3520.3	3515.3	3523.3	3524.3	3299.3	2018.3	1792.3	1016.3	2241.3	3627.3	3095.4

NOTES:
Line 1 = Total Thermal located in the PNW.
Line 2 = Total Thermal not located in the PNW but meets Step I System Load (Colstrip + Valmy + Jim Bridger)
Line 3 = Total Thermal Resources from the Step I Study (Lines 1 + 2).
Line 4 = Minimum generation requirement for above resources.
Line 5 = Displaceable Thermal Resources from the Step I Study (Lines 3 - 4).
Line 6 = Sum of the Step I Study firm contract sales of energy exported to meet non-PNWA Loads.
Line 7 = Firm Surplus Energy Sales in the Step I Study assumed to be exported to PSW.
Line 8 = Net Sales (Lines 6 + 7).
Line 9 = Yearly Average Annual Sales, calculated from Line 8.
PNW Thermal Displacement Market = Displaceable Thermal Resources minus the Yearly Average of Net Sales (Lines 5 - 9).

TABLE 5

COMPARISON OF 1992-93 AOP STUDY TO RECENT AOP STUDIES

	1988-89	1989-90	1990-91	1991-92	1992-93
MICA TARGET OPERATION (ksfd or cfs)					
- AUG 1	3456.2	3456.2	3456.2	FULL	3456.2
- AUG 2	FULL	FULL	FULL	FULL	FULL
- SEP	FULL	FULL	FULL	FULL	FULL
- OCT	10000	10000	10000	FULL	FULL
- NOV	3122.2	3122.2	3122.2	3122.2	3246.2
- DEC	28000	26000	23000	23000	22000
- JAN	28000	26000	27000	23000	27000
- FEB	23000	23000	24000	23000	25000
- MAR	17000	17000	20000	18000	23000
- APR 1	15000	15000	15000	18000	27000
- APR 2	10000	10000	10000	18000	10000
- MAY	10000	10000	10000	10000	10000
- JUN	10000	10000	10000	10000	10000
- JUL	3356.2	3356.2	3356.2	3456.2	3256.2
CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)					
NOV 1928 (-41)	533.0	533.1	606.5	533.0	690.3
APR 1929 (-41)	6886.5	6767.9	7227.1	7049.3	7368.5
JUL 1929 (-41)	624.9	464.0	759.1	707.1	1036.3
AUG 1929 (-41)	13.8	8.1	135.9	183.3	560.0
NOV 1928 (-11)	251.6	351.2	538.7	526.7	690.3
JUL 1929 (-11)	471.2	375.6	761.7	708.0	1036.3
U.S. STEP I GAINS AND LOSSES (MW)					
-Firm Energy	-1	0	0	-0.2	0.0
-Dependable Capacity	-3	-10	2	0	-6.0
-Secondary Energy	-1	-9	-20	10.5	+16.8
BCH STEP I GAINS AND LOSSES (MW)					
-Firm Energy	52	72	26	12.1	+87.1
-Dependable Capacity	-23	-16	-1	-3	+1.0
-Secondary Energy	-46	-70	-12	-2.8	-63.2
HYDROREG SECONDARY LOAD (MW)					
- AUG 1	11827	11949	8927	10796	11070
- AUG 2	11844	11826	8895	10750	11070
- SEP	11677	11881	8701	10528	9981
- OCT	11852	11977	8936	10726	9981
- NOV	12701	11903	8819	10637	9864
- DEC	12923	12698	8838	10632	9857
- JAN	12961	12731	8853	10677	10996
- FEB	13017	12783	8909	10734	10990
- MAR	12442	12448	8624	10324	10757
- APR 1	11239	10917	8268	9885	10390
- APR 2	10576	10352	7831	9804	10164
- MAY	10054	9874	8394	10135	7156
- JUN	10737	10927	8542	10266	10615
- JUL	12064	12064	8926	10761	11081

TABLE 6

COMPARISON OF 1992-93 DDPB TO RECENT DDPB STUDIES

	1988-89	1989-90	1990-91	1991-92	1992-93
PNW AREA AVG. ANNUAL LOAD (MW)	20116	20026	18103	18449	18228
- Avg. Annual/Jan. Load (%)	84.31	84.26	87.52	86.97	87.67
- Avg. C.P. Load Factor (%) 1/	75.66	75.08	68.54	69.43	68.98
- Avg. Annual Firm Exports	82	186	333	376	444
- Avg. Annual Firm Surp. (MW)	-473	-632	492	239	388
THERMAL RESOURCES (MW)					
- January Peak Capability	11326	11547	9249	9249	9218
- C.P. Energy	7265	7229	5831	5800	5912
- Minimum Generation	1781	1793	1894	1862	1916
- System Export Sales	NA	NA	NA	NA	832
- Displaceable Market	5484	5436	3937	3938	3095
INSTALLED HYDRO CAPACITY (MW) 2/	34225	34578	34633	34584	29737
- Base System	23776	23808	23808	23808	23808
STEP I/II/III C.P. (MONTHS)	42.5/20/7	42.5/20/7	42/20/7	42/20/7	42/20/7
BASE STREAMFLOWS AT THE DALLES (cfs)					
- Step I Avg. Annual Streamflow	N.A.	174109	173996	175557	175456
- Step I C.P. Average	112207	112139	112054	112996	112920
- Step II C.P. Average 3/	97424	98777	98717	98193	99637
- Step III C.P. Average 3/	62343	62081	62502	62200	60661
CAPACITY BENEFITS (MW)					
- Step II C.P. Generation	8969.5	8965.8	8944.9	8903.8	8909.4
- Step III C.P. Generation	6969.7	6951.0	6960.7	6919.6	6871.9
- Step II Gain over Step III	1999.8	2014.8	1984.2	1984.2	2037.5
- CANADIAN ENTITLEMENT	1321.6	1341.8	1447.5	1428.9	1476.9
- Reduction due to Mica Reop.	0.0	0.0	0.0	0.0	0.0
- Benefit in Sales Agreement	1012.	1017.	1022.	932.	844.
ENERGY BENEFITS (Avg. MW)					
- Step II Firm Hydro	8733.4	8728.7	8773.1	8735.3	8898.2
- Step II Thermal Displacement	2079.9	2057.6	1701.0	1732.1	1327.0
- Step II Other Usable	272.3	284.8	403.1	396.8	484.0
- Step II Total Usable	11085.6	11071.1	10877.2	10864.2	10709.2
- Step III Firm Hydro	6279.7	6254.2	6452.2	6417.0	6659.0
- Step III Thermal Displacement	3026.4	2986.8	2402.3	2408.9	1922.4
- Step III Other Usable	689.7	697.3	861.6	863.7	940.5
- Step III Total Usable	9995.8	9938.3	9716.1	9689.6	9521.9
- CANADIAN ENTITLEMENT	544.9	566.4	580.6	587.3	593.7
- Reduction due to Mica Reop.	-2.8	-3.4	-2.7	-3.5	+1.4
- Entitlement in Sales Agreement	368.	349.	330.	318.	305.
STEP II PEAK CAPABILITY (MW)	32531	32810	30603	30611	30518
STEP II PEAK LOAD (MW)	25696	25596	24269	24215	24645
STEP III PEAK CAPABILITY (MW)	32394	32756	30613	30574	30612
STEP III PEAK LOAD (MW)	21756	21626	20413	20352	20893

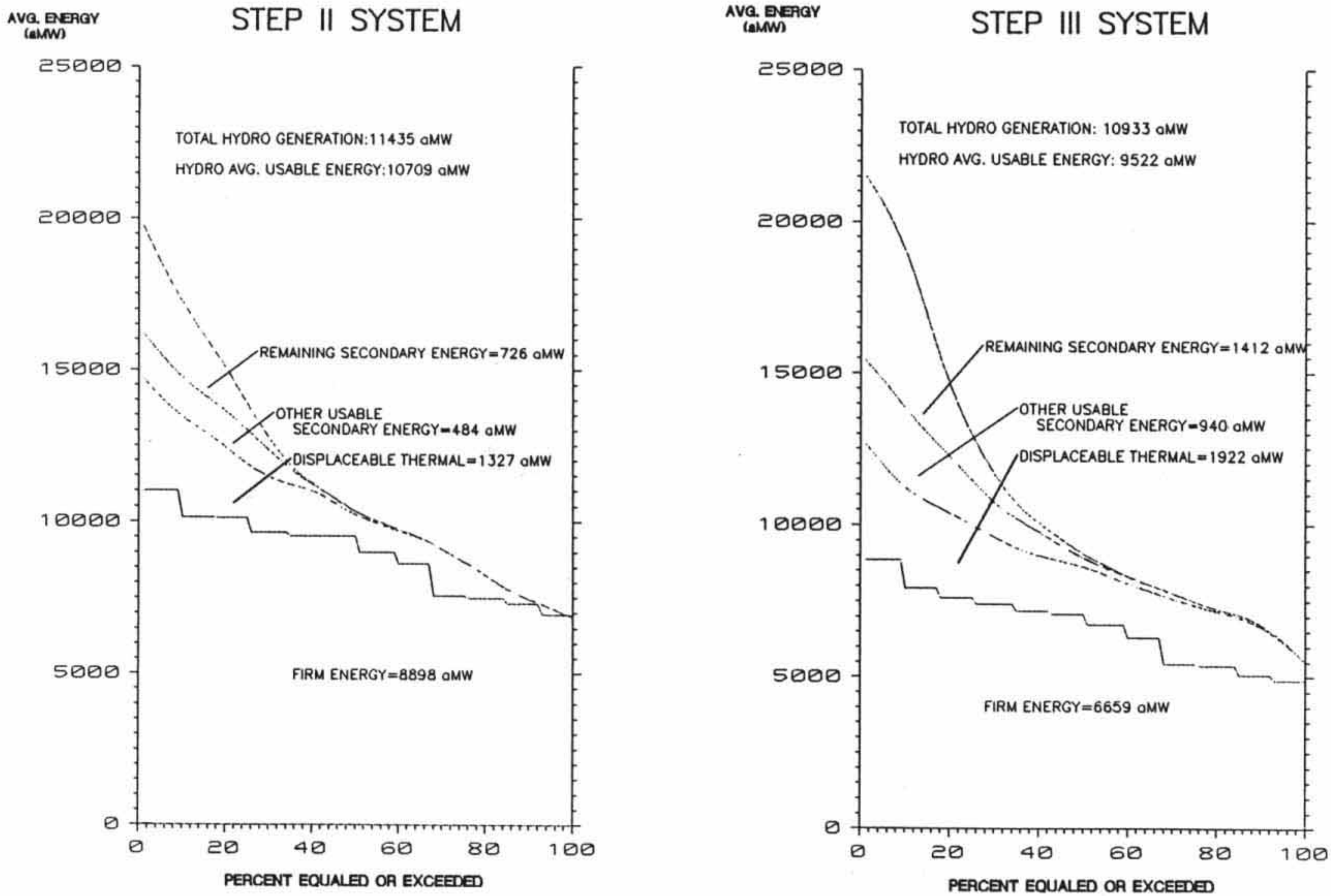
Notes: 1. The 1989 through 1992 studies included firm contract exports in the computation of the Step I average critical period load factor and the Step II/III study load shape.

2. Other coordinated hydro and independent hydro are now included as adjustments to the Step I load.

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

CHART 1

1992–93 DETERMINATION OF DOWNSTREAM POWER BENEFITS 30–YEAR HYDRO GENERATION – MW



DOWNSTREAM POWER BENEFIT 10709.2 – 9521.9 = 1187.3 AVG MW

CANADIAN ENTITLEMENT 1187.3 ÷ 2 = 593.7 AVG MW