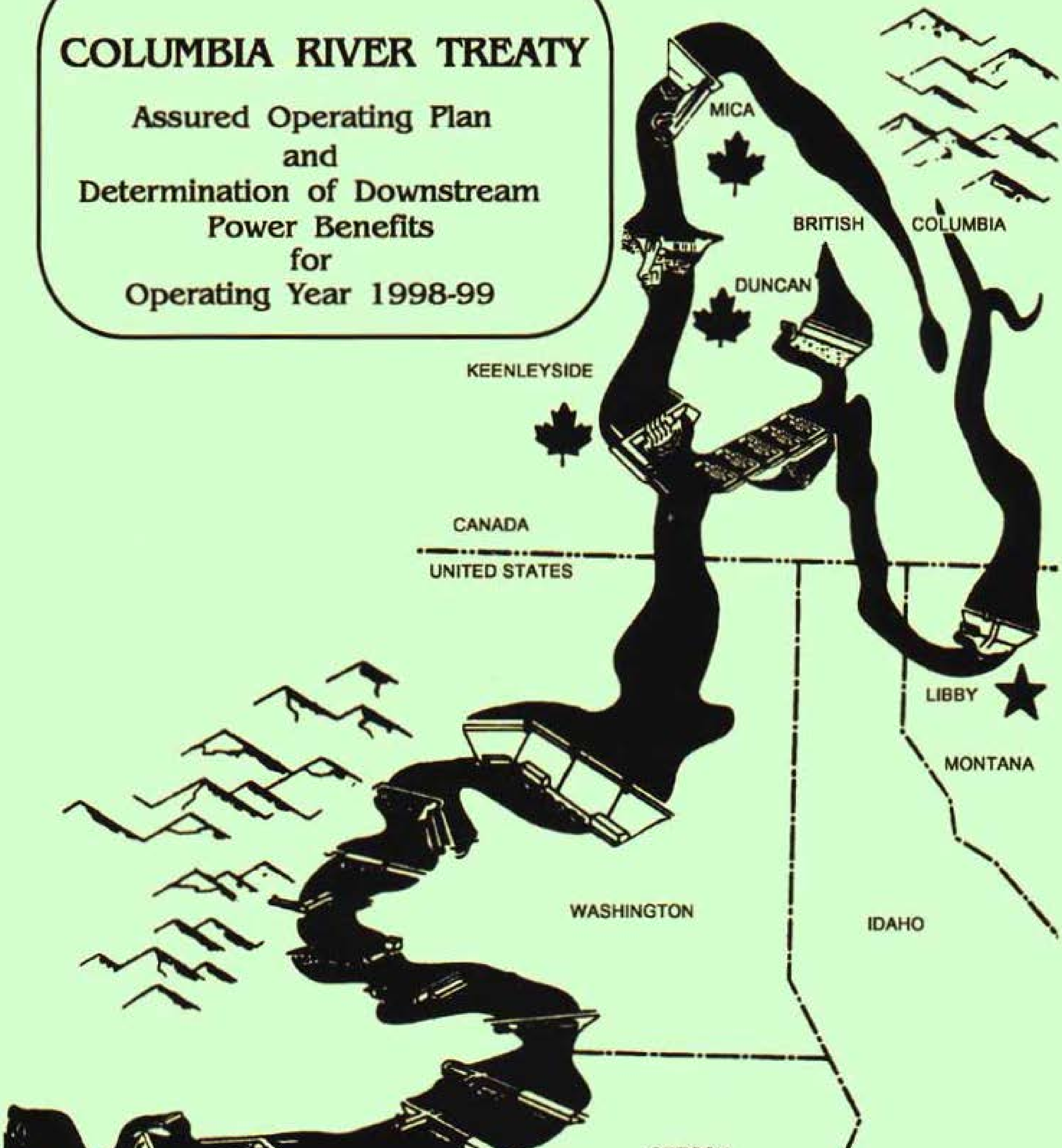
# COLUMBIA RIVER TREATY

## Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 1998-99




Columbia River Treaty Operating Committee

October 1994

# COLUMBIA RIVER TREATY
# HYDROELECTRIC OPERATING PLAN

# ASSURED OPERATING PLAN
# FOR OPERATING YEAR 1998-99

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# HYDROELECTRIC OPERATING PLAN
# ASSURED OPERATING PLAN
# FOR OPERATING YEAR 1998-99

October 1994

## 1. Introduction

The treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin (Treaty) requires that each year an Assured Operating Plan be agreed to by the Entities for the operation of the Columbia River Treaty storage in Canada during the sixth succeeding year. This plan will provide to the Entities information for the sixth succeeding year for planning the power systems in their respective countries which are dependent on or coordinated with the operation of the Canadian storage projects.

This Assured Operating Plan was prepared in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans[1] (POP) and in accordance with the Entity Agreements on:

- Principles[2] and on Changes to Procedures[3] for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, signed 28 July and 12 August 1988, respectively.
- Preparation of the 1998-99, 1999-00, and 2000-01 Assured Operating Plan and Determination of Downstream Power Benefit Studies[4].

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

The Assured Operating Plan consists of:

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

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

## 2. System Regulation Studies

In accordance with Annex A, Paragraph 7, of the Treaty, the Columbia River Treaty Operating Committee conducted system regulation studies reflecting Canadian storage operation for optimum generation in both Canada and the United States. Downstream power benefits were computed with the Canadian storage operation based on the operating rules specified herein. For this operation, there is a 4.1 aMW decrease in the Canadian Entitlement to annual average usable energy and a 0.4 MW decrease in the entitlement to dependable capacity when compared to the operation for optimum generation in the United States alone. These are within the limits specified by the Treaty.

System Regulation Studies for the Assured Operating Plan were based on 1998-99 estimated loads and resources in the United States Pacific Northwest System and resources in the

Columbia River Basin in British Columbia. The Entities agreed that the 1998-99 Assured Operating Plan would be based on a 30-year streamflow period and an operating year of 1 August to 31 July. Historical flows for the period August 1928 through July 1958, modified by estimated irrigation depletions for 1990 level, were used.[9]

The Critical Rule Curves for these studies were determined from the Bonneville Power Administration study of optimum power generation in both Canada and the United States. The study indicated a 42-month critical period for the United States system resulting from the low flows during the period from 1 September 1928 through 29 February 1932. With the exceptions of Brownlee and Dworshak, it was assumed that all reservoirs, both in the United States and Canada, were full at the beginning of the critical period except where minimum release requirements made this impossible.

In the studies, individual project flood control criteria were followed. Flood Control and Variable Refill Criteria are based on historical inflow volumes. Although only 7.0 million acre-feet of usable storage at Mica is committed for power operation purposes under the Treaty, the Columbia River Treaty Flood Control Operating Plan provides for the full draft of the total 12 million acre-feet of usable storage at Mica for on-call flood control purposes.

## 3. Development of the Assured Operating Plan

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

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

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

In the studies for the 1998-99 Assured Operating Plan, the Canadian storage operation was operated to achieve a weighted sum of the three quantities that was greater than the weighted sum achieved under an operation of Canadian storage for optimum generation in the United States of America alone.

In order to achieve a weighted value for the three quantities, the Columbia River Treaty Operating Committee agreed for the 1998-99 Assured Operating Plan that the three quantities would be assigned the following relative values:

| Quantity | Relative Value |
|---|---|
| Firm energy capability (aMW) | 3 |
| Dependable peaking capability (MW) | 1 |
| Average annual usable secondary energy (aMW) | 2 |

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

Table 2 shows the results from studies adopted for the 1998-99 Assured Operating Plan and from studies designed to achieve optimum generation in the United States alone.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Separate system regulation studies were developed reflecting (i) Canadian storage operation for optimum generation in both Canada and the United States, using the Mica Project operating criteria described in section 5(c) below, and (ii) Canadian storage operation for optimum generation in the United States alone. Using these Mica Project operating criteria, there is a 4.1 aMW decrease in entitlement to average annual energy and a 0.4 MW decrease in entitlement to dependable capacity compared to an operation for optimum generation in the United States alone.

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

## 4. Operating Rule Curves

The operation of Canadian storage during the 1998-99 Operating Year shall be guided by an Operating Rule Curve for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, and operating rules for specific projects. The Operating Rule Curve is derived from the various curves described below. These operating rule curves are first determined for the individual Canadian projects and then summed to yield the Composite Operating Rule Curve for the whole of Canadian storage. This is in accordance with Article VII(2) of the Protocol.

(a) Critical Rule Curve

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

(b) Refill Curve

The Refill Curve is a guide to operation of Canadian storage which defines the normal limit of storage draft to produce secondary energy in order to provide a high probability of refilling the storage. In general, the Operating Plan does not permit serving secondary loads at the risk of failing to refill storage and thereby jeopardizing the firm load carrying capability of the United States or Canadian systems during subsequent years. The end of the refill period is considered to be 31 July.

The Refill Curve is defined by two curves, the assured refill curve and the variable refill curve, as discussed in the following sections. In each case, adjustment is made for water required for refill of upstream reservoirs when applicable. Tabulations of the variable refill curves and outflow schedules used in determining the variable refill curves and assured refill curves for Duncan, Arrow, and Mica are provided in Tables 5 - 7, respectively.

(1) Assured Refill Curve

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

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

(2) Variable Refill Curve

The Variable Refill Curves give end-of-month storage contents for the period January through July required to refill Canadian storage during the refill period. They were based on historical inflow volumes and Power Discharge Requirements determined in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans.[1] The power discharge requirements used in the 1998-99 AOP are the same as those used in the 1997-1998 AOP. In the system regulation studies, the Power Discharge Requirement was made a function of the natural January - July runoff volume at The Dalles, Oregon. The Power Discharge Requirement used in computing the Variable Refill Curves was interpolated linearly between the values shown in Tables 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 Duncan, Arrow and Mica for the 30 years of historical record in Tables 5 - 7 illustrate the probable range of these curves based on historical conditions. In actual operation in 1998-99, the Power Discharge Requirements will be based on the forecast of unregulated runoff at The Dalles.

(c) Limiting Rule Curve (ECC Lower Limit)

The Limiting Rule Curves indicate end-of-month storage contents which must be maintained to protect the ability of the system to meet firm load during the period 1 January - 31 March in the event that the Variable Refill Curves permit storage to be emptied and sufficient natural flow is not available to carry the load prior to the start of the freshet. Such rule curves shall limit the Variable Refill Curve to be no lower than the Limiting Rule Curve. The Limiting Rule Curve is developed for 1936-37 water conditions. Limiting Rule Curves for Duncan, Arrow, and Mica are shown in Tables 5 - 7, respectively.

(d) Upper Rule Curve

The Upper Rule Curves indicate the end-of-month storage content to which each individual Canadian storage project shall be evacuated for flood control. The Upper Rule Curves used in the studies were based upon Flood Control Storage Reservation Diagrams contained in the Columbia River Treaty Flood Control Operating Plan[8] and analysis of system flood control simulations.[10] Flood control curves for Duncan, Arrow, and Mica for the 30-year study period are shown on Tables 8 - 10, respectively. Tables 9 and 10 reflect an agreed transfer of 2 million acre-feet of flood control storage space from Arrow to Mica. In actual operation, the Flood Control Storage Reservation Curves will be computed as outlined in the Flood Control Operating Plan, using the latest forecast of runoff available at that time.

(e) Definition of Operating Rule Curve

During the period 1 August through 31 December, the Operating Rule Curve is defined as the Critical Rule Curve for the first year of the critical period or the Assured Refill Curve, whichever is higher. During the period 1 January through 31 July, the Operating Rule Curve is defined as the higher of the Critical Rule Curve and the Assured Refill Curve; unless the Variable Refill Curve is lower than this value, then it is defined as the Variable Refill Curve. During the period 1 January through 31 March, it will not be lower than the Limiting Rule Curve. The Operating Rule Curve meets all requirements for flood control operation. Composite Operating Rule Curves for the whole of Canadian storage for 30 years of historical record are included as Table 11 to illustrate the probable future range of these curves based on historical conditions.

## 5. Operating Rules

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

The following rules, used in the 30-year System Regulation Study, will apply to the operation of Canadian storage in the 1998-99 Operating Year.

(a) Operation Above Operating Rule Curve

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

(b) Operation Below Operating Rule Curve

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

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

(c) Mica Project Operation

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

Under this Assured Operating Plan, Mica storage releases in excess of 7 million acre-feet that are required to maintain the Mica outflows specified under this plan will be retained in the Arrow reservoir, subject to flood control and other project operating criteria at Arrow. The total combined storage draft from Mica and Arrow will not exceed 14.1 million acre-feet, unless flood control criteria will not permit the additional Mica storage releases to be retained at Arrow. Should storage releases in excess of 14.1 million acre-feet be made, the target Mica operation will remain as specified in Table 1.

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile and Waneta have been included in the 1998-99 Assured Operating Plan and have been operated as run-of-river projects. Corra Linn and Kootenay Canal were also included in the study and operated in accordance with International Joint Commission rules for Kootenay Lake.

## 6. Implementation

The Entities have agreed that each year a Detailed Operating Plan will be prepared for the immediately succeeding operating year. Such Detailed Operating Plans are made under authority of Article XIV 2.(k) of the Columbia River Treaty which states:

"...the powers and the duties of the entities include:

(k) preparation and implementation of detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under the plans referred to in Annexes A and B."

The Detailed Operating Plan for 1998-99 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 1998-99 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 1998-99. Failing agreement on updating the data and/or criteria, the Detailed Operating Plan for 1998-99 will include the rule curves, Mica operating criteria, and other data and criteria provided in this Assured Operating Plan. Actual operation during the 1998-99 Operating Year shall be guided by the Detailed Operating Plan.

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

During the storage drawdown season, Canadian storage should not be drafted below its month-end point at any time during the month unless it can be conservatively demonstrated that sufficient inflow is available, in excess of the minimum outflow required to serve power demand, to refill the reservoir to its end-of-month value as required. During the storage evacuation and refill season, operation will be consistent with the Flood Control Operating Plan. When refill of Canadian storage is being guided by Flood Control Refill Curves,[8] such curves will be computed on a day-by-day basis using the residual volume-of-inflow forecasts depleted by the volume required for minimum outflow from each day through the end of the refill season.

## 7. Delivery of Canadian Entitlement

On 1 April 1998 and on 1 April 1999, the portions of the Canadian Entitlement to downstream power benefits related to the operation of Duncan and Arrow dams, respectively, cease to be covered by the Terms of the Sale of the Canadian Entitlement in the United States of America authorized by an Exchange of Notes between Canada and the United States of America dated 16 September 1964[12]. The Entities are currently preparing agreements for Delivery and Disposition of the Canadian Entitlement (beginning 1 April 1998) and it is expected that these agreements will be evidenced by an Exchange of Notes in 1995. Since these agreements have not yet been authorized by Canada and the United States, this Assured Operating Plan has been prepared on the basis that the portion of the Canadian Entitlement attributable to Duncan will be returned to Canada starting 1 April 1998, and the portion attributable to Arrow will be returned starting 1 April 1999.

The Treaty specifies return of the Canadian Entitlement at a point near Oliver, British Columbia, unless otherwise agreed by the Entities. Because no cross border transmission exists at any point on the Canada-United States of America boundary near Oliver, the Entities completed an agreement on Aspects of the Canadian Entitlement Return for 1 April 1998 through 31 March 2003,[13] executed 28 July 1992. This agreement describes the existing points of interconnection. The Entities have agreed that delivery of the lessor of 300 MW or 50% of the Canadian Entitlement attributable to Duncan and Arrow, net of 3% transmission loss, will be delivered at the Nelway Point of Delivery and the Waneta Point of Delivery. The balance of the Canadian Entitlement attributable to Duncan and Arrow, net of 3% transmission loss, will be delivered at the Blaine No. 1 Point of Delivery and the Blaine No. 2 Point of Delivery.

These arrangements cover the full 1 August 1998 through 31 July 1999 period that falls within the period covered by this Assured Operating Plan.

## 8. Capacity/Energy Entitlement Scheduling Guidelines

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

## 9. Summary of Changes From Previous Year

Data from the six most recent Assured Operating Plans are summarized in Table 12. Firm energy shifting was not included in the 1996-97, 1997-98, and 1998-99 operating plan studies. An explanation of the more important changes compared to last year's studies follows.

### (a) Loads and Resources

Loads for the 1998-99 AOP were based on the joint BPA/Northwest Power Planning Council November 1992 load forecast. The Pacific Northwest Area firm energy load increased by 92.3 annual aMW. The total exports, not including firm surplus energy, increased by 149.0 aMW. The firm surplus energy increased by 101.4 aMW. The increase in exports is due to an additional export sale to the southwest and the increased Canadian Entitlement Return.

The total energy capability of the thermal installations increased by 338.8 aMW. Major thermal resource changes included: 1) removal of the Trojan Nuclear plant from the resource stack, 2) combustion turbine resource increases of 827.2 aMW due to new facilities acquired to replace the loss of the Trojan Nuclear plant; 3) co-generation resource increases of 69.4 aMW due the addition of two new projects; and 4) thermal Non-Utility Generation (NUGs) increases of 52.2 aMW.

(b) Operating Procedures

The 1990 level modified base flows were used, with no additional depletion to the 1999 level, based on the recommendation of the Columbia River Water Management Group. Grand Coulee pumping adjustments and return flow, however, were included. The previous AOP/DDPB was based on the 1980 level modified base flows. Irrigation depletions were substantially less in the 1990 level modified flows, primarily in the Snake River basin above Brownlee.

The 1990 level modified flows resulted in increased flows in the Step I critical period study due to the lower level of irrigation depletions. Expected reductions in fish spill due to planned installation of fish bypass facilities at The Dalles and John Day by January 1998 resulted in increased Step I and II critical period generation at those projects.

Due to time constraints associated with completing the Entitlement Forecast Report, the Entities agreed not to complete refill studies for the 1998-99 Step I study. Power discharge requirements (PDRs) from the 1997-98 AOP/DDPB were used in the 1998-99 AOP/DDPB. A Step I refill test was performed which verified that the 1997-98 PDRs provided results that were within acceptable limits.

The Entities agreed to implement the PNCA section 6(c)(2)(c) provision which requires that in multiple year critical period studies no reservoir be drafted below its ARC by April 1, until all reservoirs have been drafted to their ARC's determined in PNCA section 7(b)(2). This caused the greatest change in the Step I study because the ARC for Grand Coulee at the end of March is empty and recent practice had been to ignore this PNCA provision in Step I but not Step II studies. The changed Grand Coulee operation was the major contributor to a reduction in the Step I critical period generation of almost 50 aMW.

Notable changes in non-power constraints included removal of the Inchelium Ferry minimum content constraint of 289.1 ksfd at Grand Coulee by the Bureau of Reclamation. New fisheries requirements were implemented at Dworshak which were reflected by beginning the Step I critical period 10 feet below full pool, drafting the reservoir empty only in the last few periods of the critical period, and essentially operating the reservoir on upper rule curve or minimum flow in the long-term study. Minimum and maximum outflow requirements at Kerr were also updated. Plant data for the lower Snake River projects (Lower Granite, Little Goose, Lower Monumental and Ice Harbor) were revised to allow the projects to be operated as reservoirs, although for this AOP they were operated in the traditional fashion as run-of-river projects. Because Dworshak was operated on a fixed operation, it was not included in the Step I refill test.

## REFERENCES


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

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

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

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

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

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

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

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

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

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

11 BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 99-41, dated 28 September 1993.

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

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

**TABLE 1**
**MICA PROJECT OPERATING CRITERIA**
**ASSURED OPERATING PLAN**

| Month | End of Previous Period Arrow Storage Content (ksfd) | —— Target Operation —— Period Average Outflow (cfs) | End-of-Period Treaty Content 1/ (ksfd) | Minimum Outflow (cfs) | Minimum Treaty Storage Content 2/ (ksfd) |
|---|---|---|---|---|---|
| August 1-15 | 1 300 - FULL | - | 3 456.2 | 10 000 | 0.0 |
| | 0 - 1 300 | 27 000 | | | |
| August 16-31 | 3 400 - FULL | - | 3 529.2 | 10 000 | 0.0 |
| | 800 - 3 400 | 24 000 | | | |
| | 0 - 800 | 28 000 | | | |
| September | 3 340 - FULL | - | 3 529.2 | 10 000 | 0.0 |
| | 600 - 3 340 | 22 000 | | | |
| | 0 - 600 | 28 000 | | | |
| October | 3 260 - FULL | 11 000 | | 10 000 | 0.0 |
| | 300 - 3 260 | 23 000 | | | |
| | 0 - 300 | 25 000 | | | |
| November | 3 420 - FULL | - | 3 256.2 | 13 000 | 0.0 |
| | 3 190 - 3 420 | 24 000 | | | |
| | 0 - 3 190 | 26 000 | | | |
| December | 3 400 - FULL | - | 2 676.2 | 21 000 | 723.2 |
| | 2 490 - 3 400 | 27 000 | | | |
| | 0 - 2 490 | 30 000 | | | |
| January | 3 050 - FULL | 24 000 | | 15 000 | 356.2 |
| | 2 100 - 3 050 | 28 000 | | | |
| | 0 - 2 100 | 30 000 | | | |
| February | 1 284 - FULL | 22 000 | | 15 000 | 0.0 |
| | 1 090 - 1 284 | 26 000 | | | |
| | 0 - 1 090 | 28 000 | | | |
| March | 1 050 - FULL | 22 000 | | 15 000 | 0.0 |
| | 910 - 1 050 | 25 000 | | | |
| | 0 - 910 | 27 000 | | | |
| April 1-15 | 0 - FULL | - | 86.2 | 10 000 | 0.0 |
| April 16-30 | 1 050 - FULL | - | 56.2 | 10 000 | 0.0 |
| | 0 - 1 050 | - | 0.0 | | |
| May | 320 - FULL | 10 000 | | 10 000 | 0.0 |
| | 70 - 320 | 13 000 | | | |
| | 0 - 70 | 20 000 | | | |
| June | 300 - FULL | 10 000 | | 10 000 | 0.0 |
| | 278 - 300 | - | 916.2 | | |
| | 0 - 278 | 26 000 | | | |
| July | 2 000 - FULL | - | 3 406.2 | 10 000 | 0.0 |
| | 790 - 2 000 | 19 000 | | | |
| | 0 - 790 | 27 000 | | | |

Notes:

1/ A maximum outflow of 34 000 cfs will apply if the target end-of-period storage content is less than 3529.2 ksfd in every month except April, May and June. For these periods, the maximum outflow is 32 000 cfs in April 1-15, 28 000 cfs in April 16-30, 30 000 cfs in May and 29 000 cfs in June.

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

## TABLE 2

## COMPARISON OF ASSURED OPERATING PLAN
## STUDY RESULTS

Study 99-41 provides Optimum Generation in Canada and in the United States.
Study 99-11 provides Optimum Generation in the United States only.

| | | Study No. 99-41 | Study No. 99-11 | Net Gain | Weight | Value |
|---|---|---|---|---|---|---|
| 1. | Firm Energy Capability (Avg. MW) | | | | | |
| | U.S. System 1/ | 12175.9 | 12181.0 | -5.1 | | |
| | Canada 2/, 3/ | 2789.1 | 2762.5 | 26.7 | | |
| | Total | 14965.0 | 14943.4 | 21.6 | 3 | 64.7 |
| 2. | Dependable Peaking Capacity (MW) | | | | | |
| | U.S. System 4/ | 30806.0 | 30779.0 | 27.0 | | |
| | Canada 2/, 5/ | 5374.0 | 5356.0 | 18.0 | | |
| | Total | 36180.0 | 36135.0 | 45.0 | 1 | 45.0 |
| 3. | Average Annual Usable Secondary Energy (Avg. MW) | | | | | |
| | U.S. System 6/ | 3131.3 | 3112.4 | 18.9 | | |
| | Canada 2/, 7/ | 238.1 | 256.6 | -18.5 | | |
| | Total | 3369.4 | 3369.0 | 0.4 | 2 | 0.8 |
| | | | Net Change in Value = | | | 110.5 |

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

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

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

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

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

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

TABLE 3

COLUMBIA RIVER TREATY
CRITICAL RULE CURVES
END OF MONTH CONTENTS IN KSFD
1998-99 OPERATING YEAR

MICA

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1ST YR | 3529.2 | 3529.2 | 3516.3 | 3428.4 | 3300.0 | 2965.5 | 2139.9 | 1487.7 | 1492.1 | 775.7 | 120.7 | 398.7 | 2046.2 | 3087.4 |
| 2ND YR | 3480.3 | 3523.2 | 3401.8 | 3185.9 | 2560.8 | 1777.4 | 1277.5 | 565.7 | 596.6 | 28.3 | 0.0 | 210.4 | 1274.8 | 2631.3 |
| 3RD YR | 3074.5 | 3194.9 | 3184.3 | 2955.4 | 2347.2 | 1594.6 | 803.2 | 282.0 | 288.8 | 0.0 | 0.4 | 0.0 | 411.2 | 1606.7 |
| 4TH YR | 1621.8 | 1440.9 | 1816.4 | 1417.5 | 350.2 | 3.0 | 9.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

ARROW

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1ST YR | 3579.6 | 3579.6 | 3557.3 | 3453.4 | 3338.6 | 2781.3 | 1853.7 | 1160.9 | 1202.7 | 675.9 | 390.2 | 953.5 | 2450.6 | 3330.6 |
| 2ND YR | 3525.4 | 3443.3 | 3475.9 | 3148.7 | 2768.2 | 2258.0 | 1285.5 | 1164.0 | 674.6 | 496.0 | 337.4 | 404.4 | 1238.3 | 2790.9 |
| 3RD YR | 2987.7 | 3171.5 | 3120.5 | 2738.2 | 2660.0 | 1747.1 | 1093.5 | 103.6 | 174.5 | 17.5 | 13.6 | 446.4 | 1376.6 | 1196.4 |
| 4TH YR | 1195.6 | 1213.9 | 684.1 | 528.7 | 980.1 | 719.2 | 345.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

DUNCAN

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1ST YR | 705.8 | 705.8 | 705.8 | 705.0 | 537.2 | 504.1 | 418.1 | 340.8 | 230.3 | 224.7 | 219.8 | 250.0 | 500.0 | 587.8 |
| 2ND YR | 630.0 | 667.1 | 577.8 | 460.0 | 232.5 | 243.0 | 222.0 | 214.1 | 222.8 | 232.0 | 242.3 | 140.0 | 228.5 | 339.9 |
| 3RD YR | 259.3 | 173.1 | 217.3 | 41.4 | 30.0 | 40.6 | 45.0 | 48.0 | 38.0 | 40.0 | 40.0 | 80.0 | 122.0 | 200.0 |
| 4TH YR | 150.0 | 70.0 | 75.0 | 55.0 | 2.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

COMPOSITE

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1ST YR | 7814.6 | 7814.6 | 7779.4 | 7586.8 | 7175.8 | 6250.9 | 4411.7 | 2989.4 | 2925.1 | 1676.3 | 730.7 | 1602.2 | 4996.8 | 7005.8 |
| 2ND YR | 7635.7 | 7633.6 | 7455.5 | 6794.6 | 5561.5 | 4278.4 | 2785.0 | 1943.8 | 1494.0 | 756.3 | 579.7 | 754.8 | 2741.6 | 5762.1 |
| 3RD YR | 6321.5 | 6539.5 | 6522.1 | 5735.0 | 5037.2 | 3382.3 | 1941.7 | 433.6 | 501.3 | 57.5 | 54.0 | 526.4 | 1909.8 | 3003.1 |
| 4TH YR | 2967.4 | 2724.8 | 2575.5 | 2001.2 | 1332.3 | 722.3 | 355.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

TABLE 4

COLUMBIA RIVER TREATY
ASSURED REFILL CURVES
END OF MONTH CONTENTS IN KSFD
1998-99 OPERATING YEAR

MICA

| 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1164.0 | 1728.2 | 2331.5 | 2509.8 | 2575.1 | 2591.6 | 2586.4 | 2099.0 | 1578.8 | 1349.0 | 1127.2 | 1315.1 | 2460.4 | 3529.2 |

ARROW

| 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 83.0 | 593.2 | 1195.7 | 1211.0 | 1365.3 | 2048.5 | 3142.2 | 3579.6 |

DUNCAN

| 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.4 | 81.3 | 147.6 | 178.3 | 195.8 | 207.0 | 217.2 | 218.0 | 222.8 | 231.5 | 231.2 | 345.0 | 540.9 | 705.8 |

TABLE 5

DUNCAN VARIABLE REFILL CURVE (KSFD)
1998-99 OPERATING YEAR

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1928-29 | | | | | | | 480.4 | 445.5 | 421.0 | 414.6 | 411.5 | 441.5 | 589.0 | 705.8 |
| 1929-30 | | | | | | | 478.7 | 443.5 | 418.7 | 412.0 | 422.9 | 462.2 | 600.4 | .. |
| 1930-31 | | | | | | | 423.3 | 389.3 | 368.0 | 366.5 | 369.8 | 411.1 | 589.0 | .. |
| 1931-32 | | | | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 109.6 | 442.3 | .. |
| 1932-33 | | | | | | | .. | .. | .. | .. | .. | 0.0 | 307.9 | .. |
| 1933-34 | | | | | | | .. | .. | .. | .. | 2.4 | 169.8 | 500.3 | .. |
| 1934-35 | | | | | | | 64.6 | 53.3 | 59.5 | 66.2 | 89.3 | 203.2 | 462.5 | .. |
| 1935-36 | | | | | | | 43.0 | 23.3 | 16.5 | 19.7 | 44.0 | 187.3 | 502.4 | .. |
| 1936-37 | | | | | | | 428.3 | 393.3 | 370.5 | 364.0 | 361.8 | 403.5 | 571.2 | .. |
| 1937-38 | | | | | | | 0.0 | 0.0 | 0.0 | 0.0 | 18.4 | 165.5 | 466.9 | .. |
| 1938-39 | | | | | | | 275.3 | 246.7 | 227.6 | 225.2 | 238.9 | 322.9 | 571.8 | .. |
| 1939-40 | | | | | | | 259.6 | 235.5 | 223.7 | 230.9 | 246.0 | 325.0 | 560.4 | .. |
| 1940-41 | | | | | | | 340.7 | 314.3 | 298.5 | 306.9 | 329.2 | 402.4 | 584.1 | .. |
| 1941-42 | | | | | | | 172.2 | 163.4 | 164.8 | 172.6 | 196.3 | 299.1 | 528.1 | .. |
| 1942-43 | | | | | | | 80.9 | 75.8 | 85.7 | 96.5 | 135.8 | 276.5 | 499.8 | .. |
| 1943-44 | | | | | | | 497.4 | 467.0 | 447.4 | 443.1 | 441.5 | 474.6 | 619.2 | .. |
| 1944-45 | | | | | | | 392.3 | 365.7 | 349.6 | 346.7 | 346.8 | 392.1 | 571.4 | .. |
| 1945-46 | | | | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 55.3 | 435.7 | .. |
| 1946-47 | | | | | | | .. | .. | .. | .. | .. | 98.4 | 448.4 | .. |
| 1947-48 | | | | | | | .. | .. | .. | .. | .. | 115.5 | 458.7 | .. |
| 1948-49 | | | | | | | 135.9 | 127.6 | 134.0 | 141.9 | 172.3 | 289.8 | 560.6 | .. |
| 1949-50 | | | | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 124.3 | 402.9 | .. |
| 1950-51 | | | | | | | .. | .. | .. | .. | .. | 89.9 | 433.9 | .. |
| 1951-52 | | | | | | | .. | .. | .. | .. | 22.1 | 174.9 | 479.0 | .. |
| 1952-53 | | | | | | | .. | .. | .. | .. | 19.2 | 153.2 | 445.3 | .. |
| 1953-54 | | | | | | | .. | .. | .. | .. | 0.0 | 16.9 | 376.0 | .. |
| 1954-55 | | | | | | | .. | .. | .. | .. | .. | 102.8 | 379.7 | .. |
| 1955-56 | | | | | | | .. | .. | .. | .. | .. | 63.5 | 431.6 | .. |
| 1956-57 | | | | | | | .. | .. | .. | .. | .. | 117.0 | 495.9 | .. |
| 1957-58 | | | | | | | .. | .. | .. | .. | .. | 54.2 | 447.7 | .. |
| ECC LOWER LIMIT | | | | | | | 0.0 | 0.0 | 0.0 | | | | | |
| POWER DISCHARGE REQUIREMENTS IN CFS FOR | | | | | | 80 MAF-- | 100 | 1000 | 1000 | 1000 | 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 | 1500 | 1500 | 2000 |

TABLE 6

ARROW VARIABLE REFILL CURVE (KSFD)
1998-99 OPERATING YEAR

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1928-29 | | | | | | | 1705.3 | 1802.3 | 2056.7 | 2093.8 | 2491.9 | 2656.4 | 3351.0 | 3579.6 |
| 1929-30 | | | | | | | 1185.9 | 308.9 | 542.7 | 614.5 | 1256.2 | 2047.9 | 3144.6 | " |
| 1930-31 | | | | | | | " | 634.9 | 912.6 | 971.6 | 1460.4 | 1882.7 | 3157.7 | " |
| 1931-32 | | | | | | | " | 308.9 | 0.0 | 0.0 | 0.0 | 1021.3 | 2765.9 | " |
| 1932-33 | | | | | | | " | " | " | " | 308.4 | 1295.7 | 2766.4 | " |
| 1933-34 | | | | | | | " | " | " | " | 71.8 | 1839.6 | 3284.5 | " |
| 1934-35 | | | | | | | " | " | " | " | 229.0 | 1079.9 | 2565.2 | " |
| 1935-36 | | | | | | | " | " | " | " | 0.0 | 1049.4 | 3087.2 | " |
| 1936-37 | | | | | | | 2025.5 | 2068.7 | 2323.2 | 2321.0 | 2728.2 | 2842.7 | 3443.0 | " |
| 1937-38 | | | | | | | 1185.9 | 380.7 | 374.5 | 434.1 | 811.9 | 1717.8 | 3058.3 | " |
| 1938-39 | | | | | | | " | 423.6 | 711.1 | 770.7 | 1348.0 | 1967.8 | 3506.6 | " |
| 1939-40 | | | | | | | " | 308.9 | 303.8 | 471.3 | 1122.3 | 1747.9 | 3222.5 | " |
| 1940-41 | | | | | | | " | 1318.2 | 1636.6 | 1812.9 | 2510.5 | 2937.5 | 3579.6 | " |
| 1941-42 | | | | | | | " | 534.1 | 941.9 | 1065.6 | 1647.6 | 2251.9 | 3287.4 | " |
| 1942-43 | | | | | | | 1897.7 | 1762.6 | 1724.6 | 1717.4 | 2159.5 | 3266.4 | 3579.6 | " |
| 1943-44 | | | | | | | 2537.0 | 2629.6 | 2905.9 | 2912.4 | 3320.9 | 3404.1 | " | " |
| 1944-45 | | | | | | | 1760.8 | 1914.3 | 2239.9 | 2312.8 | 2703.3 | 2839.4 | 3578.5 | " |
| 1945-46 | | | | | | | 1185.9 | 308.9 | 0.0 | 0.0 | 429.6 | 1487.3 | 3067.2 | " |
| 1946-47 | | | | | | | " | " | 126.4 | 172.8 | 593.8 | 1582.3 | 3012.3 | " |
| 1947-48 | | | | | | | " | " | 269.1 | 260.4 | 601.6 | 1572.4 | 3071.8 | " |
| 1948-49 | | | | | | | " | 322.4 | 741.6 | 934.9 | 1589.4 | 2577.5 | 3579.6 | " |
| 1949-50 | | | | | | | " | 308.9 | 214.9 | 251.9 | 604.7 | 1513.7 | 2754.1 | " |
| 1950-51 | | | | | | | " | 545.1 | 559.3 | 562.8 | 943.9 | 1858.4 | 3254.3 | " |
| 1951-52 | | | | | | | " | 552.9 | 548.2 | 558.1 | 886.1 | 1977.8 | 3368.6 | " |
| 1952-53 | | | | | | | " | 647.6 | 640.9 | 650.6 | 1073.9 | 2052.7 | 3211.6 | " |
| 1953-54 | | | | | | | " | 308.9 | 0.0 | 0.0 | 221.1 | 1195.8 | 2742.9 | " |
| 1954-55 | | | | | | | " | " | " | " | 16.2 | 955.1 | 2272.7 | " |
| 1955-56 | | | | | | | " | " | " | 13.6 | 398.5 | 1556.2 | 3068.2 | " |
| 1956-57 | | | | | | | " | " | 7.4 | 28.3 | 416.5 | 1397.0 | 3463.5 | " |
| 1957-58 | | | | | | | " | " | 0.0 | 0.0 | 184.8 | 1172.5 | 3037.0 | " |
| ECC LOWER LIMIT | | | | | | | 1185.9 | 308.9 | 0.0 | | | | | |
| POWER DISCHARGE REQUIREMENTS IN CFS FOR | | | | | | 80 MAF-- | 5000 | 10000 | 10000 | 15000 | 15000 | 30000 | 30000 | 30000 |
| JANUARY - JULY, VOLUME RUNOFF AT THE DALLES | | | | | | 95 MAF-- | 5000 | 5000 | 5000 | 5000 | 5000 | 15000 | 25000 | 25000 |
| FOR VARIABLE REFILL CALCULATION | | | | | | 110 MAF-- | 5000 | 5000 | 5000 | 5000 | 5000 | 8000 | 35000 | 35000 |
| FOR ASSURED REFILL CALCULATION | | | | | | | 5000 | 5000 | 5000 | 25000 | 25000 | 40000 | 40000 | 40000 |

TABLE 7

MICA VARIABLE REFILL CURVE (KSFD)
1998-99 OPERATING YEAR

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1928-29 | | | | | | | 3529.2 | 3529.2 | 3383.2 | 3182.3 | 3012.9 | 2600.7 | 2985.8 | 3529.2 |
| 1929-30 | | | | | | | 3208.6 | 2727.5 | 2309.0 | 2127.6 | 2090.2 | 1988.1 | 2701.6 | " |
| 1930-31 | | | | | | | 3468.1 | 2995.9 | 2573.2 | 2369.8 | 2262.9 | 2008.2 | 2776.8 | " |
| 1931-32 | | | | | | | 959.4 | 467.7 | 423.0 | 381.3 | 515.8 | 1076.1 | 2410.7 | " |
| 1932-33 | | | | | | | " | 448.4 | 325.2 | 278.0 | 375.0 | 940.7 | 2231.2 | " |
| 1933-34 | | | | | | | " | " | 52.5 | 0.0 | 0.0 | 646.3 | 2463.3 | " |
| 1934-35 | | | | | | | 1903.2 | 1660.3 | 1500.9 | 1426.5 | 1395.0 | 1537.0 | 2477.6 | " |
| 1935-36 | | | | | | | 1897.5 | 1615.8 | 1408.1 | 1295.7 | 1278.6 | 1525.7 | 2751.9 | " |
| 1936-37 | | | | | | | 3529.2 | 3529.2 | 3336.0 | 3124.3 | 3003.2 | 2614.4 | 3018.1 | " |
| 1937-38 | | | | | | | 959.4 | 741.6 | 697.3 | 658.3 | 759.0 | 1289.4 | 2496.1 | " |
| 1938-39 | | | | | | | 3272.2 | 2868.5 | 2459.5 | 2282.2 | 2197.7 | 2031.7 | 3009.6 | " |
| 1939-40 | | | | | | | 3064.2 | 2611.6 | 2219.7 | 2036.5 | 1974.1 | 1824.6 | 2769.4 | " |
| 1940-41 | | | | | | | 3529.2 | 3198.7 | 2795.7 | 2611.4 | 2586.0 | 2388.5 | 2999.6 | " |
| 1941-42 | | | | | | | 2416.5 | 2173.5 | 1988.8 | 1885.1 | 1851.2 | 1961.7 | 2807.5 | " |
| 1942-43 | | | | | | | 1347.1 | 1212.9 | 1171.1 | 1112.9 | 1284.2 | 1839.9 | 2692.7 | " |
| 1943-44 | | | | | | | 3529.2 | 3529.2 | 3441.4 | 3232.7 | 3089.8 | 2721.6 | 3156.8 | " |
| 1944-45 | | | | | | | " | " | 3276.8 | 3102.4 | 2955.7 | 2603.5 | 3060.5 | " |
| 1945-46 | | | | | | | 959.4 | 448.4 | 52.5 | 0.0 | 12.2 | 676.3 | 2357.8 | " |
| 1946-47 | | | | | | | " | " | 306.4 | 274.1 | 401.6 | 1036.3 | 2475.7 | " |
| 1947-48 | | | | | | | " | " | 56.0 | 0.0 | 106.8 | 735.4 | 2314.4 | " |
| 1948-49 | | | | | | | 2189.5 | 2054.9 | 1996.8 | 1956.3 | 1997.8 | 2294.1 | 3172.7 | " |
| 1949-50 | | | | | | | 959.4 | 448.4 | 348.7 | 284.4 | 403.1 | 958.5 | 2125.7 | " |
| 1950-51 | | | | | | | " | " | 419.7 | 373.1 | 518.8 | 1078.7 | 2487.2 | " |
| 1951-52 | | | | | | | " | 807.9 | 758.7 | 688.2 | 797.0 | 1376.7 | 2634.5 | " |
| 1952-53 | | | | | | | 1393.3 | 1267.5 | 1228.1 | 1180.1 | 1236.4 | 1626.1 | 2648.6 | " |
| 1953-54 | | | | | | | 959.4 | 448.4 | 52.5 | 0.0 | 52.6 | 650.8 | 2097.8 | " |
| 1954-55 | | | | | | | 1341.1 | 1243.3 | 1220.0 | 1204.9 | 1243.4 | 1575.7 | 2431.1 | " |
| 1955-56 | | | | | | | 959.4 | 448.4 | 257.0 | 195.4 | 319.6 | 975.7 | 2401.7 | " |
| 1956-57 | | | | | | | " | 462.8 | 433.1 | 383.5 | 505.1 | 1062.6 | 2732.3 | " |
| 1957-58 | | | | | | | " | 448.4 | 421.4 | 386.0 | 504.3 | 1036.7 | 2534.6 | " |
| ECC LOWER LIMIT | | | | | | | 959.4 | 448.4 | 52.5 | | | | | |

| | | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|
| POWER DISCHARGE REQUIREMENTS IN CFS FOR | 80 MAF-- | 3000 | 15000 | 15000 | 15000 | 20000 | 30000 | 30000 | 25000 |
| JANUARY - JULY, VOLUME RUNOFF AT THE DALLES | 95 MAF-- | 3000 | 3000 | 3000 | 3000 | 10000 | 10000 | 20000 | 20000 |
| FOR VARIABLE REFILL CALCULATION | 110 MAF-- | 3000 | 3000 | 3000 | 5000 | 5000 | 5000 | 15500 | 15500 |
| FOR ASSURED REFILL CALCULATION | | 3000 | 20000 | 20000 | 20000 | 22000 | 22000 | 22000 | 22000 |

TABLE 8

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
1998-99 OPERATING YEAR
KSFD

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | 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 | " |

TABLE 9

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
1998-99 OPERATING YEAR
KSFD

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | 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
1998-99 OPERATING YEAR
KSFD

| | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | 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 | " | " | " | " | " | " | " | " | " | " | " | " | " | " |

TABLE 11

COLUMBIA RIVER TREATY
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS IN KSFD
1998-99 OPERATING YEAR

| FLOW YEAR | 15-Aug | 31-Aug | SEP | OCT | NOV | DEC | JAN | FEB | MAR | 15-Apr | 30-Apr | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1928-29 | 7814.6 | 7814.6 | 7779.4 | 7586.8 | 7175.8 | 6250.9 | 4709.8 | 3600.7 | 3011.8 | 2791.5 | 2723.7 | 3708.6 | 6143.5 | 7814.6 |
| 1929-30 | " | " | " | " | " | " | 4190.4 | 2748.7 | 2351.8 | 2195.0 | 2614.6 | 3708.0 | " | " |
| 1930-31 | " | " | " | " | " | " | " | 3074.7 | 2721.7 | 2552.1 | 2723.7 | 3542.8 | " | " |
| 1931-32 | " | " | " | " | " | " | 2145.3 | 776.6 | 423.0 | 381.3 | 515.8 | 2207.0 | 5618.9 | " |
| 1932-33 | " | " | " | " | " | " | " | 757.3 | 325.2 | 278.0 | 683.4 | 2236.4 | 5305.5 | " |
| 1933-34 | " | " | " | " | " | " | " | " | 52.5 | 0.0 | 74.2 | 2655.7 | 6102.9 | " |
| 1934-35 | " | " | " | " | " | " | 3153.7 | 2022.5 | 1560.4 | 1415.2 | 1445.5 | 2598.2 | 5488.1 | " |
| 1935-36 | " | " | " | " | " | " | 3126.4 | 1948.0 | 1424.6 | 1315.4 | 1171.2 | 2551.8 | 6050.0 | " |
| 1936-37 | " | " | " | " | " | " | 4858.2 | 3600.7 | 3011.8 | 2791.5 | 2723.7 | 3708.6 | 6143.5 | " |
| 1937-38 | " | " | " | " | " | " | 2145.3 | 1122.3 | 1071.8 | 1092.4 | 1589.3 | 3172.7 | 5985.6 | " |
| 1938-39 | " | " | " | " | " | " | 4047.6 | 2769.3 | 2517.5 | 2344.9 | 2706.4 | 3605.8 | 6143.5 | " |
| 1939-40 | " | " | " | " | " | " | 4031.9 | 2643.4 | 2106.3 | 2051.2 | 2480.7 | 3388.0 | " | " |
| 1940-41 | " | " | " | " | " | " | 4113.0 | 3574.2 | 3011.8 | 2791.5 | 2723.7 | 3708.6 | " | " |
| 1941-42 | " | " | " | " | " | " | 3774.6 | 2796.5 | 2685.5 | 2587.2 | 2688.8 | 3662.7 | 6130.7 | " |
| 1942-43 | " | " | " | " | " | " | 3281.7 | 2449.6 | 2459.5 | 2420.4 | 2628.3 | 3640.1 | 6102.4 | " |
| 1943-44 | " | " | " | " | " | " | 4858.2 | 3600.7 | 3011.8 | 2791.5 | 2723.7 | 3708.6 | 6143.5 | " |
| 1944-45 | " | " | " | " | " | " | 4739.5 | " | " | " | " | " | " | " |
| 1945-46 | " | " | " | " | " | " | 2145.3 | 757.3 | 52.5 | 0.0 | 441.8 | 2218.9 | 5860.7 | " |
| 1946-47 | " | " | " | " | " | " | " | " | 432.8 | 446.9 | 995.4 | 2717.0 | 5921.1 | " |
| 1947-48 | " | " | " | " | " | " | " | " | 325.1 | 260.4 | 708.4 | 2423.3 | 5844.9 | " |
| 1948-49 | " | " | " | " | " | " | 3511.3 | 2504.9 | 2454.4 | 2425.8 | 2664.8 | 3653.4 | 6143.5 | " |
| 1949-50 | " | " | " | " | " | " | 2145.3 | 757.3 | 563.6 | 536.3 | 1007.8 | 2596.5 | 5282.7 | " |
| 1950-51 | " | " | " | " | " | " | " | 993.5 | 979.0 | 935.9 | 1462.7 | 3027.0 | 6036.5 | " |
| 1951-52 | " | " | " | " | " | " | " | 1360.8 | 1306.9 | 1246.3 | 1705.2 | 3467.8 | 6081.6 | " |
| 1952-53 | " | " | " | " | " | " | 2579.2 | 1915.1 | 1869.0 | 1830.7 | 2220.3 | 3516.8 | 6047.9 | " |
| 1953-54 | " | " | " | " | " | " | 2145.3 | 757.3 | 52.5 | 0.0 | 273.7 | 1863.5 | 5216.7 | " |
| 1954-55 | " | " | " | " | " | " | 2527.0 | 1552.2 | 1220.0 | 1204.9 | 1143.4 | 2373.0 | 5083.5 | " |
| 1955-56 | " | " | " | " | " | " | 2145.3 | 757.3 | 257.0 | 209.0 | 718.1 | 2595.4 | 5826.7 | " |
| 1956-57 | " | " | " | " | " | " | " | 771.7 | 440.5 | 411.8 | 921.6 | 2576.6 | 6098.5 | " |
| 1957-58 | " | " | " | " | " | " | " | 757.3 | 421.4 | 386.0 | 689.1 | 2263.4 | 5945.1 | " |

## TABLE 12

### COMPARISON OF RECENT ASSURED OPERATING PLAN STUDIES

| | 1993-94 | 1994-95 | 1995-96 | 1996-97 | 1997-98 | 1998-99 |
|---|---|---|---|---|---|---|
| **MICA TARGET OPERATION (ksfd or cfs)** | | | | | | |
| - AUG 1 | 3456.2 | 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 | 10000.0 | 3428.4 | 3428.4 | 14000.0 | 15000.0 | 11000.0 |
| - NOV | 19000.0 | 22000.0 | 22000.0 | 19000.0 | 19000.0 | 3256.2 |
| - DEC | 22000.0 | 24000.0 | 24000.0 | 23000.0 | 23000.0 | 2676.2 |
| - JAN | 26000.0 | 27000.0 | 27000.0 | 24000.0 | 24000.0 | 24000.0 |
| - FEB | 25000.0 | 25000.0 | 25000.0 | 20000.0 | 22000.0 | 22000.0 |
| - MAR | 22000.0 | 25000.0 | 25000.0 | 19000.0 | 19000.0 | 22000.0 |
| - APR 1 | 25000.0 | 24000.0 | 24000.0 | 156.2 | 106.2 | 86.2 |
| - APR 2 | 18000.0 | 14000.0 | 14000.0 | 0.0 | 0.0 | 56.2 |
| - MAY | 10000.0 | 10000.0 | 10000.0 | 10000.0 | 10000.0 | 10000.0 |
| - JUN | 10000.0 | 10000.0 | 10000.0 | 10000.0 | 10000.0 | 10000.0 |
| - JUL | 3256.2 | 3356.2 | 3356.2 | 3356.2 | 3356.2 | 3406.2 |
| **CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)** | | | | | | |
| NOV 1928 (-41) | 761.6 | 1272.6 | 1272.7 | 1481.7 | 922.2 | 638.8 |
| APR 1929 (-41) | 7754.1 | 7801.6 | 7801.6 | 7708.8 | 7727.7 | 7083.9 |
| JUL 1929 (-41) | 1139.5 | 1140.5 | 1140.5 | 1028.6 | 951.2 | 808.8 |
| AUG 1929 (-41) | 983.4 | 1060.4 | 1060.4 | 483.2 | 864.3 | 181.0 |
| NOV 1928 (-11) | 501.7 | 1275.3 | 1275.3 | 1483.6 | 923.3 | 642.0 |
| JUL 1929 (-11) | 1143.0 | 1142.8 | 1142.8 | 1036.6 | 955.2 | 830.8 |
| **STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)** | | | | | | |
| - U.S. Firm Energy | -1.4 | -4.4 | -4.4 | -2.0 | -0.9 | -5.1 |
| - U.S. Dependable Capacity | 3.0 | 2.0 | 2.0 | 3.0 | -4.0 | 27.0 |
| - U.S. Secondary Energy | -8.1 | 2.9 | 2.9 | 1.2 | 13.9 | 18.9 |
| - BCH Firm Energy | 40.1 | 56.0 | 56.0 | 36.0 | 46.7 | 26.7 |
| - BCH Dependable Capacity | -14.0 | 16.0 | 16.0 | -10.0 | 19.0 | 18.0 |
| - BCH Secondary Energy | -27.0 | -38.3 | -38.3 | -36.9 | -43.5 | -18.5 |
| **HYDROREG SECONDARY LOAD (MW)** | | | | | | |
| - AUG 1 | 10655 | 11475 | 11475 | 14510 | 14547 | 15568 |
| - AUG 2 | 10655 | 11475 | 11475 | 14396 | 14416 | 15422 |
| - SEP | 10092 | 11466 | 11466 | 14147 | 13878 | 14883 |
| - OCT | 10237 | 12021 | 12021 | 14616 | 14674 | 15594 |
| - NOV | 10083 | 12272 | 12272 | 15412 | 15411 | 16347 |
| - DEC | 10074 | 12443 | 12443 | 15951 | 15835 | 16578 |
| - JAN | 10914 | 12633 | 12633 | 16000 | 15832 | 16598 |
| - FEB | 10765 | 12641 | 12641 | 15884 | 15841 | 16638 |
| - MAR | 10405 | 11909 | 11909 | 15031 | 15160 | 15942 |
| - APR 1 | 10235 | 11817 | 11817 | 13840 | 14438 | 15523 |
| - APR 2 | 10933 | 11573 | 11573 | 13267 | 14391 | 15513 |
| - MAY | 7114 | 8114 | 8114 | 10734 | 10297 | 10960 |
| - JUN | 10079 | 11236 | 11236 | 14260 | 11748 | 11120 |
| - JUL | 10740 | 11590 | 11590 | 14648 | 14843 | 15529 |

# COLUMBIA RIVER TREATY
# DETERMINATION OF DOWNSTREAM POWER BENEFITS

## FOR THE ASSURED OPERATING PLAN
## FOR OPERATING YEAR 1998-99

# COLUMBIA RIVER TREATY
# DETERMINATION OF DOWNSTREAM POWER BENEFITS
# FOR THE ASSURED OPERATING PLAN
# FOR OPERATING YEAR 1998-99

## Preface to the 1998-99 DDPB

The Determination of Downstream Power Benefits (DDPB) for the Assured Operating Plan (AOP) for operating year 1998-99 presents both a U.S. and Canadian determination of the dependable capacity component of the Canadian Entitlement. Two determinations of the Capacity Entitlement are presented because the Entities have been unable to agree on a single interpretation of the definition of "critical stream flow period" in Article I, paragraph 1.(d), of the Treaty.

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

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

In order to proceed with completion of the 1998-99 AOP/DDPB prior to the Exchange of Notes required between the U.S. and Canadian federal governments to approve the capacity buydown provision, the Entities have agreed to prepare this document without reference to the capacity buydown provision and consequently two values for the Capacity Entitlement are displayed throughout the document reflecting the two interpretations of "critical stream flow period."

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

<u>Discretionary Draft for Power</u> - Under this interpretation, the Step III critical stream flow period is deemed to start when an initial draft, in excess of drafts necessary to meet flood control requirements and/or non-power requirements is required from reservoir storage to meet firm load

requirements. Using this interpretation, the Step III critical period starts 1 November 1936. The Step III critical period ends on 15 April 1937, for a duration of 5.5 months.

Draft for Power - Under this interpretation, the Step III critical stream flow period is deemed to start when an initial draft, in excess of drafts necessary to meet flood control requirements, is required from reservoir storage to meet firm load requirements. Using this interpretation, the Step III critical period begins 1 October 1936. The Step III critical period ends on 15 April 1937, for a duration of 6.5 months.

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

**1998-99 DDPB**
**Joint Optimum Studies**

| Critical Stream Flow Period Definition | Proposed by | Capacity Entitlement |
|---|---|---|
| Discretionary Draft for Power | U.S. | 1324.7 MW |
| Draft for Power | Canada | 1514.7 MW |
| Difference | ⇒ | 190.0 MW |

The Entities have agreed to compute Energy Entitlement based on the Discretionary Draft for Power interpretation ( the difference in Energy Entitlement resulting from the different critical stream flow period definitions is less than 2 aMW).

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**DETERMINATION OF DOWNSTREAM POWER BENEFITS
FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1998-99**

October 1994

## 1. Introduction

The treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin (Treaty) requires that downstream power benefits from the operation of Canadian Treaty storage be determined in advance by the two Entities. The purpose of this document is to describe the results of those downstream power benefit computations developed from the 1998-99 Assured Operating Plan (AOP).

The procedures followed in the benefit studies are those provided in Annex A, Paragraph 7, and Annex B of the Treaty; in Articles VIII, IX, and X of the Protocol; in the Entity Agreement on Resolution of Assured Operating Plan and Determination of Downstream Power Benefit Issues for the 1998-99, 1999-00, and 2000-01 AOP/DDPB, signed XX September 1994, in the Entity Agreements, signed 28 July and 12 August 1988, on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies (1988 Entity Agreements); and in the document, "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated December 1991.

The Canadian Entitlement Benefits were computed from the following studies:

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

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

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

As part of the determination of downstream power benefits for the operating year 1998-99, separate determinations were carried out relating to the limit of year-to-year change in benefits attributable to the operation of Canadian Treaty storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America (joint optimum).

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

## 2. Results of Canadian Entitlement Computations

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

| | | |
|---|---|---|
| Dependable Capacity | | |
| - Discretionary Draft for Power interpretation | = | 1324.7 MW |
| - Draft for Power interpretation | = | 1514.7 MW |
| Average Annual Energy | = | 562.7 aMW |

## 3. Computation of Maximum Allowable Reduction in Downstream Power Benefits

In accordance with the Treaty Annex A, Paragraph 7 and Part III, Paragraph 15c(2) of POP, the computation of the maximum allowable reduction in downstream power benefits and the resulting minimum permitted Canadian Entitlement to downstream power benefits for the 1998-99 operating year are based on the formula X - (Y - Z).

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

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

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

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

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

The quantities X and Y were computed in the 1997-98 DDPB. The quantity Z, which is computed from one-half of the downstream power benefits determined for 15 maf of Canadian Treaty storage operated for optimum power generation in the United States of America, is computed in Table 5.

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

Dependable Capacity
- Discretionary Draft for Power interpretation
  = 1229.6 - (1229.6 - 1299.7) = 1299.7 MW
- Draft for Power interpretation
  = 1229.6 - (1229.6 - 1489.7) = 1489.7 MW

Average Annual Energy = 553.3 - ( 556.1 - 557.0) = 554.2 aMW

The computed Canadian Entitlement exceeds these amounts.

**4. Effect on Sale of Canadian Entitlement**

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

The studies developed for this sale included the assumption of operation of Treaty storage only for optimum power generation downstream in the United States of America. The Canadian Entitlement determined from the 1998-99 Assured Operating Plan for this condition would have been:

| | | |
|---|---|---|
| Dependable Capacity | | |
| - Discretionary Draft for Power interpretation | = | 1325.1 MW |
| - Draft for Power interpretation | = | 1515.1 MW |
| Average Annual Usable Energy | = | 566.8 aMW |

Because the 1998-99 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 decrease in Canadian Entitlement of 4.1 aMW of average annual usable energy and a decrease in dependable capacity of 0.4 MW under the Discretionary Draft for Power interpretation (Note: because the capacity differentials are the same under either critical stream flow period interpretation, only the Discretionary Draft for Power value is displayed for simplicity).

Since the sale of the downstream power benefits attributable to Duncan expires 31 March 1998, the United States Entity is entitled to that portion of the decrease in Canadian Entitlement attributed to Arrow and Mica. The decrease of the Canadian Entitlement attributed to Arrow and Mica is computed by multiplying the decrease in Canadian Entitlement by the ratio of Arrow and Mica storage (14.1 maf) to the whole of Canadian storage (15.5 maf). The value is computed to be:

Capacity Payment = 0.4 MW * (14.1 maf/15.5 maf) = 0.4 MW
Energy Payment = 4.1 aMW * (14.1 maf/15.5 maf) = 3.7 aMW

Accordingly, the Entities are agreed that the United States Entity is entitled to receive 3.7 aMW of energy, and 0.4 MW of dependable capacity, during the period 1 April 1998 through 31 March 1999, from B.C. Hydro & Power Authority, in accordance with Sections 7 and 10 of CEPA.

## 5. Canadian Entitlement Return

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

The storage volume in Duncan is 1.4 maf, in Arrow 7.1 maf, and the whole of Canadian storage 15.5 maf. The obligation of the United States to deliver Canadian Entitlement to Canada for operating year 1998-99 beginning 1 August 1998 and ending 31 July 1999 is computed to be:

a) Energy Entitlement

For the period 1 August 1998 through 31 March 1999 (Duncan return)

Average Annual Energy = 562.7 aMW * (1.4 maf/15.5 maf) = 50.8 aMW

For the period 1 April 1999 through 31 July 1999 (Duncan and Arrow return)

Average Annual Energy = 562.7 aMW * (8.5 maf/15.5 maf) = 308.6 aMW

The average annual energy was computed from the joint optimum power studies.

b) Capacity Entitlement

For the period 1 August 1998 through 31 March 1999 (Duncan return)

Dependable Capacity
- Discretionary Draft for Power interpretation
  = 1324.7 MW * (1.4 maf/15.5 maf) = 119.7 MW
- Draft for Power interpretation
  = 1514.7 MW * (1.4 maf/15.5 maf) = 136.8 MW

For the period 1 April 1999 through 31 July 1999 (Duncan and Arrow return)

Dependable Capacity
- Discretionary Draft for Power interpretation
  = 1324.7 MW * (8.5 maf/15.5 maf) = 726.4 MW
- Draft for Power interpretation
  = 1514.7 MW * (8.5 maf/15.5 maf) = 830.6 MW

## 6. Summary of Canadian Entitlement Computations

The following Tables and Chart summarize the study results. Tables 1, 2, and 4 for the 1998-99 DDPB were reformatted to present study results more clearly.

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

This table shows the loads and resources used in the Step I studies and the computation of the residual hydro load for the Step I study. This table has been reorganized to more closely follow the definition of Step I loads and resources as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Table 1 was also split into tables 1A and 1B. Table 1A shows the Step I energy loads and resources while Table 1B shows the Step I peak loads and resources.

**Table 2.** Determination of Thermal Displacement Market:

This table shows the computation of the thermal displacement market for the downstream power benefit determination of average annual usable energy. The thermal displacement market was limited to the existing and scheduled thermal energy capability including thermal imports after allowance for energy reserves, minimum thermal generation, and reductions for the thermal resources used outside the PNW Area. The computation of Step I thermal installations has been moved to Table 1.

**Table 3.** Determination of Loads for 1998-99 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 joint BPA/Northwest Power Planning Council November 1992 load forecast. The Grand Coulee pumping load is also included in this estimate. The method for computing the firm load for the Step II and III studies is described in the 1988 Entity Agreements and in POP.

**Table 4.** Summary of Power Regulations from 1998-99 Assured Operating Plan:

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system. The determination of the Step I, II, and III loads and thermal installations is now shown in Tables 1 and 3. Table 4 was split into Tables 4A and 4B. Table 4A summarizes results of Step I and Step II power regulation studies. Table 4B summarizes the Step III power regulation study for both the Discretionary Draft for Power and the Draft for Power interpretations of critical stream flow period interpretations.

**Table 5.** Computation of Canadian Entitlement For 1998-99 Assured Operating Plan:

A. Optimum Generation in Canada and the U.S.
B. Optimum Generation in the U.S. Only
C. Optimum Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage

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

Chart 1. 1998-99 Determination of Downstream Power Benefits 30-Year Monthly Hydro Generation:

This chart shows duration curves of the hydro generation from the Step II and III studies and graphically illustrates the change in the portion of secondary energy that is usable for thermal displacement due to operation of Treaty storage. Secondary energy is the energy capability each month which exceeds the firm hydro loads shown in Table 3. The usable secondary energy in average megawatts for the Step II and III studies is computed in accordance with Annex B, Paragraphs 3(b) and 3(c), as the portion of secondary energy which can displace thermal resources used to meet PNW area loads plus the other usable secondary generation. The Entities have agreed that "the other usable secondary" is computed on the basis of 40 percent of the remainder after thermal displacement.

## 7. Summary of Changes From Previous Year

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

(a) Loads and Resources

Loads for the 1998-99 AOP were based on the joint BPA/Northwest Power Planning Council November 1992 load forecast. The Pacific Northwest Area firm energy load increased by 92.3 annual aMW. The total exports, not including firm surplus energy, increased by 149.0 aMW. The firm surplus energy increased by 101.4 aMW. The increase in exports is due to an additional export sale to the southwest and the increased Canadian Entitlement Return.

The estimated increase in PNW area load for return of the Canadian Entitlement and the computed Canadian Entitlement attributed to Duncan and Arrow for the period 1 August 1998 through 31 July 1999 is shown below for the joint optimum studies:

| | Energy Entitlement (aMW) | | Capacity Entitlement (MW) | | |
|---|---|---|---|---|---|
| | Estimated | Computed | Estimated | Computed 1/ A | Computed 1/ B |
| 1 August 1998 to 31 March 1999 | 50.0 | 50.8 | 111.0 | 119.7 | 136.8 |
| 1 April 1999 to 31 July 1999 | 302.0 | 308.6 | 675.0 | 726.4 | 830.6 |

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

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

The total energy capability of the thermal installations increased by 338.8 aMW. Major thermal resource changes included: 1) Removal of the Trojan Nuclear plant from the resource stack, 2) Combustion Turbine resource increases of 827.2 aMW due to new facilities acquired to replace the loss of the Trojan Nuclear plant; 3) Co-generation increases of 69.4 aMW due the addition of two new projects; and 4) Thermal Non-Utility Generation (NUGs) increases of 52.2 aMW.

(b) Operating Procedures

The 1990 level modified base flows were used, with no additional depletion to the 1999 level, based on the recommendation of the Columbia River Water Management Group. Coulee pumping adjustments and return flow, however, were included. The previous AOP/DDPB was based on the 1980 level modified base flows. Irrigation depletions were substantially less in the 1990 level modified flows, primarily in the Snake River basin above Brownlee.

The 1990 level modified flows resulted in increased flows in the Step I and Step II critical period studies due to the lower level of irrigation depletions. Updated streamflows reduced the Step III critical period generation due to lower return flows in the fall combined with a shortened critical period ending 15 April rather than 30 April in the 1997-98 AOP. Expected reductions in fish spill due to planned installation of fish bypass facilities at The Dalles and John Day by January 1998 resulted in increased Step I and II critical period generation at those projects.

Due to time constraints associated with completing the Entitlement Forecast Report, the Entities agreed not to complete refill studies for the 1998-99 Step I, II, and III studies. Power discharge requirements (PDRs) from the 1997-98 AOP/DDPB were used in the 1998-99 AOP/DDPB. A Step I refill test was performed, however, to verify that the 1997-98 PDRs provided results that were within acceptable limits.

The Entities agreed to implement the PNCA 6(c)(2)(c) provision which requires that in multiple year critical period studies no reservoir be drafted below its ARC by April 1, until all reservoirs have been drafted to their ARC's determined in PNCA 7(b)(2). This caused the greatest change in the Step I study because the ARC for Coulee at the end of March is empty and recent practice had been to ignore this PNCA provision in Step I but not Step II studies. The changed Coulee operation was the major contributor to a reduction in the Step I critical period generation of almost 50 MW.

Notable changes in non-power constraints include: Removal of the Inchelium Ferry minimum content constraint of 289.1 ksfd at Coulee by the Bureau of Reclamation; Implementation of new fisheries requirements at Dworshak which were reflected by beginning the Step I critical period 10 feet below full pool, drafting the reservoir empty only in the last few periods of the critical period, and essentially operating the reservoir on upper rule curve or minimum flow in the long-term study; and additional minimum and maximum outflow requirements at Kerr. Plant data for the lower Snake River projects (Lower Granite, Little Goose, Lower Monumental, and Ice Harbor) were revised to allow the projects to be operated as reservoirs although for this AOP they were operated in the traditional fashion as run-of-river projects. Because Dworshak was operated on a fixed operation, it was not included in the Step I refill test.

(c) Step III Critical Stream Flow Period

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

Under the Discretionary Draft for Power interpretation, the Step III study had a critical stream flow period of 5.5 months, 1 November 1936 through 15 April 1937 . Under the Draft for Power interpretation, the Step III study had a critical stream flow period of 6 months, 1 October 1936 through 15 April 1937. The Step III critical stream flow period in the previous AOP was 6 months, 1 November 1936 through 30 April 1937. The end of the Step III critical stream flow period changed because of a reduction in residual hydro load in the second half of April resulting from the removal of Trojan from the resource stack (with maintenance in the second half of April) and its replacement primarily by combustion turbines (with maintenance spread throughout the year).

(d) Downstream Power Benefits Computation

Under the Discretionary Draft for Power interpretation, the Capacity Entitlement increased from 1229.6 MW in the 1997-98 DDPB to 1324.7 MW in the 1998-99 DDPB for a gain of 95.1 MW. The primary reason for the capacity entitlement increase is the 108.2 MW decrease in the Step III critical period average generation which in turn resulted from the second half of April not being included in the 1998-99 Step III critical stream flow period. The Step II average critical period generation increased by 46.1 MW compared to the 1997-98 DDPB due to updated stream flows. Therefore, the difference between the Step II and Step III average critical period generation increased resulting in an increase in the Capacity Entitlement.

Under the Draft for Power interpretation, the Capacity Entitlement increased to 1514.7 MW in the 1998-99 DDPB for a gain of 285.1 MW. Relative to the Capacity Entitlement under the Discretionary Draft for Power interpretation, the Capacity Entitlement under the Draft for Power interpretation increased by 190 MW because the start of the Step III critical stream flow period changed from November to October which caused the average rate of generation during the Step III critical stream flow period to decrease by 287.3 MW.

The Canadian Energy Entitlement increased from 553.3 aMW in the 1997-98 DDPB to 562.7 aMW in the 1998-99 DDPB, an increase of 9.4 aMW. New data including the 1990 level modified flows and fish bypass systems increased the Energy Entitlement while a larger thermal displacement market decreased the Energy Entitlement. The net effect of all changes was the small increase in the Energy Entitlement.

# TABLE 1A
## 1998-99 ASSURED OPERATING PLAN
## DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES 1/

| | | Aug15 | Aug31 | Sept | Oct | Nov | Dec | Jan | Feb | March | Apr15 | Apr30 | May | June | July | Annual Average | CP Ave 3/ (42 Mon) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Step I Energy Loads (aMW)** | | | | | | | | | | | | | | | | | |
| 1. | PNW Area Load | 19065 | 18987 | 18385 | 19153 | 21235 | 22806 | 23722 | 22499 | 21202 | 20014 | 20112 | 19322 | 19180 | 19260 | 20479.6 | 20597.0 |
| 2. | Annual Load Shape (Percent) | 93.09 | 92.71 | 89.77 | 93.52 | 103.69 | 111.36 | 115.83 | 109.86 | 103.53 | 97.73 | 98.21 | 94.35 | 93.65 | 94.04 | 100.0 | 100.6 |
| 3. | Firm Exports | 1261 | 1261 | 1278 | 946 | 879 | 888 | 863 | 835 | 887 | 1131 | 1131 | 1068 | 1380 | 1476 | 1075.3 | 1057.1 |
| 4. | Minus Plant Sales | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -40 | -71 | -102 | -94.2 | -95.3 |
| 5. | Firm Surplus | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3199 | 3199 | 0 | 534.6 | 458.4 |
| 6. | Hydro Maintenance | 32 | 27 | 9 | 9 | 4 | 0 | 0 | 0 | 5 | 7 | 8 | 20 | 16 | 51 | 12.7 | 11.4 |
| | Load Reduction Resources | | | | | | | | | | | | | | | | |
| 7. | Hydro Independents (1929) | -1205 | -1147 | -1015 | -1078 | -1104 | -1004 | -1033 | -760 | -891 | -1211 | -1270 | -1731 | -1537 | -1222 | -1151.6 | -1009.5 |
| 8. | Other Coord Hydro (1929) | -547 | -474 | -600 | -986 | -990 | -989 | -1087 | -728 | -891 | -602 | -665 | -702 | -1140 | -817 | -840.3 | -877.1 |
| 9. | Non-Thermal Purpa/Nugs | -189 | -189 | -183 | -171 | -171 | -168 | -170 | -177 | -184 | -201 | -201 | -211 | -219 | -203 | -187.1 | -185.1 |
| 10. | Miscellaneous | -20 | -20 | -20 | -20 | -20 | -20 | -20 | -20 | -20 | -17 | -17 | -17 | -17 | -20 | -19.3 | -19.4 |
| 11. | Non-thermal firm imports | -20 | -20 | -15 | -21 | -37 | -47 | -60 | -69 | -62 | -29 | -29 | -28 | -38 | -26 | -37.5 | -38.0 |
| 12. | Seasonal Exchange Imports | 0 | 0 | 0 | 0 | -323 | -359 | -351 | -348 | -51 | -6 | -6 | 0 | 0 | 0 | -118.4 | -134.2 |
| 13. | Total Step I Study Loads (1929) | 18275 | 18323 | 17737 | 17730 | 19371 | 21005 | 21762 | 21130 | 19893 | 18984 | 18961 | 20880 | 20753 | 18397 | 19653.9 | 19765.3 |
| **Step I Thermal Resources (aMW)** | | | | | | | | | | | | | | | | | |
| 14. | Large Thermal | 4588 | 4588 | 4588 | 4588 | 4588 | 4588 | 4588 | 4588 | 4401 | 4054 | 3337 | 2408 | 3674 | 4588 | 4238.5 | 4288.3 |
| 15. | Small Thermal | 130 | 130 | 130 | 130 | 136 | 136 | 136 | 136 | 130 | 130 | 130 | 130 | 130 | 130 | 132.0 | 132.3 |
| 16. | Combustion Turbines | 1831 | 1702 | 1735 | 1946 | 1909 | 1958 | 1958 | 1958 | 1786 | 1536 | 1596 | 1592 | 1189 | 1618 | 1748.2 | 1771.4 |
| 17. | Cogeneration | 761 | 761 | 775 | 776 | 778 | 778 | 778 | 778 | 777 | 765 | 765 | 365 | 683 | 761 | 730.7 | 737.3 |
| 18. | Purpa/Nugs - Thermal | 283 | 283 | 274 | 256 | 257 | 252 | 255 | 265 | 276 | 302 | 302 | 316 | 328 | 304 | 280.7 | 277.7 |
| 19. | Renewables | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49 | 49.0 | 49.0 |
| 20. | Thermal Firm Imports | 1199 | 1183 | 931 | 1110 | 1764 | 1907 | 1898 | 1896 | 1524 | 1187 | 1130 | 1061 | 1249 | 1272 | 1411.0 | 1435.6 |
| 21. | Minus Seas Exch Imports | 0 | 0 | 0 | 0 | -323 | -359 | -351 | -348 | -51 | -6 | -6 | 0 | 0 | 0 | -118.4 | -134.2 |
| 22. | Minus Plant Sales | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -40 | -71 | -102 | -94.2 | -95.3 |
| 23. | Total Step I Thermal Installations | 8739 | 8594 | 8380 | 8753 | 9056 | 9207 | 9209 | 9220 | 8790 | 7915 | 7201 | 5881 | 7231 | 8620 | 8377.4 | 8462.0 |
| **Regulated Hydro Load (1929) 2/** | | 9536 | 9729 | 9357 | 8977 | 10315 | 11798 | 12553 | 11910 | 11103 | 11069 | 11760 | 14999 | 13522 | 9777 | 11276.5 | 11303.3 |

Notes:

1/ Step I Loads and Resources for the U.S. Optimum Study (99-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements.

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

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

# TABLE 1B
## 1998-99 ASSURED OPERATING PLAN
## DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES 1/

| | | Aug15 | Aug31 | Sept | Oct | Nov | Dec | Jan | Feb | March | Apr15 | Apr30 | May | June | July |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Step I Peak Loads (MW)** | | | | | | | | | | | | | | | |
| 1. | PNW Area Load | 23608 | 23563 | 23337 | 26123 | 28568 | 30749 | 32195 | 31018 | 28786 | 27251 | 27333 | 25584 | 24238 | 24050 |
| 2. | Load Factor (Percent) | 80.59 | 80.59 | 78.78 | 73.32 | 74.33 | 74.17 | 73.68 | 72.54 | 73.65 | 73.41 | 73.41 | 75.52 | 79.13 | 80.08 |
| 3. | Firm Exports | 2496 | 2496 | 2509 | 1976 | 1227 | 1203 | 1204 | 1204 | 1202 | 1764 | 1764 | 1883 | 2965 | 2987 |
| 4. | Minus Plant Sales | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -45 | -116 | -116 |
| 5. | Firm Surplus | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4236 | 4042 | 0 |
| 6. | Hydro Maintenance | 4629 | 4066 | 3787 | 3208 | 2935 | 2037 | 1561 | 2295 | 2646 | 2751 | 2483 | 2360 | 2204 | 3725 |
| | Load Reduction Resources | | | | | | | | | | | | | | |
| 7. | Hydro Independents (1937) | -1875 | -1858 | -1785 | -1735 | -1681 | -1659 | -1599 | -1706 | -1787 | -1910 | -1936 | -2107 | -2134 | -1970 |
| 8. | Other Coord Hydro (1937) | -2673 | -2578 | -2669 | -2608 | -2504 | -2428 | -2204 | -2034 | -1974 | -2094 | -2112 | -2237 | -2451 | -2646 |
| 9. | Non-Thermal Purpa/Nugs | -205 | -205 | -198 | -185 | -184 | -181 | -185 | -191 | -200 | -215 | -215 | -225 | -233 | -217 |
| 10. | Miscellaneous | 0 | 0 | 0 | 0 | -300 | -300 | -300 | -300 | -300 | 0 | 0 | 0 | 0 | 0 |
| 11. | Non-thermal firm imports | -147 | -147 | -147 | -147 | -134 | -148 | -170 | -194 | -224 | -147 | -147 | -147 | -147 | -147 |
| 12. | Minus Seasonal Exchange | 0 | 0 | 0 | 0 | -675 | -721 | -721 | -721 | -196 | -12 | -12 | 0 | 0 | 0 |
| 13. | Total Step I Study Loads (1937) | 25717 | 25221 | 24718 | 26516 | 27136 | 28436 | 29665 | 29255 | 27837 | 27272 | 27042 | 29302 | 28388 | 25666 |
| **Step I Thermal Resources (MW)** | | | | | | | | | | | | | | | |
| 14. | Large Thermal | 5253 | 5253 | 5253 | 5253 | 5253 | 5253 | 5253 | 5253 | 4988 | 4776 | 3780 | 2511 | 4237 | 5253 |
| 15. | Small Thermal | 146 | 146 | 146 | 146 | 235 | 235 | 235 | 235 | 146 | 146 | 146 | 146 | 146 | 146 |
| 16. | Combustion Turbines | 2552 | 2374 | 2483 | 2769 | 2741 | 2741 | 2769 | 2769 | 2344 | 2302 | 2263 | 2271 | 2082 | 2530 |
| 17. | Cogeneration | 817 | 817 | 818 | 820 | 822 | 822 | 822 | 822 | 821 | 821 | 821 | 275 | 658 | 817 |
| 18. | Purpa/Nugs - Thermal | 307 | 307 | 297 | 277 | 276 | 271 | 278 | 287 | 300 | 322 | 322 | 337 | 350 | 326 |
| 19. | Renewables | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| 20. | Thermal Firm Imports | 1537 | 1533 | 1129 | 1374 | 2425 | 2447 | 2432 | 2333 | 1796 | 1306 | 1286 | 1651 | 1662 | 1556 |
| 21. | Minus Seas Exch Imports | 0 | 0 | 0 | 0 | -675 | -721 | -721 | -721 | -196 | -12 | -12 | 0 | 0 | 0 |
| 22. | Minus Plant Sales | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -116 | -45 | -116 | -116 |
| 23. | Total Step I Thermal Installations | 10547 | 10365 | 10061 | 10574 | 11012 | 10983 | 11003 | 10913 | 10134 | 9596 | 8541 | 7197 | 9070 | 10563 |
| **Regulated Hydro Load (1937) 2/** | | 15170 | 14856 | 14657 | 15942 | 16124 | 17453 | 18662 | 18342 | 17703 | 17676 | 18501 | 22105 | 19318 | 15103 |

Notes:

1/ Step I Loads and Resources for the U.S. Optimum study (99-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements.

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

## TABLE 2

### 1998-99 ASSURED OPERATING PLAN
### DETERMINATION OF THERMAL DISPLACEMENT MARKET
(Energy in Average MW)

| | Aug15 | Aug31 | Sept | Oct | Nov | Dec | Jan | Feb | March | Apr15 | Apr30 | May | June | July | Annual Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **TOTAL STEP I THERMAL INSTALLATIONS** | | | | | | | | | | | | | | | |
| 1. From Table 1A, line 23 | 8739 | 8594 | 8380 | 8753 | 9056 | 9207 | 9209 | 9220 | 8790 | 7915 | 7201 | 5881 | 7231 | 8620 | 8377.4 |
| **SYSTEM SALES** | | | | | | | | | | | | | | | |
| 2. Total Exports | 1261 | 1261 | 1278 | 946 | 879 | 888 | 863 | 835 | 887 | 1131 | 1131 | 1068 | 1380 | 1476 | 1075.3 |
| 3. Minus Can Entitlement (out of the PNWA) | -50 | -50 | -50 | -50 | -50 | -50 | -50 | -50 | -50 | -302 | -302 | -302 | -302 | -302 | -134.2 |
| 4. Minus Plant Sales Exports | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -102 | -40 | -71 | -102 | -94.2 |
| 5. Minus Seasonal Exch. Exports | -342 | -342 | -351 | -37 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -312 | -353 | -116.7 |
| 6. Added Firm Surplus Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3199 | 3199 | 0 | 534.6 |
| 7. Total System Sales | 767 | 767 | 775 | 757 | 727 | 736 | 711 | 683 | 735 | 727 | 727 | 3925 | 3894 | 719 | 1264.8 |
| 8. Uniform Avg. Annual System Sales | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1265 | 1264.8 |
| **MINIMUM THERMAL GENERATION** | | | | | | | | | | | | | | | |
| 9. Large Thermal Min. Generation | 374 | 374 | 683 | 683 | 683 | 683 | 683 | 683 | 594 | 264 | 258 | 282 | 374 | 374 | 528.8 |
| 10. Cogen & Small Thermal Min. Generation | 145 | 145 | 146 | 146 | 147 | 147 | 147 | 147 | 146 | 146 | 146 | 146 | 145 | 145 | 146.1 |
| 11. NUGS Thermal Min. Generation | 93 | 93 | 90 | 84 | 85 | 83 | 84 | 87 | 91 | 100 | 100 | 104 | 108 | 100 | 92.4 |
| 12. Total Minimum Generation | 612 | 612 | 919 | 913 | 915 | 913 | 914 | 917 | 831 | 510 | 504 | 532 | 627 | 619 | 767.3 |
| **13. THERMAL DISPLACEMENT MARKET** | 6862 | 6717 | 6196 | 6575 | 6876 | 7029 | 7030 | 7038 | 6694 | 6140 | 5432 | 4084 | 5339 | 6736 | 6345.3 |

Notes:

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

# TABLE 3
## 1998-99 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 | 19065 | 93.09 | 23608 | 80.59 | 8739 | 16176.5 | 7437.5 | 13851.4 | 5112.4 | | Aug. 1-15 |
| Aug. 16-31 | 18987 | 92.71 | 23563 | 80.59 | 8594 | 16110.3 | 7516.3 | 13794.8 | 5200.8 | | Aug. 16-31 |
| September | 18385 | 89.77 | 23337 | 78.78 | 8380 | 15599.5 | 7219.5 | 13357.4 | 4977.4 | | September |
| October | 19153 | 93.52 | 26123 | 73.32 | 8753 | 16251.2 | 7498.2 | 13915.4 | 5162.4 | | October |
| November | 21235 | 103.69 | 28568 | 74.33 | 9056 | 18017.7 | 8961.7 | 15428.0 | 6372.0 | | November |
| December | 22806 | 111.36 | 30749 | 74.17 | 9207 | 19350.7 | 10143.7 | 16569.4 | 7362.4 | | December |
| January | 23722 | 115.83 | 32195 | 73.68 | 9209 | 20127.9 | 10918.9 | 17234.9 | 8025.9 | | January |
| February | 22499 | 109.86 | 31018 | 72.54 | 9220 | 19090.2 | 9870.2 | 16346.4 | 7126.4 | | February |
| March | 21202 | 103.53 | 28786 | 73.65 | 8790 | 17989.7 | 9199.7 | 15404.0 | 6614.0 | | March |
| April 1-15 | 20014 | 97.73 | 27251 | 73.41 | 7915 | 16981.7 | 9066.7 | 14540.9 | 6625.9 | | April 1-15 |
| April 16-30 | 20112 | 98.21 | 27333 | 73.41 | 7201 | 17064.9 | 9863.9 | 14612.1 | 7411.1 | | April 16-30 |
| May | 19322 | 94.35 | 25584 | 75.52 | 5881 | 16394.5 | 10513.5 | 14038.1 | 8157.1 | | May |
| June | 19180 | 93.65 | 24238 | 79.13 | 7231 | 16274.1 | 9043.1 | 13935.0 | 6704.0 | | June |
| July | 19260 | 94.04 | 24050 | 80.08 | 8620 | 16341.9 | 7721.9 | 13993.1 | 5373.1 | | July |
| Annual Average = | 20479.6 | 100.00 | | 75.78 | 8378.0 | 17376.7 | 8999.9 | 14879.2 | 6502.1 | | Annual Avg |
| Critical Period Avg (42) = | 20597.0 | | | 75.60 | 8462.0 | 17599.7 | 9064.1 | | | | |
| Step II Crit. Per. Avg (20) = | 20742.4 | | | | 8535.7 | | | | | | |
| Step III Crit. Per. Avg: | | | | | | | | | | | |
| Discretionary Draft Method (5.5) | 22089.5 | | | | 8987.7 | | | 16048.9 | 7061.2 | | Crit.Per.Avg |
| Draft for Power Method (6.5) | 21627.4 | | | | 8950.7 | | | 15713.1 | 6762.4 | | Crit.Per.Avg |
| | | | | | | Input 5/= | **9064.1** | Input 6/= | | | |
| | | | | | | | | Discretionary Draft | | **7061.2** | |
| | | | | | | | | Draft for Power | | **6762.4** | |
| August 1-31 | 19024.7 | 92.9 | 23608.0 | 80.59 | 8664.2 | 16142.3 | 7478.2 | 13822.2 | 5158.0 | | Aug. 1-31 |
| April 1-30 | 20063.0 | 98.0 | 27333.0 | 73.41 | 7558.0 | 17023.3 | 9465.3 | 14576.5 | 7018.5 | | Apr. 1-30 |

1/ The PNW Area load does not include the exports, but does include pumping. The computation of the load shape for Step II/III studies used these loads.
2/ The thermal installations include all thermal used to meet the Step I system load. (Table 1A, line 23).
3/ The total firm load for the Step II/III studies is computed to have the same shape as the load of the PNW Area.
4/ The hydro load is equal to the total load minus the Step I study thermal installations.
5/ Input is the assumed critical period average generation for the Step II hydro studies and is used to calculate the residual hydro loads.
6/ Discretionary Draft input = 7061.2 MW, Draft for Power input = 6762.4 MW.
The Draft for Power Step III critical period method excludes 74.6 (aMW) of October surplus (critical period average = 11.7 MW) which cannot be shaped to meet the firm load.

TABLE 4A
SUMMARY OF POWER REGULATIONS FOR STEP I & II
FROM 1998-99 ASSURED OPERATING PLAN

| PROJECTS | BASIC DATA: NUMBER OF UNITS | BASIC DATA: NOMINAL INSTALLED PEAKING CAPACITY MW | STEP I: USABLE STORAGE 1000 AF | STEP I: JANUARY 1937 PEAKING CAP. MW | STEP I: CRITICAL PERIOD AVERAGE GEN. MW | STEP II: USABLE STORAGE 1000 AF | STEP II: JANUARY 1945 PEAKING CAP. MW | STEP II: CRITICAL PERIOD AVERAGE GEN. MW | STEP II: 30 YEAR AVERAGE ANNUAL GEN. MW |
|---|---|---|---|---|---|---|---|---|---|
| **HYDRO RESOURCES** | | | | | | | | | |
| **CANADIAN** | | | | | | | | | |
| Mica | | | 7000 | | | 7000 | | | |
| Arrow | | | 7100 | | | 7100 | | | |
| Duncan | | | 1400 | | | 1400 | | | |
| Subtotal | | | 15500 | | | 15500 | | | |
| **BASE SYSTEM** | | | | | | | | | |
| Hungry Horse | 4 | 428 | 3072 | 329 | 101 | 3008 | 203 | 116 | 106 |
| Kerr | 3 | 160 | 1219 | 155 | 120 | 1219 | 153 | 111 | 122 |
| Thompson Falls | 6 | 40 | 0 | 40 | 38 | 0 | 40 | 39 | 37 |
| Noxon Rapids | 5 | 554 | 231 | 519 | 151 | 0 | 554 | 134 | 201 |
| Cabinet Gorge | 4 | 230 | 0 | 230 | 100 | 0 | 230 | 88 | 117 |
| Albeni Falls | 3 | 49 | 1155 | 22 | 25 | 1155 | 20 | 23 | 22 |
| Box Canyon | 4 | 74 | 0 | 72 | 46 | 0 | 70 | 45 | 48 |
| Grand Coulee | 24+3SS | 6684 | 5185 | 6004 | 1941 | 5072 | 6380 | 1785 | 2311 |
| Chief Joseph | 27 | 2614 | 0 | 2586 | 1107 | 0 | 2586 | 1007 | 1353 |
| Wells | 10 | 840 | 0 | 840 | 415 | 0 | 840 | 386 | 482 |
| Chelan | 2 | 54 | 677 | 51 | 39 | 676 | 51 | 38 | 44 |
| Rocky Reach | 11 | 1267 | 0 | 1267 | 576 | 0 | 1267 | 534 | 694 |
| Rock Island | 18 | 544 | 0 | 544 | 280 | 0 | 544 | 261 | 330 |
| Wanapum | 10 | 986 | 0 | 986 | 518 | 0 | 986 | 482 | 603 |
| Priest Rapids | 10 | 912 | 0 | 912 | 497 | 0 | 912 | 470 | 565 |
| Brownlee | 5 | 675 | 975 | 675 | 241 | 974 | 675 | 313 | 316 |
| Oxbow | 4 | 220 | 0 | 220 | 99 | 0 | 220 | 124 | 128 |
| Ice Harbor | 6 | 693 | 0 | 693 | 224 | 0 | 693 | 239 | 310 |
| McNary | 14 | 1127 | 0 | 1127 | 653 | 0 | 1127 | 637 | 803 |
| John Day | 16 | 2484 | 535 | 2484 | 955 | 0 | 2484 | 921 | 1255 |
| The Dalles | 22+2F | 2074 | 0 | 2074 | 755 | 0 | 2074 | 733 | 995 |
| Bonneville | 18+2F | 1147 | 0 | 1147 | 596 | 0 | 1147 | 579 | 730 |
| Kootenay Lake | 0 | 0 | 673 | 0 | 0 | 673 | 0 | 0 | 0 |
| Coeur d'Alene Lake | 0 | 0 | 223 | 0 | 0 | 223 | 0 | 0 | 0 |
| Total Base System Hydro | | 23856 | 29446 | 22977 | 9478 | 28500 | 23256 | 9064 | 11572 |
| **ADDITIONAL STEP I PROJECTS** | | | | | | | | | |
| Libby | 5 | 600 | 4980 | 561 | 198 | NOT APPLICABLE TO STEP II | | | |
| Boundary | 6 | 1055 | 0 | 855 | 369 | | | | |
| Spokane River Plants | 24 | 156 | 104 | 159 | 99 | | | | |
| Hells Canyon | 3 | 450 | 0 | 410 | 193 | | | | |
| Dworshak | 3 | 450 | 2015 | 447 | 173 | | | | |
| Lower Granite | 6 | 932 | 0 | 928 | 222 | | | | |
| Little Goose | 6 | 932 | 0 | 928 | 219 | | | | |
| Lower Monumental | 6 | 932 | 0 | 922 | 223 | | | | |
| Pelton, Rereg., & RB | 7 | 423 | 274 | 417 | 127 | | | | |
| Subtotal | | 5930 | 7373 | 5627 | 1822 | | | | |
| **THERMAL INSTALLATION 1/** | | | | 11003 | 8462 | | 11003 | 8536 | |
| **RESERVES 2/** | | | | -2576 | 0 | | -2185 | 0 | |
| **TOTAL RESOURCES** | | | | 37031 | 19762 | | 32074 | 17600 | |
| **STEP I, II, & III LOADS 3/** | | | | 29665 | 19765 | | 27317 | 17600 | |
| **SURPLUS** | | | | 7366 | -3 | | 4757 | 0 | |
| **CRITICAL PERIOD** | Starts | | September 1, 1928 | | | September 1, 1943 | | | |
| | Ends | | February 29, 1932 | | | April 30, 1945 | | | |
| | Length (Months) | | 42 Months | | | 20 Months | | | |
| | Study Identification | | 99-41 | | | 99-42 | | | |

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

**TABLE 4B**
**SUMMARY OF POWER REGULATIONS FOR STEP III**
**FROM 1998-99 ASSURED OPERATING PLAN**

| PROJECTS | BASIC DATA | | STEP III 4/ | | | | |
|---|---|---|---|---|---|---|---|
| | NUMBER OF UNITS | NOMINAL INSTALLED PEAKING CAPACITY MW | USABLE STORAGE 1000 AF | JANUARY 1937 PEAKING CAP. MW | CRITICAL PERIOD AVERAGE GENERATION: DISCRETIONARY DRAFT FOR POWER MW | CRITICAL PERIOD AVERAGE GENERATION: DRAFT FOR POWER MW | 30 YEAR AVERAGE ANNUAL GEN. MW |
| **HYDRO RESOURCES** | | | | | | | |
| **CANADIAN** | | | | | | | |
| Mica | | | | | | | |
| Arrow | | | | | | | |
| Duncan | | | | | | | |
| Subtotal | | | | | | | |
| **BASE SYSTEM** | | | | | | | |
| Hungry Horse | 4 | 428 | 3008 | 338 | 187 | 172 | 103 |
| Kerr | 3 | 160 | 1219 | 151 | 145 | 131 | 122 |
| Thompson Falls | 6 | 40 | 0 | 40 | 39 | 37 | 36 |
| Noxon Rapids | 5 | 554 | 0 | 554 | 175 | 157 | 202 |
| Cabinet Gorge | 4 | 230 | 0 | 230 | 110 | 99 | 118 |
| Albeni Falls | 3 | 49 | 1155 | 18 | 18 | 19 | 22 |
| Box Canyon | 4 | 74 | 0 | 70 | 55 | 52 | 47 |
| Grand Coulee | 24+3SS | 6684 | 5072 | 5655 | 1207 | 1181 | 2256 |
| Chief Joseph | 27 | 2614 | 0 | 2586 | 733 | 705 | 1278 |
| Wells | 10 | 840 | 0 | 840 | 290 | 280 | 441 |
| Chelan | 2 | 54 | 676 | 51 | 51 | 45 | 42 |
| Rocky Reach | 11 | 1267 | 0 | 1267 | 391 | 374 | 650 |
| Rock Island | 18 | 544 | 0 | 544 | 188 | 180 | 301 |
| Wanapum | 10 | 986 | 0 | 986 | 343 | 329 | 545 |
| Priest Rapids | 10 | 912 | 0 | 912 | 349 | 336 | 506 |
| Brownlee | 5 | 675 | 974 | 675 | 284 | 278 | 315 |
| Oxbow | 4 | 220 | 0 | 220 | 121 | 117 | 128 |
| Ice Harbor | 6 | 693 | 0 | 693 | 174 | 167 | 310 |
| McNary | 14 | 1127 | 0 | 1127 | 488 | 466 | 750 |
| John Day | 16 | 2484 | 0 | 2484 | 693 | 665 | 1220 |
| The Dalles | 22+2F | 2074 | 0 | 2074 | 569 | 552 | 974 |
| Bonneville | 18+2F | 1147 | 0 | 1147 | 451 | 433 | 694 |
| Kootenay Lake | 0 | 0 | 673 | 0 | 0 | 0 | 0 |
| Coeur d'Alene Lake | 0 | 0 | 223 | 0 | 0 | 0 | 0 |
| Total Base System Hydro | | 23856 | 13000 | 22662 | 7061 | 6774 | 11060 |
| **ADDITIONAL STEP I PROJECTS** | | | | | | | |
| Libby | 5 | 600 | NOT APPLICABLE TO STEP III | | | | |
| Boundary | 6 | 1055 | | | | | |
| Spokane River Plants | 24 | 156 | | | | | |
| Hells Canyon | 3 | 450 | | | | | |
| Dworshak | 3 | 450 | | | | | |
| Lower Granite | 6 | 932 | | | | | |
| Little Goose | 6 | 932 | | | | | |
| Lower Monumental | 6 | 932 | | | | | |
| Pelton, Rereg., & RB | 7 | 423 | | | | | |
| Subtotal | | 5930 | | | | | |
| **THERMAL INSTALLATION 1/** | | | | 11003 | 8988 | 8951 | |
| **RESERVES 2/** | | | | -1871 | 0 | 0 | |
| **TOTAL RESOURCES** | | | | 31794 | 16049 | 15725 | |
| **STEP I, II, & III LOADS 3/** | | | | 23391 | 16049 | 15713 | |
| **SURPLUS** | | | | 8403 | 0 | 12 | |
| **CRITICAL PERIOD** | Starts | | | | November 1, 1936 | October 1, 1936 | |
| | Ends | | | | April 15, 1937 | April 15, 1937 | |
| | Length (Months) | | | | 5.5 Months | 6.5 Months | |
| | Study Identification | | | | 99-13 | 99-13 | |

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

TABLE 5

## COMPUTATION OF CANADIAN ENTITLEMENT FOR 1998-99 ASSURED OPERATING PLAN

A. Optimum Power Generation in Canada and the U.S. (From 99-42)
B. Optimum Power Generation in the U.S. Only (From 99-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 99-22)

**Determination of Dependable Capacity Credited to Canadian Storage - MW**

| | CAPACITY ENTITLEMENT | | | | | |
|---|---|---|---|---|---|---|
| | Discretionary Draft Interpretation | | | Draft for Power Interpretation | | |
| | (A) | (B) | (C) | (A) | (B) | (C) |
| Step II - Critical Period Avg. Generation 1/ | 9064.1 | 9064.7 | 9026.3 | 9064.1 | 9064.7 | 9026.3 |
| Step III - Critical Period Avg. Generation 2/ | 7061.2 | 7061.2 | 7061.2 | 6773.9 | 6773.9 | 6773.9 |
| Gain Due to Canadian Storage | 2002.9 | 2003.5 | 1965.1 | 2290.2 | 2290.8 | 2252.4 |
| Average Critical Period Load Factor in % 3/ | 75.60 | 75.60 | 75.60 | 75.60 | 75.60 | 75.60 |
| Dependable Capacity Gain 4/ | 2649.4 | 2650.2 | 2599.4 | 3029.4 | 3030.3 | 2979.5 |
| Canadian Share of Dependable Capacity 5/ | 1324.7 | 1325.1 | 1299.7 | 1514.7 | 1515.1 | 1489.7 |

**Determination of Increase in Average Annual Usable Energy - Average MW**

| | ENERGY ENTITLEMENT | | |
|---|---|---|---|
| Step II (with Canadian Storage) 1/ | (A) | (B) | (C) |
| Annual Firm Hydro Energy 6/ | 9000.0 | 9000.5 | 8962.6 |
| Thermal Replacement Energy 7/ | 2101.3 | 2111.1 | 2125.1 |
| Other Usable Secondary Energy 8/ | 188.3 | 186.2 | 190.4 |
| System Annual Average Usable Energy | 11289.6 | 11297.8 | 11278.1 |
| Step III (without Canadian Storage) 2/ | | | |
| Annual Firm Hydro Energy 6/ | 6502.1 | 6502.1 | 6502.1 |
| Thermal Replacement Energy 7/ | 3066.8 | 3066.8 | 3066.8 |
| Other Usable Secondary Energy 8/ | 595.3 | 595.3 | 595.3 |
| System Annual Average Usable Energy | 10164.2 | 10164.2 | 10164.2 |
| Average Annual Usable Energy Gain 9/ | 1125.4 | 1133.6 | 1113.9 |
| Canadian Share of Avg. Annual Energy Gain 5/ | 562.7 | 566.8 | 557.0 |

1/ Step II values were obtained from the 99-42, 99-12, and 99-22 studies, respectively.
2/ Step III values were obtained from the 99-13 study. The Draft for Power interpretation includes 74.6 aMW of surplus in October critical period average = 11.7 aMW) which cannot be shaped to meet the firm loads.
3/ Critical period load factor from Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ One-half of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load served.
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

| | 1993-94 | 1994-95 | 1995-96 | 1996-97 | 1997-98 | 1998-99 |
|---|---|---|---|---|---|---|
| **MICA TARGET OPERATION (ksfd or cfs)** | | | | | | |
| - AUG 1 | 3456.2 | 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 | 10000.0 | 3428.4 | 3428.4 | 14000.0 | 15000.0 | 11000.0 |
| - NOV | 19000.0 | 22000.0 | 22000.0 | 19000.0 | 19000.0 | 3256.2 |
| - DEC | 22000.0 | 24000.0 | 24000.0 | 23000.0 | 23000.0 | 2676.2 |
| - JAN | 26000.0 | 27000.0 | 27000.0 | 24000.0 | 24000.0 | 24000.0 |
| - FEB | 25000.0 | 25000.0 | 25000.0 | 20000.0 | 22000.0 | 22000.0 |
| - MAR | 22000.0 | 25000.0 | 25000.0 | 19000.0 | 19000.0 | 22000.0 |
| - APR 1 | 25000.0 | 24000.0 | 24000.0 | 156.2 | 106.2 | 86.2 |
| - APR 2 | 18000.0 | 14000.0 | 14000.0 | 0.0 | 0.0 | 56.2 |
| - MAY | 10000.0 | 10000.0 | 10000.0 | 10000.0 | 10000.0 | 10000.0 |
| - JUN | 10000.0 | 10000.0 | 10000.0 | 10000.0 | 10000.0 | 10000.0 |
| - JUL | 3256.2 | 3356.2 | 3356.2 | 3356.2 | 3356.2 | 3406.2 |
| **CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)** | | | | | | |
| NOV 1928 (-41) | 761.6 | 1272.6 | 1272.7 | 1481.7 | 922.2 | 638.8 |
| APR 1929 (-41) | 7754.1 | 7801.6 | 7801.6 | 7708.8 | 7727.7 | 7083.9 |
| JUL 1929 (-41) | 1139.5 | 1140.5 | 1140.5 | 1028.6 | 951.2 | 808.8 |
| AUG 1929 (-41) | 983.4 | 1060.4 | 1060.4 | 483.2 | 864.3 | 181.0 |
| NOV 1928 (-11) | 501.7 | 1275.3 | 1275.3 | 1483.6 | 923.3 | 642.0 |
| JUL 1929 (-11) | 1143.0 | 1142.8 | 1142.8 | 1036.6 | 955.2 | 830.8 |
| **STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)** | | | | | | |
| - U.S. Firm Energy | -1.4 | -4.4 | -4.4 | -2.0 | -0.9 | -5.1 |
| - U.S. Dependable Capacity | 3.0 | 2.0 | 2.0 | 3.0 | -4.0 | 27.0 |
| - U.S. Secondary Energy | -8.1 | 2.9 | 2.9 | 1.2 | 13.9 | 18.9 |
| - BCH Firm Energy | 40.1 | 56.0 | 56.0 | 36.0 | 46.7 | 26.7 |
| - BCH Dependable Capacity | -14.0 | 16.0 | 16.0 | -10.0 | 19.0 | 18.0 |
| - BCH Secondary Energy | -27.0 | -38.3 | -38.3 | -36.9 | -43.5 | -18.5 |
| **HYDROREG SECONDARY LOAD (MW)** | | | | | | |
| - AUG 1 | 10655 | 11475 | 11475 | 14510 | 14547 | 15568 |
| - AUG 2 | 10655 | 11475 | 11475 | 14396 | 14416 | 15422 |
| - SEP | 10092 | 11466 | 11466 | 14147 | 13878 | 14883 |
| - OCT | 10237 | 12021 | 12021 | 14616 | 14674 | 15594 |
| - NOV | 10083 | 12272 | 12272 | 15412 | 15411 | 16347 |
| - DEC | 10074 | 12443 | 12443 | 15951 | 15835 | 16578 |
| - JAN | 10914 | 12633 | 12633 | 16000 | 15832 | 16598 |
| - FEB | 10765 | 12641 | 12641 | 15884 | 15841 | 16638 |
| - MAR | 10405 | 11909 | 11909 | 15031 | 15160 | 15942 |
| - APR 1 | 10235 | 11817 | 11817 | 13840 | 14438 | 15523 |
| - APR 2 | 10933 | 11573 | 11573 | 13267 | 14391 | 15513 |
| - MAY | 7114 | 8114 | 8114 | 10734 | 10297 | 10960 |
| - JUN | 10079 | 11236 | 11236 | 14260 | 11748 | 11120 |
| - JUL | 10740 | 11590 | 11590 | 14648 | 14843 | 15529 |

TABLE 7

COMPARISON OF RECENT DDPB STUDIES

| | 1993-94 | 1994-95 | 1995-96 1/ | 1996-97 | 1997-98 | Discret. Draft 1998-99 6/ | Draft for Power 1998-99 6/ |
|---|---|---|---|---|---|---|---|
| PNW AREA AVG. ANNUAL LOAD (MW) | 18370.0 | 18898.0 | 18898.0 | 20324.6 | 20387.3 | 20479.6 | - |
| -Avg. Annual/Jan. Load (%) | 86.7 | 86.7 | 86.7 | 87.1 | 86.9 | 86.3 | - |
| -Avg. C.P. Load Factor (%) | 72.4 | 75.2 | 75.2 | 75.3 | 75.2 | 75.6 | - |
| -Avg. Annual Firm Exports | 969.0 | 905.0 | 905.0 | 511.2 | 926.3 | 1075.3 | - |
| -Avg. Annual Firm Surplus (MW) 2/ | 255.0 | 255.0 | 255.0 | 610.5 | 433.2 | 534.6 | - |
| THERMAL INSTALLATIONS (MW) 3/ | | | | | | | |
| -January Peak Capability | 9220 | 9225 | 9225 | 10381 | 10514 | 11003 | - |
| -Critical Period (C.P.) Energy | 6256 | 6491 | 6491 | 7975 | 8141 | 8462 | - |
| -C.P. Minimum Generation | 1881 | 1621 | 1621 | 675 | 632 | 789 | - |
| -Avg. Annual System Export Sales | 1146 | 1440 | 1440 | 887 | 1133 | 1265 | - |
| -Avg. Ann. Displaceable Market | 2689 | 3462 | 3462 | 6104 4/ | 6105 | 6345 | - |
| INSTALLED HYDRO CAPACITY (MW) | 29745 | 29680 | 29680 | 29785 | 29786 | 29786 | - |
| -Base System | 23806 | 23736 | 23736 | 23841 | 23856 | 23856 | - |
| STEP I/II/III C.P. (MONTHS) | 42/20/5.5 | 42/20/6 | 42/20/6 | 42/20/7 | 42/20/6 | 42/20/5.5 | 42/20/6.5 |
| BASE STREAMFLOWS AT THE DALLES (cfs) 5/ | | | | | | | |
| -Step I 50-yr.Avg. Streamflow | 178235 | 179502 | 179502 | 179338 | 180748 | 181664 | - |
| -Step I C.P. Average | 112843 | 113177 | 113177 | 113053 | 114127 | 114496 | - |
| -Step II C.P. Average | 99548 | 100146 | 100146 | 100036 | 101008 | 101537 | - |
| -Step III C.P. Average | 57498 | 64733 | 64733 | 64756 | 64870 | 57185 | 58483 |
| CAPACITY BENEFITS (MW) | | | | | | | |
| -Step II C.P. Generation | 8869.5 | 8892.9 | 8892.9 | 8963.5 | 9018.0 | 9064.1 | - |
| -Step III C.P. Generation | 7036.3 | 7113.5 | 7113.5 | 6895.5 | 7169.4 | 7061.2 | 6773.9 |
| -Step II Gain over Step III | 1833.2 | 1779.4 | 1779.4 | 2068.0 | 1848.6 | 2002.9 | 2290.2 |
| -CANADIAN ENTITLEMENT | 1266.5 | 1183.4 | 1183.4 | 1373.4 | 1229.6 | 1324.7 | 1514.7 |
| -Change due to Mica Reop | -2.3 | 0.7 | 0.7 | 1.0 | 0.0 | -0.4 | - |
| -Benefit in Sales Agreement | 755.0 | 666.0 | 576.0 | 486.0 | 471.0 | 416.0 | - |
| ENERGY BENEFITS (aMW) | | | | | | | |
| -Step II Firm Hydro | 8970.2 | 8928.3 | 8928.3 | 8871.0 | 8963.0 | 9000.0 | - |
| -Step II Thermal Displacement | 1148.2 | 1422.3 | 1422.3 | 2037.4 | 2037.7 | 2101.3 | - |
| -Step II Other Usable | 492.8 | 421.0 | 421.0 | 207.0 | 194.9 | 188.3 | - |
| -Step II Total Usable | 10611.1 | 10771.6 | 10771.6 | 11115.4 | 11195.6 | 11289.6 | - |
| -Step III Firm Hydro | 6485.2 | 6401.4 | 6401.4 | 6445.0 | 6579.0 | 6502.1 | - |
| -Step III Thermal Displacement | 1783.1 | 2123.8 | 2123.8 | 2951.6 | 2902.9 | 3066.8 | - |
| -Step III Other Usable | 1031.4 | 940.0 | 940.0 | 623.7 | 607.2 | 595.3 | - |
| -Step III Total Usable | 9299.7 | 9465.2 | 9465.2 | 10020.3 | 10089.1 | 10164.2 | - |
| -CANADIAN ENTITLEMENT | 655.7 | 653.2 | 653.2 | 547.5 | 553.3 | 562.7 | - |
| -Change due to Mica Reoperation | 4.6 | -2.0 | -2.0 | -0.9 | -2.8 | -4.1 | - |
| -ENTITLEMENT in Sales Agreement | 293.0 | 279.0 | 268.0 | 254.0 | 246.0 | 215.0 | - |
| STEP II PEAK CAPABILITY (MW) | 30579 | 30530 | 30530 | 31472 | 31647 | 32074 | - |
| STEP II PEAK LOAD (MW) | 24414 | 24069 | 24069 | 26252 | 26587 | 27317 | - |
| STEP III PEAK CAPABILITY (MW) | 30429 | 30299 | 30299 | 31409 | 31456 | 31793 | - |
| STEP III PEAK LOAD (MW) | 20593 | 20273 | 20273 | 22350 | 22859 | 23391 | - |

FOOTNOTES FOR TABLE 7

1. The 1994-95 AOP was carried foreword and adopted for the 1995-96 AOP.

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

3. Thermal installations include all existing and planned thermal resources. Beginning with the 1994-95 Assured Operating Plan, thermal installations also included thermal imports. Beginning with the 1996-97 Assured Operating Plan, thermal installations also included cogeneration, renewable thermal, thermal NUG/PURPA, and seasonal exchange imports minus plant sales.

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

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

6. Beginning in 1998-99, two columns are shown to indicate differences in some values which occur because of the two interpretations of the critical stream flow period for the Step III system.

# CHART 1

1998-99 DETERMINATION OF 30 YEAR MONTHLY HYDRO GENERATION (aMW)