Non-Treaty Storage Agreement

Technical Report: Appendices A - L

Bonneville
POWER ADMINISTRATION

March 1990

APPENDIX D

POWER SYSTEM EFFECTS SUPPORTING MATERIAL

TABLE FORMAT

YEAR - Contract year in SAM study.

CASE - No-Action alternative or proposal used as opportunity storage or as a firm resource.

HYDRO - PNW hydrosystem generation (MW).

NUC - Nuclear generation (MW)

COAL - Coal plant generation (MW)

CT - Combustion turbine generation (MW)

NTRTY - Energy produced from release of U.S. non-Treaty storage

OTHER - Exchange energy plus storage outside PNW

GENCT - Generic CT generation (MW)

BC/NW - Purchases by the PNW from BC Hydro (MW).

TOTAL - Total generation from sources listed in Table.

COMPARISON OF PNW GENERATION MIX BY YEAR (BASE CASE)
(AVG ANNUAL MW)

YEAR	CASE	HYDRO	NUC	COAL	CT	NTRTY	OTHER	GENCT	BC/NW	TOTAL
1989	No-Action	16286.8	1544.3	2300.5	46.8	36.9	0.0	0.0	80.1	20295.4
Change Resulting from Proposal										
	Opportunity	-0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.1	-0.2
	Firm	-13.6	0.0	50.4	17.5	-7.0	0.0	0.0	21.5	68.8
1990	No-Action	16211.6	1543.8	2514.0	51.8	107.7	0.0	0.0	103.9	20532.8
Change Resulting from Proposal										
	Opportunity	-40.6	0.0	-34.2	-15.2	133.4	0.0	0.0	-8.3	35.1
	Firm	24.3	0.0	2.8	11.1	-23.0	0.0	0.0	55.3	70.5
1991	No-Action	16220.8	1542.8	2752.1	54.8	130.1	0.0	0.0	86.3	20786.9
Change Resulting from Proposal										
	Opportunity	-44.2	0.0	29.1	-7.6	94.0	0.1	0.0	-10.5	60.9
	Firm	47.1	0.0	36.8	5.4	-39.3	0.0	0.0	44.0	94.0
1992	No-Action	16442.8	1540.0	2805.5	34.2	137.2	1.5	0.0	93.1	21054.3
Change Resulting from Proposal										
	Opportunity	-33.8	0.0	16.0	-7.3	92.1	0.0	0.0	-20.0	47.0
	Firm	44.9	0.0	41.6	17.8	-54.0	-0.3	0.0	34.1	84.1
1993	No-Action	16445.3	1556.1	3112.1	28.0	135.4	2.1	0.0	109.8	21388.8
Change Resulting from Proposal										
	Opportunity	-48.4	0.0	5.2	-5.0	108.3	0.1	0.0	-19.1	41.1
	Firm	6.9	0.0	49.1	1.5	-33.7	0.0	0.0	36.4	60.2
1994	No-Action	16199.6	1545.0	3364.1	41.6	0.0	5.8	0.0	116.4	21272.5
Change Resulting from Proposal										
	Opportunity	-120.3	0.0	12.1	-10.9	245.8	-0.3	0.0	-3.2	123.2
	Firm	-65.6	0.0	22.3	-1.7	114.0	-0.2	0.0	45.5	114.3
1995	No-Action	16248.5	1551.4	3371.9	50.0	0.0	11.4	0.0	159.3	21392.5
Change Resulting from Proposal										
	Opportunity	-135.3	0.0	66.6	-10.0	188.3	0.4	0.0	-13.2	96.8
	Firm	-104.8	0.0	64.8	-1.4	117.7	0.3	0.0	32.8	109.4
1996	No-Action	16407.6	1548.3	3321.3	52.8	0.0	20.4	0.0	135.4	21485.8
Change Resulting from Proposal										
	Opportunity	-139.5	0.0	85.5	-15.5	189.4	0.3	0.0	-26.5	93.7
	Firm	-104.8	0.0	65.6	-1.0	112.3	0.2	0.0	36.8	109.1
1997	No-Action	16452.4	1548.5	3493.1	114.1	0.0	16.1	0.0	109.3	21733.5
Change Resulting from Proposal										
	Opportunity	-173.9	0.0	108.9	-39.8	177.5	0.3	0.0	-20.8	52.2
	Firm	-92.9	0.0	71.6	-0.7	99.4	0.2	0.0	27.0	104.6
1998	No-Action	16714.3	1544.8	3438.7	101.9	0.0	17.0	0.0	68.5	21885.2
Change Resulting from Proposal										
	Opportunity	-178.6	0.0	78.3	-29.7	159.1	0.4	0.0	-13.7	15.8
	Firm	-90.9	0.0	61.2	1.3	96.3	-0.3	0.0	18.9	86.5

1999	No-Action	16404.7	2345.3	3483.7	110.6	0.0	2.8	0.0	64.8	22411.9
Change Resulting from Proposal										
	Opportunity	-145.9	0.0	73.0	-33.8	153.1	0.3	0.0	-14.4	32.3
	Firm	-77.2	0.0	62.9	1.3	85.3	0.1	0.0	20.6	93.0
2000	No-Action	16769.1	2355.0	3473.4	121.0	0.0	6.7	0.0	77.3	22802.5
Change Resulting from Proposal										
	Opportunity	-157.9	0.0	76.8	-15.5	183.1	0.4	0.0	-20.0	66.9
	Firm	-102.0	0.0	70.1	4.8	87.8	-0.9	0.0	24.7	84.5
2001	No-Action	16558.7	2373.5	3634.3	140.9	0.0	21.3	0.0	65.4	22794.1
Change Resulting from Proposal										
	Opportunity	-151.2	0.0	65.2	-24.9	207.8	0.6	0.0	-10.3	87.2
	Firm	-99.8	0.0	56.5	-4.8	102.2	0.3	0.0	36.0	90.4
2002	No-Action	16377.1	2363.7	3578.0	139.0	0.0	22.6	0.0	58.0	22538.4
Change Resulting from Proposal										
	Opportunity	-145.3	0.0	44.0	-38.0	204.0	-0.4	0.0	-14.9	49.4
	Firm	-108.8	0.0	43.2	1.1	105.1	-1.4	0.0	30.9	70.1
2003	No-Action	16590.4	3168.0	3520.2	105.9	0.0	11.5	0.0	70.7	23466.7
Change Resulting from Proposal										
	Opportunity	-179.1	0.0	82.6	-22.6	163.5	-0.2	0.0	-11.7	32.5
	Firm	-77.3	0.0	67.7	6.1	77.5	-0.6	0.0	14.0	87.4
2004	No-Action	16769.2	3176.4	3529.4	118.7	0.0	13.0	0.0	89.3	23696.0
Change Resulting from Proposal										
	Opportunity	-149.5	0.0	81.3	-19.4	202.6	0.0	0.0	-32.9	82.1
	Firm	-85.7	0.0	65.6	1.0	84.3	-0.8	0.0	24.3	88.7
2005	No-Action	16595.0	3182.1	3517.2	136.1	0.0	22.7	0.0	82.1	23535.2
Change Resulting from Proposal										
	Opportunity	-156.8	0.0	69.2	-25.3	218.1	0.1	0.0	-18.8	86.5
	Firm	-92.6	0.0	55.1	-2.6	89.1	-0.7	0.0	37.0	85.3
2006	No-Action	16451.5	3168.1	3720.2	131.1	0.0	21.8	0.0	87.2	23579.9
Change Resulting from Proposal										
	Opportunity	-151.1	0.0	70.7	-21.5	207.9	-0.5	0.0	-27.7	77.8
	Firm	-80.8	0.0	64.5	7.5	87.4	-0.7	0.0	3.8	81.7
2007	No-Action	16541.0	3189.1	3972.3	130.7	0.0	19.7	0.0	67.9	23920.7
Change Resulting from Proposal										
	Opportunity	-177.9	0.0	66.0	-20.2	202.6	0.3	0.0	-19.8	51.0
	Firm	-102.2	0.0	57.2	14.1	86.8	-0.7	0.0	1.4	56.6
2008	No-Action	16524.0	3177.5	4149.1	135.8	0.0	21.5	0.0	78.0	24085.9
Change Resulting from Proposal										
	Opportunity	-163.9	0.0	67.8	-20.6	184.5	0.1	0.0	-16.9	51.0
	Firm	-73.4	0.0	65.7	10.9	74.2	-0.1	0.0	-7.1	70.2
AVERAGE	No-Action	16460.5	2198.2	3352.6	92.3	27.4	11.9	0.0	90.1	22232.9
Average Change Resulting from Proposal										
	Opportunity	-124.7	0.0	53.2	-19.1	165.8	0.1	0.0	-16.1	59.1
	Firm	-62.5	0.0	53.7	4.5	63.1	-0.3	0.0	26.9	85.5

(VS6-PJ-3303W)

APPENDIX E

ECONOMIC ANALYSES

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ECONOMIC ANALYSES

SAM was used to evaluate the economic benefits of the non-Treaty storage agreement measured over the 20-year study horizon, 1989 through 2008. Changes in PNW curtailment costs, PNW production costs, PNW and BC Hydro economy energy revenues, wheeling revenues to PNW, California displacement benefits, and PNW resource deferral benefits are measured relative to the No-Action alternative.

PNW curtailment costs reflect loss of revenues due to load curtailment. PNW production costs are the operating costs of generating resources, and short-term purchases from BC Hydro, if available. PNW and BC Hydro economy energy revenues are based on a regional share-the-savings revenue policy. The economy energy price is a function of California's decremental cost and the PNW incremental cost. California displacement benefits reflect the operating cost saved when California purchases economy energy from the PNW or BC Hydro to shut down California thermal generating resources. PNW resource deferral benefits are the cost savings from delaying new resource acquisitions.

All costs and benefits are expressed as net present values in 1989 dollars, using a nominal discount rate of 8.15 percent (a 5 percent inflation rate and a 3 percent real discount rate). The economy energy price is one-half the sum of the incremental cost of the PNW resource and the decremental cost of California's displaced resource. The incremental cost of PNW hydro resources is assumed to be 3 mills/kwh. Nonfirm energy (NF) and Surplus Firm Power (SP) rate projections are based on BPA's final modified SL-87 forecast.

Economic analyses are presented for opportunity storage and firm resource use of non-Treaty storage under the proposed agreement. In both cases, the proposed non-Treaty storage agreement expires in 2003. Changes in costs and revenues are measured relative to the No-Action alternative, where there is no new agreement and the present agreement expires in 1993. Even though the proposed agreement expires in 2003, the economic analysis is carried through 2008 to reflect costs of refilling non-Treaty storage. Results of the economic analyses are presented in Tables E-1 through E-5 and are discussed in the following paragraphs.

In the No-Action alternative, each party (the U.S. or BC Hydro) determines whether to store or release water from non-Treaty storage depending on market conditions. In SAM the non-Treaty storage is divided into two blocks: the upper portion may be sold at lower prices, and a lower portion is considered more valuable and may be sold at higher prices. The amount of storage in each portion varies by month to gain higher revenues. See Technical Report Section 3.1.2 for further detail of the alternatives.

<u>Opportunity Storage</u>

Opportunity storage under the proposed agreement is modeled the same as the No-Action alternative except the volume of available storage is increased from 2 MAF to 5 MAF.

The economic analysis of the proposal shows a PNW benefit of $179 million net present value. Additional non-Treaty storage space increases hydro energy usability by reshaping the generation and decreasing spill. Due to these operational changes, benefits to the PNW include decreased production costs due to additional CT displacement; decreased curtailment costs, and increased economy sales to California. BPA's wheeling revenues decrease because BC Hydro makes fewer sales to California.

The net benefit to California is $51 million net present value. Additional purchases from the PNW result in a gain in displacement benefits. BC Hydro sells less to California. In this study it is assumed that the benefit to BC Hydro of displacing Burrard, both economic and environmental, is greater than potential economy energy sales to California.

TABLE E-1
NTS ECONOMIC ANALYSIS OF OPPORTUNITY STORAGE
MEDIUM PNW LOADS
1989 NPV $ MILLIONS

NORTHWEST

a Production Cost	b Curtailment Cost	c Econ. Energy Revenues	d BC Hydro Wheeling	e Net Benefit*
-33	-21	135	-10	179

CALIFORNIA

a Purchases From BC Hydro	b Purchases From PNW	c Econ. Energy Displacement	d Net Benefit**
-64	135	122	51

Note: *Northwest Net Benefit (e) = c + d - a - b
**California Net Benefit (d) = c - a - b

BC Hydro experiences additional head losses from operating the non-Treaty storage. A portion of these head losses, estimated at 17 aMW, will be returned to BC Hydro by the U.S. Assuming BPA's NF and SP rates used in these studies as lower and upper bounds, the cost to BPA ranges from $30 to $52 million net present value, reducing PNW benefits to between $127 and $149.

Firm Resource Use

Firm resource use under the proposal assumes BPA and BC Hydro would declare non-Treaty storage as a firm resource in PNCA planning. With non-Treaty storage as a firm resource, BPA would have an obligation to refill non-Treaty storage along with the U.S. reservoirs. This declaration would increase FELCC by 165 aMW. For the firm resource alternative, three scenarios are analyzed: resource deferral - medium PNW loads; resource deferral - high PNW loads; and firm power sale.

a) <u>Firm Resource Use - Resource Deferral - Medium PNW Loads Scenario</u>

The economic analysis of firm resource use assuming medium PNW loads and PNW resource deferral shows a PNW benefit of $35 million net present value. Both production costs for the PNW and economy energy revenues increase. Since nonfirm energy is stored and converted into firm energy, there is less nonfirm to displace thermal resources. Curtailment costs decrease slightly. BPA's wheeling revenues decrease because BC Hydro has less nonfirm energy available to export.

A potential benefit of additional FELCC is resource deferral. Using the Least Cost Mix Model, the marginal resources under medium PNW loads are conservation in early years and nuclear in later years. Approximately the same amount of conservation is brought on by 2004 in both cases, and only the ramping varies by about 10 aMW. Thus there is not a significant amount of savings in deferring resources until the year 2000, when nuclear plants are brought on. Realistically, 165 aMW of energy is not enough to defer an 800 MW nuclear plant. Therefore, the LCMM shows only about $60 million net present value in savings to the PNW, assuming nuclear is not deferrable.

Because of the reduction in available economy energy from the PNW and BC Hydro, California incurs a cost of $35 million. The incremental decrease in California benefits is due to the assumption that the additional firm energy remains in the PNW and BC Hydro regions.

TABLE E-2
NTS ECONOMIC ANALYSIS OF FIRM RESOURCE USE
MEDIUM PNW LOADS
PNW RESOURCE DEFERRAL SCENARIO
1989 NPV $ MILLIONS

NORTHWEST

a Production Cost	b Curtailment Cost	c Econ. Energy Revenue	d Resource Deferral	e BC Hydro Wheeling	f Net Benefit*
52	-19	22	60	-14	35

CALIFORNIA

a Purchases from BC Hydro	b Purchases from PNW	c Econ. Energy Displacement	d Net Benefit**
-87	22	-100	-35

Note: *Northwest Net Benefit (f) = c + d + e - a - b
**California Net Benefit (d) = c - a - b

BC Hydro experiences additional head losses from operating the non-Treaty storage. A portion of these head losses, estimated at 2 aMW, will be returned to BC Hydro by the U.S. Assuming BPA's NF and SP rates used in these studies as lower and upper bounds, the cost to BPA ranges from $4 to $7 million net present value, reducing PNW benefits to between $28 and $31 million.

b) Firm Resouce Use - Firm Power Sale Scenario

If a firm power sale of 165 aMW from the PNW to California is assumed instead of deferring a resource, the PNW benefit is $117 million net present value. The PNW would receive approximately $506 million in revenues based on a firm energy rate of 28.5 mills/kwh in 1989 $. California would gain $673 million in displacement savings assuming the rate is 75 percent of their savings.

TABLE E-3
NTS ECONOMIC ANALYSIS OF FIRM RESOURCE USE
MEDIUM PNW LOADS
FIRM SALE TO CALIFORNIA SCENARIO
1989 NPV $ MILLIONS

NORTHWEST

a Production Cost	b Curtailment Cost	c Econ. Energy Revenue	d Firm Sale Revenue	e BCH Wheeling	f Net Benefit*
181	-6	-196	506	-18	117

CALIFORNIA

a Purchases from BCH	b Purchases from PNW	c Firm Sale Purchase	d Econ. Energy Displacement	e Firm Sale Displacement	f Net Benefit**
-105	-196	506	-473	673	-5

Note: *Northwest Net Benefit (f) = c + d + e - a - b
**California Net Benefit (f) = d + e - a - b - c

BC Hydro experiences additional head losses from operating the non-Treaty storage. A portion of these head losses, estimated at 2 aMW, will be returned to BC Hydro by the U.S. Assuming BPA's NF and SP rates used in these studies as lower and upper bounds, the cost to BPA ranges from $4 to $7 million net present value, reducing PNW benefits to between $110 and $113 million.

High PNW Loads Scenario

a) Opportunity Storage

Under the PNW high load scenario the marginal resources acquired are expensive short-term purchases and coal generation.

The economic analysis of the proposal shows a PNW benefit of $280 million net present value. The largest benefit to the PNW under the high PNW loads scenario is the decrease in production costs due to the displacement of combustion turbines and short-term purchases. Additionally there is a decrease in curtailment costs due to increased hydro energy from reshaping the hydro system.

California incurs a cost of $26 million net present value due to the reduction in available economy energy from the PNW and BC Hydro. The economy energy is used to displace short-term purchases in the PNW until less expensive resources are brought on line.

TABLE E-4
NTS ECONOMIC ANALYSIS OF OPPORTUNITY STORAGE
HIGH PNW LOADS
1989 NPV $ MILLIONS

NORTHWEST

a Production Cost	b Curtailment Cost	c Econ. Energy Revenues	d BC Hydro Wheeling	e Net Benefit*
-206	-38	52	-16	280

CALIFORNIA

a Purchases From BC Hydro	b Purchases From PNW	c Econ. Energy Displacement	d Net Benefit**
-112	52	-86	-26

Note: *Northwest Net Benefit (e) = c + d - a - b
**California Net Benefit (d) = c - a - b

BC Hydro experiences additional head losses from operating the non-Treaty storage. A portion of these head losses, estimated at 20 aMW, will be returned to BC Hydro by the U.S. Assuming BPA's NF and SP rates used in these studies as lower and upper bounds, the cost to BPA ranges from $33 to $62 million net present value, reducing PNW benefits to between $218 and $247 million.

b) Firm Resource Use - Resource Deferral

Under the PNW high load forecast, expensive short-term purchases and coal plants are the marginal resources and could be deferred until 2004 with substantial savings.

The economic analysis of firm resource use assuming high PNW loads and PNW resource deferral shows a PNW benefit of $305 million net present value. Production and curtailment costs for the PNW increase, and economy energy revenues drop. Since nonfirm energy is stored and converted into firm energy, there is less nonfirm to displace thermal resources or sell to secondary markets. The LCMM provides a savings of $375 million by deferring short-term purchases and coal plant additions. BPA's wheeling revenues decrease, because BC Hydro has converted nonfirm to firm energy and therefore has less available to export.

Because of the reduction in available economy energy from the PNW and BC Hydro, California incurs a cost of $72 million. The incremental decrease in California benefits is due to the assumption that the additional firm energy remains in the PNW and BC Hydro regions.

TABLE E-5
NTS ECONOMIC ANALYSIS OF FIRM RESOURCE USE
HIGH PNW LOADS
RESOURCE DEFERRAL
1989 NPV $ MILLIONS

NORTHWEST

a Production Cost	b Curtailment Cost	c Econ. Energy Revenue	d Resource Deferral	e BCH Wheeling	f Net Benefit*
19	-13	-43	375	-21	305

CALIFORNIA

a Purchases from BCH	b Purchases from PNW	c Econ. Energy Displacement	d Net Benefit**
-139	-43	-254	-72

Note: *Northwest Net Benefit (f) = c + d + e - a - b
**California Net Benefit (d) = c - a - b

BC Hydro experiences additional head losses from operating the non-Treaty storage. A portion of these head losses, estimated at 3 aMW, will be returned to BC Hydro by the U.S. Assuming BPA's NF and SP used in these studies as lower and upper bounds, the cost to BPA ranges from $5 to $9 million net present value, reducing PNW benefits to between $296 and $300 million.

(VS6-4154W)

APPENDIX F

PNW HYDROPOWER SYSTEM PLANNING AND OPERATION

APPENDIX F

PNW HYDROPOWER SYSTEM PLANNING AND OPERATION

I. INTRODUCTION

The Pacific Northwest depends on its hydroelectric power system for a large percentage of its electric power needs. The amount of runoff in this system is highly variable. The average annual runoff is about 134 million acre-feet (MAF), but in the past has varied from a low of about 78 MAF to a high of 193 MAF. The monthly mean streamflow (unregulated), as measured at the Dalles, Oregon, can range from 40,000 cfs in January to 1,240,000 cfs in May.

The hydro system consists of many small "run-of-river" projects with limited daily or weekly storage, and a few much larger "seasonal storage" projects whose storage may be drawn upon over a year or more before emptying or refilling. Since streamflows do not occur in the same pattern as electric energy requirements, the water is used as a storage medium for potential energy. The streamflow pattern is regulated into a more usable shape by controlling project outflow to store energy when natural streamflows exceed load requirements, and to release stored energy as needed. The total storage capacity of the system is only about 42 MAF, nearly half of which is located in Canada. The Canadian portion of the storage is operated by BC Hydro, with the U.S. rights determined by the Columbia River Treaty. Because of the low storage capacity compared with runoff, the hydro system has the potential of producing about 12,000 average megawatts (aMW) of energy as "firm" during low runoff conditions. It can generate about 16,000 average MW on a long-term average basis, and about 19,000 average MW in a high runoff year. This means that in planning the coming year there is an additional unknown factor; up to 7,000 aMW of nonfirm energy that may or may not be available.

II. SEASONAL PLANNING

The operational planning of Pacific Northwest hydro system is based on the Pacific Northwest Coordination Agreement (PNCA). The PNCA is a contract among the parties to that agreement that defines how planning and operation of the hydro system is carried out on a coordinated basis. The Treaty reservoir storage space in Canada is included in the PNCA planning process and is operated to rule curves and refill requirements similar to other Pacific Northwest reservoirs. Planning is based on the "critical period," which is that period using the historical streamflow data base during which the hydro system can produce the least amount of power while drafting the water in the reservoirs allocated to power from full to empty. The amount of power produced under critical water conditions is called "firm." The critical period itself is most often defined as the 42 months of low streamflow from September 1, 1928, through February 29, 1932. This represents the level of risk that the regional utilities have contractually agreed upon under the PNCA in relying on the hydro system to produce firm energy. Since flows are usually better than what occurs under critical water conditions, the amount of additional power produced is called "nonfirm." If all the runoff could be stored in any streamflow runoff year, as is the case with some other large hydro power systems in the U.S., the hydro system could always produce an average amount of power, and firm energy would be based on average runoff.

The flexibility of the hydro system to "shape" generation to meet load is limited by many constraints. Constraints modeled in the planning process include upper storage limits for flood control or recreation, project minimum and maximum outflows, tailwater restrictions, spills of water from dams to transport juvenile fish around (rather than through) the turbines, and the water set aside for increased streamflows to aid in the downstream migration of fish (the Water Budget). While meeting these and other constraints, hydro system flexibility is used wherever possible for power operations. By drafting reservoirs earlier in the year to meet higher loads, energy is shifted forward in time, or "borrowed" from the future, up to certain limits. While thermal plants are meeting base loads, the hydro system is meeting both base and peak loads. Nighttime constraints on the ability to refill plants that have storage capability further limit the system. Operational constraints limit the ability to shift firm energy within the critical period. These constraints place limits on the amount of reservoir drawdown permitted at certain times during the year.

In planning for each coming operating year, Northwest utilities prepare a critical period study in accordance with the PNCA. This study defines certain operational parameters called critical rule curves under which the system will operate. A critical rule curve for a reservoir is a schedule of the end-of-month storage contents attained by that reservoir in the critical period study. Critical rule curves are designed to protect the ability of the hydro system to serve firm load with the occurrence of flows no worse than those of the critical period. For each reservoir, there is a set of four rule curves showing storage contents, one rule curve for each year from July 1928, through June 1932. The critical period study shows how the system would operate if all the loads and resources were in place as forecasted and the historical critically low streamflows reoccur. The study also defines the amount of load the system can serve on a firm basis (the firm energy load carrying capability, or FELCC). Operationally, the system reservoirs are drafted proportionately with respect to each reservoir's critical rule curves under noncritical, but highly variable, streamflow conditions.

III. OPERATIONS

The critical rule curves are used along with reservoir refill requirements to develop the generation needed to meet the FELCC regardless of the amount of streamflow that actually occurs. For example, if the flows during the given month are less than the flows used in the critical period study, the system reservoirs would be drafted proportionately according to each reservoir's critical rule curves taking into consideration each project's refill probability. If the flows are higher, but the reservoirs are lower than the rule curves, then the reservoirs could be proportionately filled to the rule curve while meeting firm loads. If the system is surplus when compared with critical water conditions, then nonfirm energy would be offered to displace higher cost Northwest thermal resources, exported out of the region, stored in reservoirs, or spilled. Note, however, that the Northwest under the PNCA would not draft the reservoirs below their rule curves to serve nonfirm markets because that would jeopardize the system's ability to meet its FELCC in the remainder of the operating year. In addition, this would also impair the ability of the system to refill all reservoirs by July 31 of each year.

Ideally, the system refills each summer. By late summer, in most years, the snowpack in the region has melted, causing the streamflows to recede sharply. In order to continue meeting FELCC, reservoirs must be drafted. In some years, climatic conditions are such that the system is surplus and some nonfirm energy is available in the fall or early winter. In January, the first snowpack measurements and the first forecasts of the January through July runoff are made. Flood control curves are developed to prevent flooding in the spring and refill requirements are developed so as to insure that firm loads are met and system reservoirs are refilled by July 31. This would not be difficult if accurate forecasts of the January through July runoff were available. However, the January forecast is based on actual snowpack and projected precipitation through July. The future precipitation can vary greatly from projections and since most storage reservoirs and drainage areas are relatively remote, little accurate data are available on the amount of snowpack loss or gain between snowpack surveys. Even with January through July runoff projections updated monthly, a project may run at maximum generation one month for flood control, and then because of an unexpectedly low snowpack measurement, be run at minimum the next month in order to refill. The closer to July, the more accurate the forecast, since less of it is based on future precipitation. Unfortunately, if a reservoir is drafted too much early in the season based on a high projected runoff, it may be impossible to refill if precipitation is much below normal. Likewise, if it is not drafted enough, flood control will force water to be spilled, a loss that can run to tens of thousands of dollars per hour. With an annual runoff that varies between about 60 percent and 145 percent of normal and limited storage space, hydro operations is really a continual balancing act between maximizing revenues and the need to refill annually for recreation, fisheries, and to assure future energy needs.

IV. DIFFERENCES BETWEEN HYDRO AND THERMAL SYSTEMS

A major difference between hydro and thermal systems is the time it takes to bring generation on line. A thermal plant can require hours, or even days, to reach maximum output, while hydro units can be brought on line in a few minutes. A coal or nuclear plant is limited in its ability to ramp up or down, while a hydro system can usually call upon a large number of units to be brought on line singly or in groups. A thermal plant's fuel supply can be controlled within certain limits while there is very limited control over the hydro system's "fuel" due to variations in the amount of the spring runoff, or the runoff from sudden rainstorms or snowmelts. Moreover, as previously discussed there are significant restrictions on the ability of the hydro resource to generate power because of the need to refill reservoirs, the requirements to maintain specific elevations for flood control, wildlife, recreation, navigation, or irrigation; and the requirement to provide flows for fish migration, recreation, and navigation.

V. U.S./BC Hydro Planning and Operation

The coordinated use of the Canadian Treaty Storage is governed by the Columbia River Treaty. The Treaty requires planning be done several years in advance. The minimum and maximum discharge requirements, refill requirements, and other operating requirements at Mica, Arrow, and Duncan reservoirs are established in the Assured Operating Plan (AOP) or Detailed Operating Plan (DOP). The AOP is agreed upon 6 years in advance. The DOP is agreed upon for the upcoming operating year, and contains mutually-agreed upon updates to the loads, resources, and rule curves in the AOP. If the update cannot be agreed upon, then the AOP operation is used for the DOP. The U.S. guidelines are specified in the DOP. The Canadians however have the flexibility to operate their projects to meet their load, provided the flows which cross the U.S./Canadian border are the same as if BC Hydro had operated according to the DOP. The Canadians may place additional operating constraints on their system such as higher minimum flow requirements at Mica which would limit the non-Treaty Storage operation.

The Mica AOP and DOP minimum discharge is 10 thousand cubic feet per second (kcfs) and the maximum discharge is 34 kcfs except during flood control operations. According to BC Hydro these flows and elevations have been exceeded as required to meet their system loads, project requirements, and flood control requirements. These adjustments to meet BC Hydro's system loads are internal to their system and do not affect flows across the U.S./Canadian border or non-Treaty storage. When flood control requirements cannot be met within the specified DOP flows, DOP maximum outflow can be increased up to, but cannot exceed, Mica's turbine capability.

Currently the Arrow Lake elevation can be increased 2 feet above normal full upon approval of BC Hydro and the BC Government Comptroller of Water Rights. The DOP minimum discharge is 5 kcfs and the maximum discharge is determined by the physical limits at the project, but is normally quite high. The DOP maximum rate of change in project outflow is 25 kcfs per day; however, in actual operation a limit of 15 kcfs is used. The outflow daily rate of change limitation of 15 kcfs also applies to non-Treaty storage transactions. These rates can be exceeded due to project maintenance requirements, BC Hydro downstream requirements, flood control, or emergency conditions.

There is no annual refill requirement on the non-Treaty space, although it is required to be refilled within 7 years after the end of the non-Treaty Storage Agreement.

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