Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Thompson Falls (1490)		None noted	No change
Noxon Rapids (1480)	Minimum Content	100.8 ksfd May-Sep 78.7 ksfd Oct-Apr Empty last year of CP	No change
Cabinet Gorge (1475)		None noted	No change
Albeni Falls (1465)	Minimum Flow	4000 cfs all periods	No change
	Minimum Content	559.1 ksfd Jun-Aug (582.4 at start of CP) 465.7 ksfd Sep 190.4 ksfd Oct and Apr 30 57.6 ksfd Nov-Apr 15 (empty at end of CP) 279.0 ksfd May	No change " " " 325.7 ksfd May
	Kokanee spawning	Draft no more than 1 ft below Nov 20 elevation through Dec 31. If project fills, draft no more than 0.5 ft Dec 31 - Mar 31 Operate between SMIN and URC	No change
	Other spill	50 cfs all periods	No change
Box Canyon (1460)		None noted	No change

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Grand Coulee (1280)	Minimum Flow	30000 cfs all periods	No change
	Minimum Content	2408.3 ksfd Jun-Sep 843.9 ksfd May 289.1 ksfd except empty at end of CP	No change " Empty at end of CP 289.1 ksfd if nonfirm is produced
	Maximum Content	2 ft operating room Sep-Nov 3 ft operating room Dec-Feb	No change
	Draft limit	1.3 feet/day (bank sloughage) (Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo. ave.)	No change
	VECC	Minimum VECC 289.1 ksfd	No minimum VECC for Inchelium Ferry, but cannot draft below 289.1 ksfd except for firm load. 289.1 was not used as a VECC limit in the studies. May 31 min VECC 843.9 ksfd (1240 ft) Jun 30 min VECC 2408.3 ksfd (1285 ft)
Chief Joseph (1270)	Other spill	500 cfs all periods	No change
Wells (1220)	Other spill	1200 cfs all periods	No change
	Fish spill	20% of flow in May	10.2 kcfs Apr 30, May, Jul, and Aug 15
Rocky Reach (1200)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010)[1]
	Fish spill	20% of flow in May	Proportional spill was removed. There is no fish spill at this project in the studies.

[1] Bypass completion date. After this date, fish spill is discontinued.

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Rock Island (1170)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010) [1]
	Fish spill	20% of flow May 4229 cfs Jul 2353 cfs Aug 15 2857 cfs Jun	Proportional spill was removed. The fixed component remains. Jul: no change Aug 15: no change Jun: no change.
Wanapum (1165)	Fish Bypass	Bypass system completion 1997	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	2200 cfs all periods	No change
	Fish spill	2.7% of flow Jul 5.5% of flow Aug 16.5% of flow May	Proportional spill was removed from the studies.
Priest Rapids (1160)	Minimum Flow	50000 cfs all periods except April and May 60000 cfs in Apr No limit noted in May	36000 cfs all periods
	Fish Bypass	Bypass system completion 2001	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	2200 cfs all periods	No change
	Fish spill	2.6% of flow Jul 5.3% of flow Aug 18.8% of flow May	Proportional spill was removed from the studies.
Brownlee (767)	Minimum Flow	5000 cfs all periods	No change
Oxbow (765)	Other spill	100 cfs all periods	No change

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Ice Harbor (502)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	740 cfs all periods	No change
	Incremental spill	2600 cfs Apr-Aug	No change
	Minimum Flow	9500 cfs Mar-Jul 7500 cfs Aug-Nov	No change
	Other	Run-of-river project	Data submitted for reservoir project. Run at fixed content although PNCA submittal was to run project at minimum operating pool Apr 1-Jul 31.
McNary (488)	Other spill	3475 cfs all periods	No change
	Incremental spill	525 cfs Apr 15-Sep 30	No change
John Day (440)	Fish Bypass		Bypass not modeled (installation data set to year 2010)[1]
	Other spill	800 cfs all periods	No change
	Incremental spill	100 cfs all periods	No change
	Fish spill	6% of flow Jul and Aug15 4% of flow Jun	Proportional spill removed
	Minimum Flow	50000 cfs Mar-Nov (for completeness) 12500 cfs Dec-Feb (for completeness) (not a factor in monthly studies)	No change
	Other	Note: AOP99 Steps II and III use JDA as a run-of-river plant at 262.5 ft	Feb 1-Oct 31 Run at 257 ft (empty, 0.0 ksfd) Nov 1-Jan 31 run at 265 ft (190.0 ksfd) (Note: AOP99 Steps II and Step III use JDA as a run-of-river plant run at 265 ft)

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
The Dalles (365)	Fish Bypass	Bypass system completion 1998	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	1300 cfs all periods	No change
	Incremental spill	2700 cfs Apr-Oct 1200 cfs Nov	No change
	Fish spill		Proportional spill removed.
	Minimum Flow	50000 cfs Mar-Nov (for completeness) 12500 cfs Dec-Feb (for completeness) (not a factor in monthly studies)	No change
Bonneville (320)	Fish Bypass	Bypass system completion 1996	Bypass not modeled (installation data set to year 2010) [1]
	Other spill	8040 cfs all periods	No change
	Incremental spill	360 cfs Mar-Nov	No change
	Fish spill		Proportional spill removed
Kootenay Lake (1665)	Minimum Flow	5000 cfs all periods	No change
Chelan (1210)	Minimum Flow	50 cfs all periods	No change
	Minimum Content	308.5 ksfd Jun-Sep (except as needed to empty at end of critical period)	June - Sep: no change 95.9 ksfd Apr 30 (except as needed to empty at end of critical period)
Couer d'Alene L. (1341)	Minimum Flow	300 cfs all periods	No change
	Minimum Content	112.5 ksfd May-Aug	No change

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Libby (1760)	Minimum flow	4000 cfs all periods	No change
	Other spill		200 cfs all periods (Not new)
	Minimum content (ksfd)	1929: 777.0 Dec, 676.6 Jan, 604.0 Feb.	1929: 776.9 Dec, 676.5 Jan, 603.6 Feb, 2147.7 Jul.
		1930: 2156.1 Jul, 652.1 Dec, 513.6 Jan 502.3 Feb-May, 1351.1 Jun.	1930: 652.0 Dec, 433.2 Jan, 389.3 Feb, 348.5 Mar, 297.4 Apr 15, 444.2 Apr 30, 499.1 May, 1344.6 Jun, 1771.9 Jul.
		1931: 1777.2 Jul, 423.2 Dec, 290.8 Jan, 192.3 Feb-Apr, 261.3 May, 803.0 Jun.	1931: 317.8 Dec, 192.2 Jan, 103.1 Feb-Apr 30 , 192.2 May, 676.5 Jun, 868.0 Jul.
		1932: 1010.3 Jul, 175.6 Dec, 108.7 Jan.	1932: 174.4 Dec, 103.1 Jan, empty at end of CP.
			(Note: Requirements as reflected in data submittal 2-1-94, used in AOP00: All Dec: 776.9 ksfd Jul 1930: No more than 373.1 ksfd lower than Jul 1929 Jul 1931: No more than 857.1 ksfd lower than Jul 1930) Mar: Implement PNCA 6(c)2(c)
	Maximum summer draft	10 ft	5 ft
	Other	Operate to meet IJC rules for Corra Linn	No change

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Dworshak (535)	Minimum flow	2000 cfs all periods except Apr and Aug 1000 cfs Aug 10000 cfs May	8800 cfs Apr 30, May, and Jul 6300 cfs Jun 1200 cfs all other periods
	Maximum flow	Inflow plus 1300 cfs Oct 1-Nov 15 25000 cfs all other periods (local flooding)	No change
	Other		Run on minimum flow or flood control observing maximum and minimum flow requirements all periods except Aug 1. Aug 1 try to meet LWG target of 50000 cfs, but draft no lower that 1520 ft. Use 1490.2 ft (218.4 ksfd) for end of critical period.
Lower Granite (520)	Bypass Date		None
	Other spill		670 cfs all periods
	Incremental spill		250 cfs Apr 15-Aug 31
	Fish spill		13.2% Apr 15 40% Apr 30 and May 27% Jun Maximum spill: 60000 cfs
	Minimum flow		11500 cfs Mar-Nov
	Other	Modeled as Run of River	Run at 733 ft (MOP) Apr 15 - Oct. Run at 738 ft all other periods

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Project Operating Procedures
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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Little Goose (518)	Bypass date		None
	Other spill		630 cfs all periods
	Incremental spill		250 cfs Apr 15-Aug 31
	Fish spill		13.2% Apr 15 40% Apr 30 and May 27% Jun
	Maximum spill		30000 cfs
	Minimum flow		11500 cfs Mar-Nov
	Other	Modeled as Run of River	Run at 633 ft (Apr 15-Aug 31) Run at 638 ft all other periods
Lower Monumental (504)	Bypass Date		A bypass date of 2010 was assumed.
	Other spill		750 cfs all periods
	Fish spill		13.4% Apr 15 40.5% Apr 30 and May 27.1% Jun
	Maximum spill		30000 cfs
	Minimum flow		11500 cfs Mar-Nov
	Other	Modeled as Run of River	Run at 537 ft Apr 15-Aug 31 Run at 540 ft all other periods

Appendix A2
(Metric Units)
Project Operating Procedures
1997-98 & 2000-01 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Hungry Horse (1530)	Minimum Flow	99.11 m^3/s at Columbia Falls all months 4.11 m^3/s minimum project discharge	No change
	Maximum Flow	127.43 m^3/s at Columbia Falls Oct 15-Dec 15 192.55 m^3/s June, July and Aug. for fishing	No change
	Minimum Content	1930: 2839.0 hm^3 Jul, 766.8 hm^3 Dec 1930: Jan - Jun (hm^3) as follows: 585.7/ 474.2 / 273.3 / 330.8 / 632.0 / 965.9 / 1425.4 1931: 1,604.5 hm^3 Jul, 585.7 hm^3 Dec 1931: Jan - Jun (hm^3) as follows: 474.2 / 369.4 / 168.8 / 168.8 / 168.8 / 1036.4 / 1263.2 1932: 897.7 hm^3 Jul	No change
	Other	25.91 m draft limit for resident fish implemented as minimum VECC limit of 1,698.9 hm^3	No change
Kerr (1510)	Minimum Flow	90.61 m^3/s all periods	113.27 m^3/s Dec-Feb 339.80 m^3/s May 16-Jun 15 (monthly ave used was 219.23 m^3/s May and 215.21 m^3/s June) 90.61 m^3/s all other periods
	Maximum Flow		566.34 m^3/s Aug, Sep, and Apr 424.75 m^3/s Oct, Nov, Mar 509.70 m^3/s Dec, Jan, Feb 1132.67 m^3/s May - Jun 849.50 m^3/s July
	Minimum Content	1503.9 hm^3 Jun - Sep 1043.0 hm^3 May Empty Apr 15	No change
	Other	Conditions permitting, should be on or about 878.74 m (empty) Apr 15	No change

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Thompson Falls (1490)		None noted	No change
Noxon Rapids (1480)	Minimum Content	246.6 hm^3 May - Sep 192.6 hm^3 Oct - Apr Empty last year of CP	No change
Cabinet Gorge (1475)		None noted	No change
Albeni Falls (1465)	Minimum Flow	113.27 m^3/s all periods	No change
	Minimum Content	1367.9 hm^3 Jun-Aug (1424.9 at start of CP) 1139.4 hm^3 Sep 465.8 hm^3 Oct and Apr 30 140.9 hm^3 Nov-Apr 15 (empty at end of CP) 682.6 hm^3 May	No change " " " 796.9 hm^3 May
	Kokanee spawning	Draft no more than 0.30 m below Nov 20 elevation through Dec 31. If project fills, draft no more than 0.15 m Dec 31 - Mar 31 Operate between SMIN and URC	No change
	Other spill	1.42 m^3/s all periods	No change
Box Canyon (1460)		None noted	No change

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(Metric Units)
Project Operating Procedures
1997-98 & 2000-01 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Grand Coulee (1280)	Minimum Flow	849.50 m^3/s all periods	No change
	Minimum Content	5892.1 hm^3 Jun-Sep 2064.7 hm^3 May 707.3 hm^3 except empty at end of CP	No change " Empty at end of CP 707.3 hm^3 if nonfirm is produced
	Maximum Content	0.61 m operating room Sep-Nov 0.91 m operating room Dec-Feb	No change
	Draft limit	0.40 m/day (bank sloughage) (Constraint submitted as 0.46 m/day interpreted as 0.40 m/day mo. ave.)	No change
	VECC	Minimum VECC 707.3 hm^3.	No minimum VECC for Inchelium Ferry, but cannot draft below 707.3 hm^3 except for firm load. 707.3 hm^3 was not used as a VECC limit in the studies. May 31 min VECC 2064.7 hm^3 (377.95 m) Jun 30 min VECC 5892.1 hm^3 (391.67 m)
Chief Joseph (1270)	Other spill	14.16 m^3/s all periods	No change
Wells (1220)	Other spill	33.98 m^3/s all periods	No change
	Fish spill	20% of flow in May	288.83 m^3/s Apr 30, May, Jul, and Aug 15
Rocky Reach (1200)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010)[1]
	Fish spill	20% of flow in May	Proportional spill was removed. There is no fish spill at this project in the studies.

[1] Bypass completion date. After this date, fish spill is discontinued.

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(Metric Units)
Project Operating Procedures for the 1997-98 & 2000-01
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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Rock Island (1170)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010)[1]
	Fish spill	20% of flow May 119.75 m^3/s Jul 66.63 m^3/s Aug 15 80.90 m^3/s Jun	Proportional spill was removed. The fixed component remains. Jul: no change Aug15: no change Jun: no change
Wanapum (1165)	Fish Bypass	Bypass system completion 1997	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	62.30 m^3/s in all periods	No change
	Fish spill	2.7% of flow Jul 5.5% of flow Aug 16.5% of flow May	Proportional spill was removed from the studies
Priest Rapids (1160)	Minimum Flow	1415.84 m^3/s all periods except Apr and May 1699.01 m^3/s in Apr No limit noted in May	1019.41 m^3/s all periods
	Fish Bypass	Bypass system completion 2001	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	62.30 m^3/s all periods	No change
	Fish spill	2.6% of flow Jul 5.3% of flow Aug 18.8% of flow May	Proportional spill was removed from the studies.
Brownlee (767)	Minimum Flow	141.58 m^3/s all periods	No change
Oxbow (765)	Other spill	2.83 m^3/s all periods	No change

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(Metric Units)
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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Ice Harbor (502)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010) [1]
	Other spill	20.95 m^3/s all periods	No change
	Incremental spill	73.62 m^3/s Apr - Aug	No change
	Minimum Flow	269.01 m^3/s Mar-Jul 212.38 m^3/s Aug-Nov	No change
	Other	Run-of-river project	Data submitted for reservoir project. Run at fixed content although PNCA submittal was to run project at minimum operating pool Apr 1-Jul 31.
McNary (488)	Other spill	98.40 m^3/s all periods	No change
	Incremental spill	14.87 m^3/s Apr 15-Sep 30	No change
John Day (440)	Fish Bypass		Bypass not modeled (installation data set to year 2010) [1]
	Other spill	22.65 m^3/s all periods	No change
	Incremental spill	2.83 m^3/s all periods	No change
	Fish spill	6% of flow Jul and Aug15 4% of flow Jun	Proportional spill removed
	Minimum Flow	1415.84 m^3/s Mar-Nov (for completeness) 353.96 m^3/s Dec-Feb (for completeness) (not a factor in monthly studies)	No change
	Other	Note: AOP99 Steps II and III use JDA as a run-of-river plant at 80.01 m	Feb 1-Oct 31 Run at 78.33 m (empty, 0.0 hm^3) Nov 1-Jan 31 run at 80.77 m (464.9 hm^3) (Note: AOP99 Steps II and III use JDA as a run-of-river plant run at 80.77 m)

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
The Dalles (365)	Fish Bypass	Bypass system completion 1998	Bypass not modeled (installation data set to year 2010) [1]
	Other spill	36.81 m^3/s all periods	No change
	Incremental spill	76.46 m^3/s Apr-Oct 33.98 m^3/s Nov	No change
	Fish spill		Proportional spill removed.
	Minimum Flow	1415.84 m^3/s Mar-Nov (for completeness) 353.96 m^3/s Dec-Feb (for completeness) (not a factor in monthly studies)	No change
Bonneville (320)	Fish Bypass	Bypass system completion 1996	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	227.67 m^3/s all periods	No change
	Incremental spill	10.19 m^3/s Mar - Nov	No change
	Fish spill		Proportional spill removed
Kootenay Lake (1665)	Minimum Flow	141.58 m^3/s all periods	No change
Chelan (1210)	Minimum Flow	1.42 m^3/s all periods	No change
	Minimum Content	754.8 hm^3 Jun-Sep (except as needed to empty at end of critical period)	June - Sep: no change 234.6 hm^3 Apr 30 (except as needed to empty at end of critical period)
Couer d'Alene L. (1341)	Minimum Flow	8.50 m^3/s all periods	No change
	Minimum Content	275.2 hm^3 May-Aug	No change

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Libby (1760)	Minimum flow	113.27 m^3/s all periods	No change
	Other spill		5.66 m^3/s all periods (Not new)
	Minimum content (hm^3)	1929: 1901.0 Dec, 1655.4 Jan, 1477.7 Feb.	1929: 1900.8 Dec, 1655.1 Jan, 1476.8 Feb, 5254.6 Jul.
		1930: 5275.1 Jul, 1595.4 Dec, 1256.6 Jan, 1228.9 Feb-May, 3305.6 Jun.	1930: 1595.2 Dec, 1059.9 Jan, 952.5 Feb, 852.6 Mar, 727.6 Apr 15, 1086.8 Apr 30, 1221.1 May, 3289.7 Jun, 4335.1 Jul.
		1931: 4348.1 Jul, 1035.4 Dec, 711.5 Jan, 470.5 Feb-Apr, 639.3 May, 1964.6 Jun.	1931: 777.5 Dec, 470.2 Jan, 252.2 Feb-Apr 30, 470.2 May, 1655.1 Jun, 2123.6 Jul.
		1932: 2471.8 Jul, 429.6 Dec, 265.9 Jan.	1932: 426.7 Dec, 252.2 Jan, empty at end of CP
			(Note: Requirements as reflected in data submittal 2-1-94, used in AOP00: All Dec: 1900.8 hm^3 Jul 1930: No more than 912.8 hm^3 lower than Jul 1929 Jul 1931: No more than 2097.0 hm^3 lower than Jul 1930) Mar: Implement PNCA 6(c)2(c)
	Maximum summer draft	3.05 m	1.52 m
	Other	Operate to meet IJC rules for Corra Linn	No change

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(Metric Units)
Project Operating Procedures for the 1997-98 & 2000-01 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Dworshak (535)	Minimum flow	56.63 m^3/s all periods except Apr and Aug 28.32 m^3/s Aug 283.17 m^3/s May	249.19 m^3/s Apr 30, May, & Jul 178.40 m^3/s Jun. 33.98 m^3/s all other periods
	Maximum flow	Inflow plus 36.81 m^3/s Oct 1-Nov 15 707.92 m^3/s all other periods (local flooding)	No change
	Other		Run on minimum flow or flood control observing maximum and minimum flow requirements all periods except Aug1. Aug 1 try to meet LWG target of 1415.84 m^3/s, but draft no lower that 463.30 m. Use 454.21 m (534.34 hm^3) for end of critical period.
Lower Granite (520)	Bypass Date		None
	Other spill		18.97 m^3/s all periods
	Incremental spill		7.08 m^3/s Apr 15-Aug 31
	Fish spill		13.2% Apr 15 40% Apr 30 and May 27% Jun Maximum spill: 1699.01 m^3/s
	Minimum flow		325.64 m^3/s Mar-Nov
	Other	Modeled as Run of River	Run at 223.42 m (MOP) Apr 15-Oct. Run at 224.94 m all other periods

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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project	Constraint	Requirement 1997-98	Requirement 2000-01
Little Goose (518)	Bypass date		None
	Other spill		17.84 m^3/s all periods
	Incremental spill		7.08 m^3/s Apr 15-Aug 31
	Fish spill		13.2% Apr15 40% Apr 30 and May 27% Jun
	Maximum spill		849.50 m^3/s
	Minimum flow		325.64 m^3/s Mar-Nov
	Other	Modeled as Run of River	Run at 192.94 m Apr 15-Aug 31 Run at 194.46 m all other periods
Lower Monumental (504)	Bypass Date		A bypass date of 2010 was assumed.
	Other spill		21.24 m^3/s all periods
	Fish spill		13.4% Apr 15 40.5% Apr 30 and May 27.1% Jun
	Maximum spill		849.50 m^3/s
	Minimum flow		325.64 m^3/s Mar-Nov
	Other	Modeled as Run of River	Run at 163.68 m Apr 15-Aug 31 Run at 164.59 m all other periods

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2000-01

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January 2000

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 the downstream power benefit computations developed from the 2000-01 Assured Operating Plan (AOP).

The procedures followed in the benefit studies are those provided in Article VII; Annex A, paragraph 7, and Annex B of the Treaty; in paragraphs VIII, IX, and X of the Protocol; and in the following Entity agreements:

- The "Columbia River Treaty Entity Agreement on Resolving the Dispute on Critical Period Determination, the Capacity Entitlement for the 1998-99, 1999-00, and 2000-01 AOP/DDPB's, and Operating Procedures for the 2001-02 and Future AOP's," signed 29 August 1996;
- The "Columbia River Treaty Entity Agreement on the 1998/99, 1999/2000, and 2000/2001 Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 5 April 1995;
- The "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated December 1991; and
- 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).

The Canadian Entitlement Benefits were computed from the following studies:[1]

Step I -- Operation of the total United States of America planned hydro and thermal system, with 15.5 million acre-feet (Maf) (19.12 cubic kilometers (km^3)) of Canadian storage operated for flood control and optimum power generation in both countries.

Step II -- Operation of the Step I thermal system, the United States base hydro system, and 15.5 Maf (19.12 km^3) of Canadian storage operated for flood control and optimum power generation in both countries.

Step III -- Operation of the Step I thermal system and the United States base hydro system operated for flood control and optimum power generation in the United States.

[1] The Treaty defines the Canadian storage precisely in English units. The metric conversion is a rounded approximation.

As part of the DDPB for the operating year 2000-01, 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).

Since the Canadian Entitlement Purchase Agreement was based on the operation of Canadian Treaty storage for optimum power generation in the U.S. only (U.S. Optimum), the decrease in the downstream power benefits resulting from the operation of Canadian Treaty storage for Joint Optimum power generation 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 Joint Optimum):

Dependable Capacity	= 1447.3 MW
Average Annual Usable Energy	= 508.4 aMW

All downstream power benefits computations are rounded to the nearest tenth of a megawatt.

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 2000-01 operating year are based on the formula: Minimum Canadian Entitlement = X - (Y - Z). The quantities X, Y, and Z, expressed in terms of entitlement to downstream power benefits, are computed as follows:

X = One-half of the downstream power benefits derived from the difference between the 1999-00 Step II Joint Optimum study and Step III study.

Y = One-half of the downstream power benefits derived from the difference between the 1999-00 Step II U.S. Optimum study and Step III study.

Z = One-half of the downstream power benefits derived from the difference between the 2000-01 Step II U.S. Optimum study with 15 Maf (18.50 km^3) of Canadian storage and the Step III study.

The purpose of this formula is to set a lower limit on the Canadian Entitlement for the re-operation of Canadian storage. This minimum is based on the previous operating year Canadian Entitlement, plus the removal of 0.5 Maf (0.62 km^3) of

Canadian storage, and taking out the effect due to changes in loads, resources, and other operating procedures.

The quantities X and Y were computed in the 1999-00 DDPB Table 5. The quantity Z is computed in Table 5 of this report. The computation of the Minimum Canadian Entitlement is as follows:

Dependable Capacity	= 1461.9 - (1461.7 - 1427.5) = 1427.7 MW
Average Annual Usable Energy	= 559.5 - (560.3 - 502.3) = 501.5 aMW

The computed Canadian Entitlement exceeds these amounts.

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

The Canadian Entitlement to downstream power benefits was purchased by the Columbia Storage Power Exchange (CSPE) pursuant to 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 expired 31 March 1998 for Duncan, 31 March 1999 for Arrow, and will expire 31 March 2003 for Mica.

The studies developed for this sale included the assumption of operation of Treaty storage for optimum power generation only in the United States of America (U.S. Optimum). The Canadian Entitlement determined from the 2000-01 AOP for this condition was:

Dependable Capacity	= 1447.3 MW
Average Annual Usable Energy	= 507.7 aMW

Because the 2000-01 AOP 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 an <u>increase</u> in the energy Entitlement of 0.7 aMW and <u>no change</u> in the capacity.

Since the sale of the downstream power benefits attributable to Duncan and Arrow expires 31 March 1998 and 31 March 1999 respectively, the United States Entity is entitled to that portion of the decrease in the Canadian Entitlement attributed to Mica. Because there was no decrease in Canadian Entitlement, the United States Entity is not entitled to any compensation attributed to the re-operation of Mica. Accordingly, the Entities are agreed that the United States Entity is not entitled to receive any energy or dependable capacity during the period 1 April 2000 through 31 March 2001, from B.C. Hydro & Power Authority, in accordance with Sections 7 and 10 of the CEPA.

5. Canadian Entitlement Return

As noted above, 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 the 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 storages provided by that storage as set out in Article II of the Treaty.

The storage volume in Duncan is 1.4 Maf (1.73 km^3), in Arrow is 7.1 Maf (8.76 km^3), and the whole of Canadian storage is 15.5 Maf (19.12 km^3). Therefore, the obligation of the United States to deliver Canadian Entitlement to Canada for operating year 2000-01 beginning 1 August 2000 and ending 31 July 2001, based on the Joint Optimum power studies for benefits attributable to Duncan and Arrow is computed below. There is a 2.5 aMW adjustment to the 2000-01 Energy Entitlement according to item 7 of the "Columbia River Treaty Entity Agreement on the 1998/99, 1999/00, and 2000/2001 Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 5 April 1995.

a) Energy Entitlement Returned
Average Annual Usable Energy =
(508.4-2.5) aMW * (8.5 Maf/15.5 Maf) = 277.4 aMW
(508.4 -2.5) aMW * (10.48 km^3 /19.12 km^3)= 277.4 aMW

b) Capacity Entitlement Returned
Dependable Capacity =
1447.3 MW * (8.5 Maf/15.5 Maf) = 793.7 MW
1447.3 MW * (10.48 km^3/19.12 km^3) = 793.7 MW

6. Summary of Canadian Entitlement Computations

The following tables and chart summarize the study results.

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

This table shows the loads and resources used in the Step I studies and the computation of the coordinated hydro firm load for the Step I hydroregulation study. This table follows the definition of Step I loads and resources as defined by Treaty Annex B, paragraph 7, and clarified by the 1988 Entity Agreements. 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 Pacific Northwest Area (PNWA). The computation of Step I thermal installations is shown in Table 1A.

Table 3. Determination of Loads for 2000-01 Step II and Step 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 PNWA load. The PNWA firm loads on this table were based on the BPA 1994 Whitebook 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 2000-01 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 shown in Tables 1 and 3.

Table 5. Computation of Canadian Entitlement for 2000-01 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 0.5 Million Acre-Feet ($0.62\ km^3$) 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 6. Comparison of Recent DDPB Studies

Chart 1. Duration Curves of 30 Years Monthly Hydro Generation:

This chart shows duration curves of the hydro generation from the Step II and III studies, which graphically illustrates the change in average annual usable energy. Usable energy is firm energy plus usable secondary energy. Secondary energy is the energy capability each month that 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 that were used to meet PNWA 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 secondary energy remaining after thermal displacement.

7. Summary of Changes from Previous Year

Data from the five most recent DDPB's are summarized in Table 6. Firm energy shifting was not included in any of these operating plan studies. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Non-Hydro Resources

Loads for the 2000-01 AOP were based on the 1994 Whitebook medium case forecast developed by BPA in September 1994. Compared to the previous AOP, the PNWA firm energy load increased by 290 aMW. The total exports, not including firm surplus energy, decreased by 136 aMW. The decrease in exports is mainly due to the decreased Canadian Entitlement Return. It was assumed that 1/3 of the Entitlement Return was used to meet load in the PNWA, with the remaining amount assumed to be used in B.C. or California. The surplus firm energy increased by 32 aMW and was shaped to meet load over the year as 471 aMW 1 August through 30 April, and 1537 aMW in May through July.

The estimated increase in the Step I load due to the Canadian Entitlement Return exported to Canada assumed in the studies, and the computed Canadian Entitlement Return attributed to Duncan and Arrow for the period 1 August 2000 through 31 July 2001, are shown below for the Joint Optimum studies:

	Energy Entitlement Returned (aMW)		**Capacity Returned (MW)**	
	Estimated	Computed	Estimated	Computed
1 August 2000 to 31 July 2001	306.8	277.4	700.1	793.7

Iterative studies to correct the load estimate were not performed because updating the Canadian Entitlement Return estimates would not significantly affect the results of the studies.

The total annual energy capability of the thermal installations increased by 500 aMW. Major thermal resource changes included:

- Decrease of 10 aMW due to the termination of two Small Thermal projects: EWEB's Willamette Steam Plant and Puget's Shuffleton;
- Combustion Turbine resource increases of 285 aMW due to the addition of Clark County's new Cogentrix and Washington Water Power's Rathdrum now reporting energy;

- Cogeneration increased 99 aMW due to an increase in PP&L miscellaneous cogeneration and facilities upgrade at PGE's Coyote Springs;

- Centralia (large thermal generation) increased by 58 aMW;

- Thermal Non-Utility Generation (NUG) decreased by 20 aMW mostly due to the termination of Idaho's NUG's; and

- Imports increased by 87 aMW due to the addition of five new BPA imports and to the Glendale to PGE Seasonal Exchange. PG&E-to-WWP was the only import to terminate. Both the PP&L (WYM) to PP&L and Montana Thermal Import increased and showed different monthly shaping from the previous year's data.

(b) Operating Procedures

The 1990 level modified base flows with Grand Coulee pumping adjustments and return flows were again used. There were no additional depletions for the 2001 level, based on the recommendation of the Columbia River Water Management Group.

The Entities completed Step II and Step III Refill Studies and incorporated the resulting Power Discharge Requirements (PDR's) in the 2000-01 DDPB. New Limiting Rule Curves (LRC's) were developed for the Step II system based on 1937 water conditions. These studies are consistent with PNCA procedures, which include starting the system full 1 August 1936 and increasing the August through December load until the system just empties on 30 April 1937. The end--of-period contents in January, February, March, and 15 April are the LRC's for all major reservoir projects. Since the Step III study itself is a "LRC type" study, the LRC's are simply the end storages from the study.

Plant data for Arrow, Ice Harbor, Rock Island, and Chief Joseph were revised. However, Arrow, and Rock Island were the only projects to show a significant change in generation. Arrow had generation for the first time, and the Rock Island generation decreased due to updated information on turbine/generation efficiency.

Notable changes in non-power constraints include a revision of last year's spill data, and fisheries requirements (see Appendixes A1 and A2).

The spill and bypass assumptions for the 2000-01 DDPB studies are different from the 1999-00 DDPB studies, for operating year 2000-01 as follows:

- Fish bypass installations previously forecast to be installed at Bonneville, The Dalles, John Day, Ice Harbor, Wanapum, Rock Island, and Rocky Reach in the 1999-00 DDBP studies were removed from the hydroregulation model; and

- The Entities' 5 April 1995 agreement required the removal of the proportional fish spill and the bypass facilities from the studies, and in return the U.S. Entity would deliver the Entitlement Energy as calculated less 2.5 aMW. Most projects showed a decrease in generation. The only fish spill remaining was fixed fish spill at Wells and Rock Island. Ice Harbor and The Dalles had increased other spill. Priest Rapids was the only project to show increased generation because in the prior study bypass facilities were assumed to be installed and fish spill was modeled.

(c) Step III Critical Streamflow Period

The Step III study critical streamflow period was determined using the results of the Draft for Power method. This resulted in a 7-month critical period, 1 October 1936 through 30 April 1937 with 36 MW surplus in October 1937. If the Discretionary Draft method had been used the critical period would be 6 months, 1 November 1936 through 30 April 1937.

(d) Downstream Power Benefits Computation

The Capacity Entitlement decreased from 1461.9 MW in the 1999-00 DDPB to 1447.3 MW in the 2000-01 DDPB for a reduction of 14.6 MW. This was a result of a larger decrease in the Step II average critical period generation than in the Step III study. The 47.5 aMW decrease in the Step II critical period average generation was caused by increased spill, a plant data change at Rock Island, and the operation of Grand Coulee to the March ARC of empty in the second year of the critical period.

The Step III average critical period generation decreased by 19.2 MW compared to the 1999-00 DDPB due to increased spill, the Rock Island plant data change, and the start of the Step III critical stream flow period changed from November to October. Therefore, the difference between the Step II and Step III average critical period generation decreased by 28.3 aMW resulting in a decrease in the Capacity Entitlement.

The Canadian Energy Entitlement decreased from 559.5 aMW in the 1999-00 DDPB to 508.4 aMW in the 2000-01 DDPB, a decrease of 51.1 aMW. The following parameters were identified as having the most significant impact. Each value shown is a rough **estimate** of the incremental impact on the Energy Entitlement based on the AOP01 Step II and III studies with the AOP00 data for that parameter. Analysis of combinations of these parameters would likely produce different estimates of incremental impacts because the parameters are interrelated. For example, updated PDR's are required due to changes in other parameters, especially load shape.

Energy Entitlement

Parameter	(aMW)
Thermal Displacement Market Impact	-26
Load Shape Impact	- 8
Plant data & Spill Updates	- 7
Step II Coulee 6(c)(2)(C)	- 1
Coulee Adjusted Operating Rule Curves (ORC's)	+ 5
Updated Flood Control	+ 2
Combination of above effect on ORC's	-13
Re-operation of Canadian Storage	- 3
Total	-51

Thermal Displacement Market
The thermal displacement market increased approximately 690 aMW in the AOP01 compared to the AOP00. Major changes include an increase in thermal installations of 500 aMW, a decrease in minimum generation of 210 aMW, and an increase of approximately 20 aMW in the total system sales.

Load Shape
The change in annual energy load shape of the PNWA also caused a decrease in the Energy Entitlement. When compared to the AOP00, the Annual Energy Load Shape Percent for the Step I AOP01 increased August through October, decreased November through April, and increased May through July (See Table 3). Examination of this data for the four previous AOP's indicated that the load in the November through March period generally increased more rapidly than in other months.

Since the Step II system has a multi-year critical period, the change in load shape had virtually no impact on the study results. In the Step III system, the change in load shape and change in thermal installation caused the annual firm hydro energy to increase approximately 120 aMW. The load shape showed increases from April to October, but decreases or small changes from November to March. A flatter load shape combined with the concurrent changes in the secondary produced in the Step III long-term study (30-year) caused the Energy Entitlement to decrease approximately 8 aMW.

Plant Data & Spill Requirements
The Step II and III system annual average usable energy lost 30 aMW and 22 aMW, respectively; in generation due to updated information on turbine/generation efficiency curves (H/K data) at Rock Island. Other changes occurred due to removal of proportional spill and deferment of fish bypass facilities. The lost energy capability caused a decrease in the Energy Entitlement of approximately 4 aMW due to the Rock Island change and a decrease of 3 aMW due to spill changes and bypass dates.

Step II Grand Coulee 6(c)(2)(C)
Consistent with the PNCA 6(c)(2)(C) in the second year of the Step II critical period, Grand Coulee was drafted to its March ARC of empty, as other projects had reached or were below their March ARC's.

Grand Coulee ORC
The Inchelium ferry constraint at Grand Coulee limited draft below 289.1 thousand second-foot-days (ksfd) (707.3 cubic hectometers (hm^3)) (1220 feet) (371.86 meters) except to meet firm load. This required modifications to the ORC that increased the Energy Entitlement approximately 5 aMW.

Updated Flood Control
The Corps of Engineers submitted flood control in February 1995 which reflected flood control storage of 4.08 Maf (5.03 km^3) at Mica and 3.6 Maf (4.44 km^3) at Arrow. The Canadian Entity requested an exchange of flood control between Mica and Arrow which was used in previous AOP's. This split is based on flood control storage of 2.08 Maf (2.57 km^3) at Mica and 5.1 Maf (6.29 km^3) at Arrow. In July 1996 the Corps of Engineers provided new flood control reflecting the 2.08/5.1 Maf (2.57/6.29 km^3) split between Mica and Arrow. This flood control was used in the final AOP study.

Other changes include a new storage reservation diagram at Hungry Horse, dated 19 December 1995, which incorporated winter flood control in October and November. At Libby, there was some slight change in the percentage of refill during April and May. At Grand Coulee the flood control is dependent on available upstream storage and reflects the changes to other projects upstream. This change at Grand Coulee, along with some minor adjustments to the percentage of refill in April through June, describes the differences from the previous flood control used.

Effect on Determination of ORC's
Refill Studies were completed for the Step I, II, and III Studies to determine the ORC's. PDR's and LRC's change from year-to-year mainly due to changes in load shape, thermal resource generation shape, nonpower requirements including flood control, and irrigation depletions.

The Step II study PDR's were generally lower for the Variable Refill Curves (VRC's), but higher for the Assured Refill Curves (ARC's) when compared to the previous year's results. The ARC's generally controlled the computation of the ORC's and, since ORC's were higher, the projects were held higher longer throughout the year. More water was available to refill sooner, resulting in less ability to store, and increased spill. The Grand Coulee VRC was much lower in January through March, but higher in April. There were small changes at Horse, Duncan, Arrow, and Mica VRC's.

There was very little change from the previous year's PDR results in the Step III study. With only Base System storage available, the Step III system is difficult to refill and Hungry Horse was often on minimum flow due to requirements at Columbia Falls. The Grand Coulee VECC showed a significant change in March through April because of the 1220-ft (371.86 m) limit. There were minor changes to Chelan and Hungry Horse VECC's.

Re-operation for Joint Optimum

A comparison of the Canadian Entitlement for the Joint Optimum with the Canadian Entitlement for the U.S. Optimum showed an increase of 0.7 aMW of energy, and no change in the dependable capacity.

TABLE 1A
2000-01 ASSURED OPERATING PLAN
DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES (aMW)1/

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July	Annual Average	CP Ave 2/ (42 Mon)
1. Pacific Northwest Area (PNWA) Load	19741	19663	19199	19894	21871	23492	24161	23089	21701	20470	20567	19943	19829	19992	21107.8	21228.4
a) Annual Load Shape in Percent	93.52	93.15	90.96	94.25	103.61	111.30	114.47	109.38	102.81	96.98	97.44	94.48	93.94	94.71	100.0	100.6
2. Flows-Out of firm power from PNWA																
a) Firm Exports 3/	1268	1268	1285	990	959	959	933	908	946	948	984	968	1315	1301	1067.1	1058.3
b) Exclude Plant Sales	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2	-95.3
c) Firm Surplus	471	471	471	471	471	471	471	471	471	471	471	1537	1537	1537	739.7	701.4
d) ...Total	1637	1637	1654	1359	1328	1328	1302	1277	1315	1317	1353	2465	2781	2736	1712.6	1664.4
3. Load served by Flows-In of firm power except Step I thermal installations																
a) Non-thermal firm imports	-20	-20	-15	-21	-36	-47	-60	-69	-61	-29	-29	-28	-38	-26	-37.3	-37.8
b) Seasonal Exchange Imports	0	0	0	0	-280	-286	-286	-286	-30	-6	-6	0	0	0	-96.6	-109.8
c) ...Total	-20	-20	-15	-21	-316	-333	-346	-355	-91	-35	-35	-28	-38	-26	-133.9	-147.6
4. Load served by non-Step I resources located within the PNWA																
a) Hydro Independents (1929 water)	-1265	-1205	-1070	-1134	-1157	-1051	-1092	-818	-962	-1274	-1331	-1794	-1604	-1282	-1210.7	-1063.3
b) Non-Step I Coordinated Hydro (1929 water)	-544	-475	-576	-966	-964	-1074	-1215	-690	-772	-760	-728	-656	-1084	-589	-820.8	-854.8
c) Non-Thermal PURPA/NUGS	-175	-175	-164	-156	-154	-150	-148	-152	-156	-172	-171	-179	-171	-178	-162.9	-161.6
d) Miscellaneous Resources	-38	-38	-41	-45	-51	-55	-55	-52	-50	-48	-48	-45	-44	-39	-46.9	-47.3
e) ...Total (1929 water)	-2022	-1893	-1851	-2301	-2326	-2331	-2510	-1712	-1940	-2254	-2277	-2674	-2903	-2088	-2241.3	-2127.1
5. Total Step I System Firm Loads (1929 water)	19336	19386	18987	18930	20556	22157	22607	22299	20985	19498	19607	19707	19669	20614	20445.2	20618.0
6. Step I Thermal Installations																
a) Large Thermal (includes plant sales)	4615	4615	4615	4615	4615	4615	4615	4615	4428	4081	3364	2111	3969	4615	4260.0	4310.6
b) Small Thermal	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34.4	34.4
c) Combustion Turbines	2173	2089	2070	2310	2268	2310	2310	2310	2310	1853	1141	1607	1855	2212	2099.5	2122.9
d) Cogeneration (includes plant sales)	1584	1584	1574	1576	1578	1580	1581	1580	1580	1590	1499	967	1528	1584	1520.4	1528.6
e) Thermal PURPA/NUGS	263	263	247	234	230	226	222	228	233	258	257	268	256	267	244.4	242.4
f) Thermal classified as Renewables	51	51	51	51	51	51	51	51	51	51	51	51	51	51	50.7	50.7
g) Thermal Firm Imports	1251	1230	988	1142	1749	1967	1912	1794	1451	1176	1079	1037	1221	1318	1410.7	1436.6
h) Exclude Seas Exch Imports (see 3b) 4/	0	0	0	0	-280	-286	-286	-286	-30	-6	-6	0	0	0	-96.6	-109.8
i) Exclude Plant Sales (see 2b) 5/	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2	-95.3
j) ...Total	9869	9764	9477	9860	10143	10395	10338	10224	9956	8934	7317	6035	8844	9979	9429.2	9521.1
7. Total Step I Hydro Load (1929 water) 6/	9467	9623	9510	9070	10413	11762	12269	12075	11029	10564	12290	13671	10825	10635	11015.9	11096.9
a) Hydro Maintenance as a load	32	27	9	9	4	0	0	0	5	7	8	20	16	51	12.7	11.4
b) Coordinated Hydro Model Load (1929 water) 7/	10043	10125	10095	10046	11381	12836	13484	12765	11807	11332	13025	14347	11925	11275	11849.4	11963.0

1/ Step I Loads and Resources for the U.S. Optimum Study (01-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Total regional firm load plus pumping.

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

3/ Includes 205 aMW uniform export of Canadian Entitlement. 1/3 is returned to Canada, 1/3 exported to SW, and 1/3 remained in the region.

4/ The Seasonal Exchange Imports are included in Thermal Firm Imports, line 6(g).

5/ Plant sales include Longview Fibre (Cogeneration, line 6(d)) and 15 percent of Boardman (Large Thermal, line 6(a)).

6/ Regulated hydro load for U.S. projects located upstream of Bonneville Dam, line 5 minus line 6(j).

7/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintenance plus Non-Step I Coordinated Hydro.

TABLE 1B
2000-01 ASSURED OPERATING PLAN
DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES (MW) 1/

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. Pacific Northwest Area (PNWA) Load	24768	24723	24548	27308	29515	32066	33021	32018	29654	28080	28162	26369	25390	24984
a) Annual Load Shape in Percent	79.54	79.54	78.21	72.85	74.10	73.26	73.17	72.11	73.18	72.86	72.86	75.63	78.10	80.02
2. Flows-Out of firm power from PNWA														
a) Firm Exports 2/	2933	2933	2936	2329	1419	1407	1407	1483	1458	1450	1500	1729	2960	2983
b) Exclude Plant Sales	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-45	-116	-116
c) Firm Surplus	592	592	602	647	636	643	644	653	644	646	646	2032	1968	1921
d) ...Total	3409	3409	3422	2859	1938	1934	1934	2020	1985	1980	2030	3716	4812	4788
3. Load served by Flows-In of firm power except Step I thermal installations														
a) Non-thermal firm imports	-147	-147	-147	-147	-134	-148	-170	-194	-224	-147	-147	-147	-147	-147
b) Exclude Seasonal Exch Imports	0	0	0	0	-601	-601	-601	-601	-46	-12	-12	0	0	0
c) ...Total	-147	-147	-147	-147	-735	-749	-771	-795	-270	-159	-159	-147	-147	-147
4. Loads served by non-Step I resources located withinin the PNWA														
a) Hydro Independents (1937 water)	-1932	-1917	-1845	-1797	-1731	-1701	-1641	-1766	-1852	-1976	-2000	-2176	-2202	-2038
b) Non-Step I Coordinated Hydro (1937 water)	-2597	-2592	-2656	-2607	-2507	-2426	-2307	-2182	-2076	-1952	-2100	-2009	-2418	-2491
c) Non-Thermal PURPA/NUGS	-168	-168	-159	-151	-147	-143	-142	-145	-151	-165	-165	-172	-163	-171
d) Miscellaneous Resources	-38	-38	-41	-45	-351	-355	-355	-352	-350	-48	-48	-45	-44	-39
e) ...Total (1937 water)	-4735	-4715	-4700	-4600	-4735	-4624	-4445	-4445	-4429	-4140	-4313	-4403	-4827	-4739
5. Total Step I System Firm Loads (1937 water)	23296	23271	23123	25421	25983	28626	29739	28798	26941	25761	25721	25536	25229	24886
6. Step I Thermal Installations														
a) Large Thermal (includes plant sales)	5286	5286	5286	5286	5286	5286	5286	5286	5021	4809	3813	2528	4270	5286
b) Small Thermal	40	40	40	40	43	43	43	43	40	40	40	40	40	40
c) Combustion Turbines	2511	2333	2449	2750	2759	2764	2767	2762	2756	1895	1856	2345	2274	2518
d) Cogeneration (includes plant sales)	1650	1650	1639	1642	1644	1646	1647	1646	1646	1656	1656	1107	1261	1650
e) Thermal PURPA/NUGS	253	253	239	226	221	215	213	218	226	248	248	258	245	256
f) Thermal classified as Renewables	52	52	52	52	52	52	52	52	52	52	52	52	52	52
g) Thermal Firm Imports	1547	1550	1208	1479	2051	2277	2229	2185	1631	1291	1280	1680	1659	1546
h) Exclude Seas Exch Imports (see 3b) 3/	0	0	0	0	-601	-601	-601	-601	-46	-12	-12	0	0	0
i) Exclude Plant Sales (see 2b) 4/	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-45	-116	-116
j) ...Total	11223	11048	10798	11359	11339	11566	11520	11475	11210	9863	8817	7965	9685	11232
7. Total Step I Hydro Load (1937 water) 5/	12073	12223	12325	14062	14644	17061	18219	17323	15731	15898	16904	17571	15544	13655
a) Hydro Maintenance as a load	4629	4066	3787	3208	2935	2037	1561	2295	2646	2751	2483	2360	2204	3725
b) Coordinated Hydro Model Load (1937 water) 6/	19299	18882	18768	19877	20085	21524	22088	21800	20452	20601	21487	21940	20166	19870

1/ Step I Loads and Resources for the U.S. Optimum study (01-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Total regional firm load plus pumping.

2/ Includes 467 aMW uniform export of Canadian Entitlement. 1/3 is returned to Canada, 1/3 exported to SW, and 1/3 remained in the region.

3/ The Seasonal Exchange Imports are included in Thermal Firm Imports, line 6(g).

4/ Plant sales include Longview Fibre (Cogeneration, line 6(d)) and 15 percent of Boardman (Large Thermal, line 6(a)).

5/ Regulated hydro load for U.S. projects located upstream of Bonneville Dam, line 5 minus line 6(j).

6/ The Coordinated Hydro Model Load is the Step I System Hydro Load plus Hydro Maintenance plus Non-Step I Coordinated Hydro.

TABLE 2
2000-01 ASSURED OPERATING PLAN
DETERMINATION OF THERMAL DISPLACEMENT MARKET
(Energy in aMW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	June	July	Annual Average	CP Ave (42 Mon)
1. STEP I THERMAL INSTALLATIONS																
a) From Table 1A, line 6(j)	9869	9764	9477	9860	10143	10395	10338	10224	9956	8934	7317	6035	8844	9979	9429.2	9521.1
2. MINIMUM THERMAL GENERATION																
a) Large Thermal Min. Generation	147	147	456	456	456	456	456	456	456	147	147	147	147	147	326.5	344.9
b) Cogen & Small Thermal Min. Gen	444	444	446	449	451	452	452	451	451	450	450	214	446	444	428.8	431.8
c) NUGS Thermal Min. Generation	88	88	82	78	77	75	74	76	78	86	86	89	85	89	81.5	80.8
d) ...Total Minimum Generation	679	679	984	983	984	983	982	983	985	683	683	450	678	680	836.7	857.6
3. DISPLACEABLE THERMAL RESOURCES	9190	9085	8492	8877	9159	9412	9356	9242	8971	8251	6634	5585	8165	9299	8592.5	8663.6
4. SYSTEM SALES																
a) Total Exports	1268	1268	1285	990	959	959	933	908	946	948	984	968	1315	1301	1067.1	1058.3
b) Exclude Can Entitlement (out of the PNWA)	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-204.5	-204.5
c) Exclude Plant Sales Exports	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2	-95.3
d) Exclude Seasonal Exchange Exports	-272	-272	-283	-15	0	0	0	0	0	0	0	0	-283	-283	-94.8	-88.3
e) Firm Surplus Sales	471	471	471	471	471	471	471	471	471	471	471	1537	1537	1537	739.7	701.4
f) ...Total System Sales	1160	1160	1167	1139	1123	1124	1097	1073	1110	1113	1148	2261	2294	2249	1413.3	1371.6
g) Uniform Average Annual System Sales	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413.3	1413.3
5. THERMAL DISPLACEMENT MARKET	7777	7672	7079	7464	7746	7999	7942	7828	7558	6838	5221	4172	6752	7886	7179.3	7250.3

Notes:

Line 2a	Large Thermal minimum generation includes Centralia and Jim Bridger.
Line 2b	Cogen & Small Thermal Minimum Generation Includes Spokane Muni Solid Waste, Tacoma Steam Plant , Vale, and PP&L cogen plants.
Line 2c	60% of the total NUGS is thermal. Non-displaceable NUGS generation is 1/3 of the thermal NUGS.
Line 2d	Total Minimum Thermal Generation, the sum of lines 2(a) through line 2(c).
Line 3	Step I Thermal Installations that are displaceable, line 1(a) minus line 2(d).
Line 4a	Total Exports from Table 1A, line 2(a).
Line 4c	Plant sales consist of Longview Fibre and 15 percent of Boardman.
Line 4d	Seasonal exchanges are with extraregional utilities.
Line 4f	System Sales are total exports excluding plant sales, seasonal exchanges, and the Canadian Entitlement. The sum of lines 4(a) through line 4(e).
Line 4g	Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.
Line 5	PNWA Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNWA firm loads, line 3 minus line 4(g).

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TABLE 3
2000-01 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR STEP II AND STEP III STUDIES

PACIFIC NORTHWEST AREA (PNWA) LOAD						STEP II STUDY		STEP III STUDY		
Period	PNWA 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
August 1-15	19741	93.52	24768	79.54	9869	17204.5	7335.7	14935.6	5066.8	August 1-15
August 16-31	19663	93.15	24723	79.54	9764	17136.6	7372.7	14876.6	5112.8	August 16-31
September	19199	90.96	24548	78.21	9477	16732.2	7255.5	14525.6	5048.9	September
October	19894	94.25	27308	72.85	9860	17337.7	7477.9	15051.2	5191.4	October
November	21871	103.61	29515	74.10	10143	19060.8	8917.6	16547.1	6403.9	November
December	23492	111.30	32066	73.26	10395	20474.0	10078.9	17773.9	7378.9	December
January	24161	114.47	33021	73.17	10338	21057.0	10719.4	18280.1	7942.4	January
February	23089	109.38	32018	72.11	10224	20122.3	9897.8	17468.6	7244.1	February
March	21701	102.81	29654	73.18	9956	18912.7	8956.6	16418.5	6462.4	March
April 1-15	20470	96.98	28080	72.86	8934	17840.1	8906.0	15487.4	6553.3	April 1-15
April 16-30	20567	97.44	28162	72.86	7317	17924.4	10607.4	15560.6	8243.6	April 16-30
May	19943	94.48	26369	75.63	6035	17380.6	11345.1	15088.5	9053.0	May
June	19829	93.94	25390	78.10	8844	17281.7	8437.9	15002.6	6158.9	June
July	19992	94.71	24984	80.02	9979	17423.3	7444.2	15125.5	5146.5	July
Annual Average 7/	21107.8	100.00		75.27	9429.2	18396.0	8966.7	15969.9	6540.7	Annual Average
SI CP Average (42)	21228.4			75.08	9521.1	18617.7	9032.9	16719.3	6854.4	CP avg (7 mo)
SII CP Average (20)	21362.2				9584.8					
SIII CP Average (7)	22098.2				9864.9					
						Input 5/ →	9032.9	Input 6/ →	6854.4	
August 1-31	19700.4	93.3	24768.2	79.54	9814.6	17169.4	7354.8	14905.2	5090.5	August 1-31
April 1-30	20518.4	97.2	28161.9	72.86	8125.6	17882.3	9756.7	15524.0	7398.4	April 1-30

1/ The PNWA 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 6(j)).
3/ The total firm load for the Step II/III studies is computed to have the same shape as the load of the PNWA.
4/ The hydro load is equal to the total load minus the Step I study thermal installations.
5/ Input is the assumed critical period (CP) average generation for the Step II hydro studies and is used to calculate the residual hydro loads.
6/ Input is the assumed Step III 7-month CP average generation: Input = 6854.4 MW excludes a 36 MW surplus in October (7-month CP average = 5.3 MW) which cannot be shaped to meet the firm loads.
7/ The Annual Average is for 2000-01 operating year, not a leap year.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2000-01 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA: NUMBER OF UNITS	BASIC DATA: MAXIMUM INSTALLED PEAKING CAPACITY MW	STEP I: USABLE STORAGE ksf	STEP I: JANUARY 1937 PEAKING CAP. MW	STEP I: CRITICAL PERIOD AVERAGE GEN. MW	STEP II: USABLE STORAGE ksf	STEP II: JANUARY 1945 PEAKING CAP. MW	STEP II: CRITICAL PERIOD AVERAGE GEN. MW	STEP II: 30 YEAR AVERAGE ANNUAL GEN. MW	STEP III 1/: USABLE STORAGE ksf	STEP III 1/: JANUARY 1937 PEAKING CAP. MW	STEP III 1/: CRITICAL PERIOD AVERAGE GEN. MW	STEP III 1/: 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	359	104	3008	224	119	107	3008	344	178	106
Kerr	3	160	1219	154	114	1219	152	111	118	1219	150	126	120
Thompson Falls	6	85	0	85	54	0	85	53	57	0	85	59	57
Noxon Rapids	5	554	231	511	149	0	554	134	201	0	554	154	202
Cabinet Gorge	4	239	0	239	99	0	239	89	116	0	239	102	117
Albeni Falls	3	49	1155	22	22	1155	20	23	21	1155	20	18	21
Box Canyon	4	74	0	71	45	0	71	45	47	0	70	52	47
Grand Coulee	24+3SS	6684	5185	5911	1945	5072	6335	1763	2297	5072	5701	1171	2251
Chief Joseph	27	2614	0	2614	1118	0	2614	1017	1362	0	2614	717	1288
Wells	10	840	0	840	410	0	840	381	476	0	840	277	436
Chelan	2	54	677	51	38	676	51	36	45	676	51	44	43
Rocky Reach	11	1267	0	1267	576	0	1267	534	692	0	1267	376	648
Rock Island	18	523	0	494	254	0	494	238	299	0	494	171	278
Wanapum	10	986	0	986	518	0	986	482	600	0	986	330	542
Priest Rapids	10	912	0	912	510	0	912	477	572	0	912	337	513
Brownlee	5	675	975	675	240	974	675	314	316	974	675	267	316
Oxbow	4	220	0	220	99	0	220	124	128	0	220	116	128
Ice Harbor	6	693	0	693	213	0	693	233	304	0	693	179	304
McNary	14	1127	0	1127	691	0	1127	637	801	0	1127	482	747
John Day	16	2484	535	2484	891	0	2484	921	1252	0	2484	689	1216
The Dalles	22+2F	2074	0	2074	740	0	2074	724	983	0	2074	564	963
Bonneville	18+2F	1147	0	1147	594	0	1147	579	728	0	1147	450	692
Kootenay Lake	0	0	673	0	0	673	0	0	0	673	0	0	0
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	223	0	0	0
Total Base and Canadian System Hydro 2/		23889	29445	22936	9426	28500	23263	9033	11522	13000	22747	6860	11035
ADDITIONAL STEP I PROJECTS													
Libby	5	600	4980	549	194								
Boundary	6	1055	0	855	369								
Spokane River Plants	24	173	104	166	100								
Hells Canyon	3	450	0	410	193	NOT APPLICABLE TO STEP II & III							
Dworshak	3	450	2015	445	152								
Lower Granite	6	932	0	930	182								
Little Goose	6	932	0	928	181								
Lower Monumental	6	932	0	922	185								
Pelton, Rereg., & RB	7	423	274	418	126								
Total added Step 1		5947	7373	5624	1682								
THERMAL INSTALLATION 3/				11520	9521		11520	9585			11520	9865	
RESERVES, HYDRO MAINTENANCE 4/				-4203	-11		-2302	0			-1999	0	
TOTAL RESOURCES				35877	20618		32481	18618			32268	16725	
STEP I, II, & III LOADS 5/				29739	20618		28779	18618			24983	16719	
SURPLUS				6138	0		3702	0			7285	5	
CRITICAL PERIOD	Starts		September 1, 1928			September 1, 1943				October 1, 1936			
	Ends		February 29, 1932			April 30, 1945				April 30, 1937			
	Length (Months)		42 Months			20 Months				7 Months			
	Study Identification		01-41			01-42				01-13			

1/ Step III 7-month critical period average generation: Input = 6854.4 MW includes a 36 MW surplus in October (7-month critical period average = 5.3 MW) which cannot be shaped to meet the firm loads.

2/ The above totals are correct, but may not equal the sum of the above values due to rounding.

3/ From Tables 1 and 3.

4/ Peak reserves for Step I, II, III are 8 percent of January peak load from Table 3. Energy reserve deductions only include the hydro maintenance for Step I study (reserves have been included in thermal plant energy capability) from Table 1A, line 7(a).

5/ Step I energy load from Table 1A, line 5 and January peak load fromTable 1B, line 5. Step II & III energy load from Table 3. Step II & III peak load is equal to the step II or step III annual average load multiplied by the ratio of the PNWA January peak load to the PNW annual average load.

TABLE 4M
(Metric Units)
SUMMARY OF POWER REGULATIONS
FROM 2000-01 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA		STEP I			STEP II				STEP III 1/			
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE hm³	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE hm³	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE hm³	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES													
CANADIAN													
Mica			8635			8635							
Arrow			8758			8758							
Duncan			1727			1727							
Subtotal			19119			19119							
BASE SYSTEM													
Hungry Horse	4	428	3789	359	104	3710	224	119	107	3710	344	178	106
Kerr	3	160	1504	154	114	1504	152	111	118	1504	150	126	120
Thompson Falls	6	85	0	85	54	0	85	53	57	0	85	59	57
Noxon Rapids	5	554	285	511	149	0	554	134	201	0	554	154	202
Cabinet Gorge	4	239	0	239	99	0	239	89	116	0	239	102	117
Albeni Falls	3	49	1425	22	22	1425	20	23	21	1425	20	18	21
Box Canyon	4	74	0	71	45	0	71	45	47	0	70	52	47
Grand Coulee	24+3SS	6684	6396	5911	1945	6256	6335	1763	2297	6256	5701	1171	2251
Chief Joseph	27	2614	0	2614	1118	0	2614	1017	1362	0	2614	717	1288
Wells	10	840	0	840	410	0	840	381	476	0	840	277	436
Chelan	2	54	835	51	38	834	51	36	45	834	51	44	43
Rocky Reach	11	1267	0	1267	576	0	1267	534	692	0	1267	376	648
Rock Island	18	523	0	494	254	0	494	238	299	0	494	171	278
Wanapum	10	986	0	986	518	0	986	482	600	0	986	330	542
Priest Rapids	10	912	0	912	510	0	912	477	572	0	912	337	513
Brownlee	5	675	1203	675	240	1201	675	314	316	1201	675	267	316
Oxbow	4	220	0	220	99	0	220	124	128	0	220	116	128
Ice Harbor	6	693	0	693	213	0	693	233	304	0	693	179	304
McNary	14	1127	0	1127	691	0	1127	637	801	0	1127	482	747
John Day	16	2484	660	2484	891	0	2484	921	1252	0	2484	689	1216
The Dalles	22+2F	2074	0	2074	740	0	2074	724	983	0	2074	564	963
Bonneville	18+2F	1147	0	1147	594	0	1147	579	728	0	1147	450	692
Kootenay Lake	0	0	830	0	0	830	0	0	0	830	0	0	0
Coeur d'Alene Lake	0	0	275	0	0	275	0	0	0	275	0	0	0
Total Base and Canadian System Hydro 2/		23889	36320	22936	9426	35155	23263	9033	11522	16036	22747	6860	11035
ADDITIONAL STEP I PROJECTS													
Libby	5	600	6143	549	194								
Boundary	6	1055	0	855	369								
Spokane River Plants	24	173	128	166	100								
Hells Canyon	3	450	0	410	193				NOT APPLICABLE TO STEP II & III				
Dworshak	3	450	2486	445	152								
Lower Granite	6	932	0	930	182								
Little Goose	6	932	0	928	181								
Lower Monumental	6	932	0	922	185								
Pelton, Rereg., & RB	7	423	338	418	126								
Total added Step 1		5947	9095	5624	1682								
THERMAL INSTALLATION 3/				11520	9521		11520	9585			11520	9865	
RESERVES, HYDRO MAINTENANCE 4/				-4203	-11		-2302	0			-1999	0	
TOTAL RESOURCES				35877	20618		32481	18618			32268	16725	
STEP I, II, & III LOADS 5/				29739	20618		28779	18618			24983	16719	
SURPLUS				6138	0		3702	0			7285	5	
CRITICAL PERIOD	Starts			September 1, 1928			September 1, 1943				October 1, 1936		
	Ends			February 29, 1932			April 30, 1945				April 30, 1937		
	Length (Months)			42 Months			20 Months				7 Months		
	Study Identification			01-41			01-42				01-13		

1/ Step III 7-month critical period average generation: Input = 6854.4 MW includes a 36 MW surplus in October (7-month critical period average = 5.3 MW) which cannot be shaped to meet the firm loads.

2/ The above totals are correct, but may not equal the sum of the above values due to rounding.

3/ From Tables 1 and 3.

4/ Peak reserves for Step I, II, III are 8 percent of January peak load from Table 3. Energy reserve deductions only include the hydro maintenance for Step I study (reserves have been included in thermal plant energy capability) from Table 1A, line 7(a).

5/ Step I energy load from Table 1A, line 5 and January peak load fromTable 1B, line 5. Step II & III energy load from Table 3. Step II & III peak load is equal to the step II or step III annual average load multiplied by the ratio of the PNWA January peak load to the PNW annual average load.

TABLE 5
(English & Metric Units)
COMPUTATION OF CANADIAN ENTITLEMENT FOR 2000-01 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 01-42)
B. Optimum Power Generation in the U.S. Only (From 01-12)
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km^3) Reduction in Total Canadian Treaty Storage (From 01-22)

	CAPACITY ENTITLEMENT		
Determination of Dependable Capacity Credited to Canadian Storage (MW)	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	9032.9	9032.9	9003.2
Step III - Critical Period Average Generation 2/	6859.6	6859.6	6859.6
Gain Due to Canadian Storage	2173.3	2173.3	2143.6
Average Critical Period Load Factor in percent 3/	75.08	75.08	75.08
Dependable Capacity Gain 4/	2894.5	2894.5	2855.0
Canadian Share of Dependable Capacity 5/	1447.3	1447.3	1427.5

	ENERGY ENTITLEMENT		
Determination of Increase in Average Annual Usable Energy (aMW)			
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8967.3	8967.3	8938.0
Thermal Displacement Energy 7/	2183.3	2180.7	2196.6
Other Usable Secondary Energy 8/	148.7	149.7	152.4
System Annual Average Usable Energy	11299.3	11297.7	11287.0
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6541.1	6541.1	6541.1
Thermal Displacement Energy 7/	3239.8	3239.8	3239.8
Other Usable Secondary Energy 8/	501.5	501.5	501.5
System Annual Average Usable Energy	10282.4	10282.4	10282.4
Average Annual Usable Energy Gain 9/	1016.9	1015.3	1004.6
Canadian Share of Average Annual Energy Gain 5/	508.4	507.7	502.3

1/ Step II values were obtained from the 01-42, 01-12, and 01-22 studies, respectively.
2/ Step III values were obtained from the 01-13 study and Table 3. Includes 36 aMW of surplus in October 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, which includes 7 leap years (29 days in February).
7/ Average 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
(English & Metric Units)
COMPARISON OF RECENT DDPB STUDIES

	1996-97	1997-98	1998-99	1999-00	2000-01
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	20324.6	20387.3	20479.6	20817.8	21107.8
Annual/January Load (%)	87.1	86.9	86.3	85.9	87.4
Critical Period (CP) Load Factor (%)	75.3	75.2	75.6	75.3	75.1
Annual Firm Exports	511.2	926.3	1075.3	1202.7	1067.1
Annual Firm Surplus (MW) 1/	610.5	433.2	534.6	708.1	739.7
THERMAL INSTALLATIONS (MW) 2/					
January Peak Capability	10381	10514	11003	11341	11520
CP Energy	7975	8141	8462	9019	9521
CP Minimum Generation	675	632	789	1071	858
Average Annual System Export Sales	887	1133	1265	1392	1413
Average Annual Displaceable Market	6104	6105	6345	6490	7179
HYDRO CAPACITY (MW)					
Total Installed	29785	29786	29786	29786	29836
Base System	23841	23856	23856	23856	23889
STEP I/II/III CP (MONTHS)	42/20/7	42/20/6	42/20/6.5	42/20/7	42/20/7
BASE STREAMFLOWS AT THE DALLES (cfs) 3/					
Step I 50-yr. Average Streamflow	179338	180748	181664	181664	181663
Step I CP Average	113053	114127	114496	114496	114496
Step II CP Average	100036	101008	101537	101525	101525
Step III CP Average	64756	64870	58483	64960	64959
BASE STREAMFLOWS AT THE DALLES (m^3/s) 3/					
Step I 50-yr. Average Streamflow	5078.28	5118.20	5144.15	5144.15	5144.12
Step I CP Average	3201.30	3231.71	3242.16	3242.16	3242.16
Step II CP Average	2832.70	2860.22	2875.20	2874.87	2874.85
Step III CP Average	1833.68	1836.92	1656.05	1839.47	1839.43
CAPACITY BENEFITS (MW)					
Step II CP Generation	8963.5	9018.0	9064.1	9080.4	9032.9
Step III CP Generation	6895.5	7169.4	6773.9	6878.8	6859.6
Step II Gain over Step III	2068.0	1848.6	2290.2	2201.7	2173.3
CANADIAN ENTITLEMENT	1373.4	1229.6	1514.7	1461.9	1447.3
Change due to Mica Reoperation	1.0	0.0	-0.4	0.2	0.0
Benefit in Sales Agreement	486.0	471.0	416.0	200.0	192.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm Hydro	8871.0	8963.0	9000.0	8990.3	8967.3
Step II Thermal Displacement	2037.4	2037.7	2101.3	2129.5	2183.3
Step II Other Usable Secondary	207.0	194.9	188.3	193.5	148.7
Step II System Annual Average Usable	11115.4	11195.6	11289.6	11313.3	11299.3
Step III Annual Firm Hydro	6445.0	6579.0	6502.1	6422.2	6541.1
Step III Thermal Displacement	2951.6	2902.9	3066.8	3182.0	3239.8
Step III Other Usable Secondary	623.7	607.2	595.3	590.1	501.5
Step III System Annual Average Usable	10020.3	10089.1	10164.2	10194.3	10282.4
CANADIAN ENTITLEMENT	547.5	553.3	562.7	559.5	508.4
Change due to Mica Reoperation	-0.9	-2.8	-4.1	-0.8	0.7
ENTITLEMENT in Sales Agreement	254.0	246.0	215.0	103.0	99.0
STEP II PEAK CAPABILITY (MW)	31472	31647	32074	32421	32481
STEP II PEAK LOAD (MW)	26252	26587	27317	28386	28779
STEP III PEAK CAPABILITY (MW)	31409	31456	31793	32206	32268
STEP III PEAK LOAD (MW)	22350	22859	23391	24318	24983

FOOTNOTES FOR TABLE 6

1. Average annual firm surplus is the additional shaped load including the surplus shaped in the following periods:

AOP Study	Amount Shaped (MW)	
1996-97	276	1-31August, January through 30 April, June, and July,
	516	September through December, and
	3276	May.
1997-98	3000	May and
	2171	June.
1998-99	3199	May and June.
1999-00	4237	May and June.
2000-01	471	1 August through 30 April,
	1537	May through July.

2. Thermal installations include thermal imports and all existing and planned thermal resources. Beginning with the 1996-97 AOP, thermal installations also included cogeneration, renewable thermal, thermal NUG/PURPA, minus seasonal exchange imports and plant sales.

3. The 1990 level modified flows were used and no additional irrigation depletions were anticipated for the 2000-01 level. There is, however, an adjustment for Grand Coulee pumping and return flow.

CHART 1
2000-01 DDPB STUDIES
DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)