EXHIBIT B: PROJECT OPERATIONS AND RESOURCE UTILIZATION

1 Contents and Purpose of this Exhibit

Exhibit B describes the operation of the Boundary Hydroelectric Project (Project), water availability and use, and production and use of Project generation under the existing Project license.

2 General Description of Boundary Project Operations

The Pend Oreille River system, which includes the Clark Fork River basin upstream of Lake Pend Oreille, is highly regulated, with flows controlled by dams associated with several energy production and/or storage projects (Figure B.2-1). Flows into Boundary Reservoir are influenced by the operations of upstream projects, including Box Canyon Dam (Pend Oreille County Public Utility District [PUD]), Albeni Falls Dam (U.S. Army Corps of Engineers), and other projects farther upstream, such as Hungry Horse Dam (U.S. Bureau of Reclamation). Boundary Reservoir has a small active storage capacity relative to average daily river flow, and as a result, instream flow releases to the Pend Oreille River from the Project on annual, seasonal, or monthly time intervals are influenced by projects upstream from the Project (SCL 2008). The Project has no control or influence over the upstream flow releases that it receives from upstream projects.

The Project is operated in a load-following mode that shapes available water to deliver power during peak-load hours with a total plant capability of approximately 1,040 megawatts (MW) from its six turbines (FERC 2007). This operating regime allows Seattle City Light (SCL) to meet continued service area load growth and support regional system reliability. The normal maximum reservoir water surface is at elevation 1,994 feet North American Vertical Datum (NAVD) 88 [1] at the forebay. The reservoir has relatively little active storage (40,843 acre-feet) within the maximum drawdown of 40 feet (active storage from elevation 1,994 NAVD 88 to elevation 1,954 NAVD 88 feet) authorized under the current license (SCL 2008).

The load-following mode of the Project primarily affects instream flow releases on a daily or hourly interval. Project operations affect hydrologic conditions in the Pend Oreille River upstream to Box Canyon Dam, as well as the Pend Oreille River downstream of the Project. Upstream effects are associated with water surface elevation fluctuations in the reservoir, and downstream effects are associated with flow release fluctuations from the Project to the Pend Oreille River/Seven Mile Reservoir.

[1] Elevation values are in datum NAVD 88 unless otherwise noted.

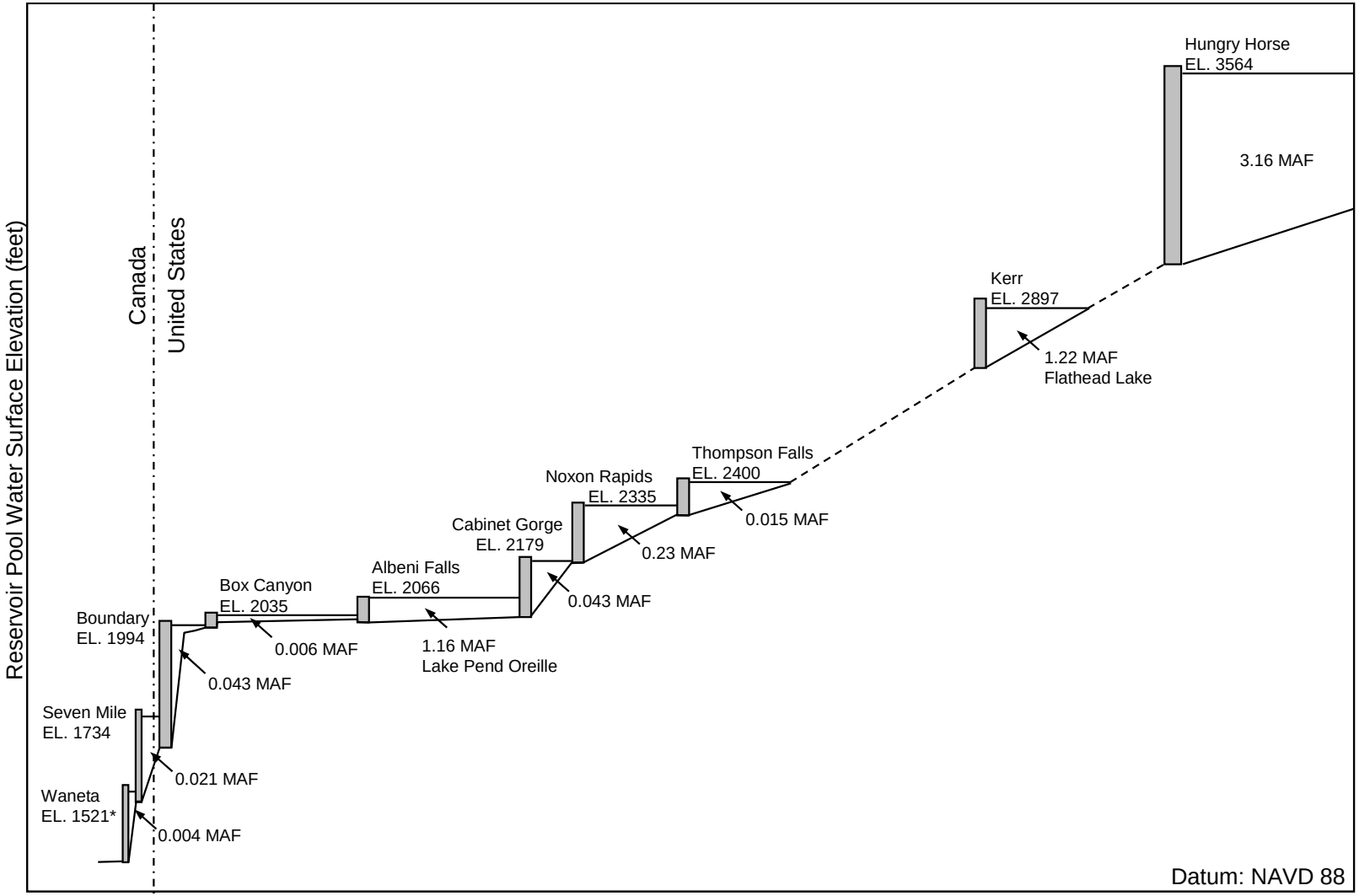

Figure B.2-1. Locations and usable storage volumes (million acre feet, MAF) of projects in the Pend Oreille River system from Hungry Horse (Montana) downriver to Waneta (Canada), near the confluence of the Columbia River. Horizontal and vertical axes are not to scale (Waneta Reservoir maximum operating level with respect to Canal Plan Agreement Operating Procedures).

During the summer recreation season, SCL voluntarily restricts and maintains the summer forebay pool to a water surface elevation above 1,984 feet, NAVD 88 from 6:00 am through 8:00 pm from Memorial Day weekend (starting Friday evening) through Labor Day weekend (on Monday evening) to facilitate reservoir access and related recreational activities during daytime hours. At night during the summer, from 8:00 pm to 6:00 am, the forebay water surface elevation is maintained above elevation 1,982 feet, NAVD 88. For the remainder of the year, the water surface may fluctuate between elevations 1,994 feet and 1,974 feet NAVD 88. Storage between elevation 1,974 feet NAVD 88 and elevation 1,954 feet NAVD 88 is reserved for extreme system load requirements. Flood storage is not provided, and other than the operating goals noted above there are no seasonal or minimum flow requirements.

2.1. Historic Flow Data

The total average inflow to Boundary Reservoir from 1987 to 2005 (the period of operation since the additions of Units 55 and 56) is estimated to be 24,100 cubic feet per second (cfs). Of this total, about 98.1 percent came from flows from Box Canyon Dam to the Pend Oreille River, 1.0 percent came from Sullivan Creek (the largest tributary to the Pend Oreille River between Box Canyon Dam and Boundary Dam), and 0.9 percent came from additional smaller tributaries (SCL 2008).

2.1.1. Project Flow Data

The average monthly and annual total inflows into and releases from Boundary Dam to the Pend Oreille River for the period 1987-2005 are summarized in Tables B.2-1 and B.2-2. Further detail about the methods used to derive the inflow and release values can be found in the *Compilation of Project Hydrologic Data: Preparation of Hydrologic Database and Hydrologic Statistics in Support of Relicensing Studies* (SCL 2008). Significant spills for the period of record are shown in Table B.2-3.

Downstream of Boundary Dam, the Pend Oreille River gains about 570 square miles of additional drainage area between Boundary Dam and Seven Mile Dam. Of this total, the Salmo River, with a drainage area of 475 square miles, accounts for 83 percent of the additional drainage area. The remainder comes from smaller tributaries. The total mean annual inflow to Seven Mile Reservoir is estimated to be 25,400 cfs. Of this total, releases from Boundary Dam to the Pend Oreille River account for 94.8 percent, the Salmo River accounts for 4.3 percent, and the additional downstream tributaries account for 0.9 percent.

Table B.2-1. Mean, minimum and maximum monthly and annual total flow release to Boundary Reservoir, 1987 to 2005, calculated from the sum of all inflows (SCL 2008).

Year	Mean, Minimum and Maximum Monthly and Annual Flow into Boundary Reservoir (cfs, calculated from the sum of all inflows)												
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Annual**
1987	14,500	15,700	16,000	25,000	33,900	19,500	12,300	11,100	17,400	23,000	18,900	14,800	18,500
1988	10,100	12,300	18,900	27,600	28,900	22,400	11,800	6,400	10,300	20,700	21,400	14,000	17,100
1989	11,900	11,800	17,600	29,500	47,400	42,500	21,500	16,600	21,500	24,100	26,500	23,600	24,600
1990	22,800	22,200	19,900	39,100	46,300	71,100	31,900	14,100	16,600	26,300	28,000	20,900	29,900
1991	22,500	26,600	26,900	32,300	55,600	67,900	39,300	13,600	16,800	25,900	22,300	17,500	30,600
1992	15,300	13,400	17,200	19,800	22,500	15,900	13,700	10,300	14,900	25,800	20,000	12,600	16,800
1993	17,600	11,100	14,800	21,800	37,600	32,700	30,100	15,000	18,300	24,700	19,500	19,100	21,900
1994	18,600	15,000	16,500	21,100	25,900	26,600	11,400	7,700	10,400	19,300	20,500	13,000	17,200
1995	14,000	17,700	27,500	23,100	30,100	52,800	28,300	12,500	14,000	24,500	25,600	37,500	25,700
1996	27,800	41,600	43,400	54,600	69,200	76,400	32,300	18,600	15,400	20,500	18,700	18,600	36,300
1997	24,000	22,900	33,500	46,800	99,000	118,800	38,600	20,800	20,600	24,300	24,200	20,000	41,200
1998	17,200	14,000	18,500	25,800	39,900	53,900	32,500	15,600	15,200	17,900	19,100	16,700	23,900
1999	17,100	16,500	22,300	31,600	45,500	70,000	36,300	16,000	14,000	18,000	23,500	23,400	27,900
2000	17,800	15,100	18,900	35,800	45,300	38,600	20,700	10,000	12,300	19,000	16,600	13,400	22,000
2001	11,900	7,600	8,000	11,400	26,600	23,600	12,900	7,600	8,300	18,100	15,100	12,000	13,600
2002	16,800	16,400	18,000	29,100	46,600	82,100	37,200	14,000	12,000	16,300	15,000	16,200	26,700
2003	11,300	17,200	21,500	34,400	42,000	46,100	17,900	10,200	10,000	17,700	20,400	15,000	22,000
2004	11,800	13,700	18,100	20,600	35,500	37,100	22,900	13,800	19,400	23,700	17,300	21,000	21,300
2005	18,000	15,900	13,200	21,600	38,900	47,100	22,300	12,500	9,700	18,700	21,000	15,200	21,200
Maximum	*27,800*	*41,600*	*43,400*	*54,600*	*99,000*	*118,800*	*39,300*	*20,800*	*21,500*	*26,300*	*28,000*	*37,500*	*41,200*
Mean	*16,900*	*17,200*	*20,600*	*29,000*	*43,000*	*49,700*	*24,900*	*13,000*	*14,600*	*21,500*	*20,700*	*18,100*	*24,100*
Minimum	*10,100*	*7,600*	*8,000*	*11,400*	*22,500*	*15,900*	*11,400*	*6,400*	*8,300*	*16,300*	*15,000*	*12,000*	*13,600*

Table B.2-2. Mean, minimum and maximum monthly and annual total flow release from Boundary Dam to Pend Oreille River, 1987 to 2005 (SCL 2008).

Year	Mean, Minimum and Maximum Monthly and Annual Total Flow Release from Boundary Dam to Pend Oreille River (cfs)												
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Annual**
1987	14,500	15,700	15,700	25,200	34,100	19,200	12,100	10,800	17,300	23,000	18,800	14,700	18,400
1988	10,200	12,800	18,900	27,300	28,300	21,900	11,400	6,100	10,100	20,300	21,200	13,700	16,800
1989	11,800	11,800	18,200	30,000	47,400	41,500	21,300	16,400	21,200	23,500	26,200	23,100	24,400
1990	22,300	21,600	19,400	38,800	45,900	68,400	31,200	13,600	16,000	26,000	27,500	20,800	29,300
1991	21,900	26,200	26,900	32,300	55,100	67,100	39,100	13,000	16,600	25,600	21,900	17,000	30,200
1992	14,800	12,700	16,500	19,500	22,000	16,100	14,200	10,300	15,100	25,600	19,500	12,100	16,500
1993	17,100	10,500	14,300	21,100	36,400	32,100	29,200	14,000	17,600	23,900	19,300	18,900	21,300
1994	18,400	14,500	16,200	20,300	24,400	26,000	10,700	6,200	9,300	19,200	20,200	12,800	16,500
1995	13,300	17,100	27,500	22,800	29,500	50,900	28,300	11,700	13,700	24,700	28,600	37,900	25,500
1996	28,300	42,300	44,400	55,700	68,800	78,700	32,200	18,500	15,500	20,900	19,100	18,800	36,800
1997	24,600	22,600	33,200	47,400	99,200	116,200	38,600	20,000	19,700	23,400	23,300	20,000	40,700
1998	16,900	13,700	17,500	24,600	37,800	53,900	33,100	15,500	15,300	18,300	19,700	17,200	23,700
1999	17,800	17,200	23,500	32,700	45,500	67,600	36,500	16,200	14,300	18,400	24,200	24,200	28,200
2000	18,400	15,800	19,800	36,700	46,000	39,500	21,400	10,300	12,900	19,300	16,900	14,300	22,600
2001	12,600	7,900	8,600	12,000	26,200	23,500	13,100	7,700	8,200	18,500	15,600	12,500	13,900
2002	17,200	16,700	18,100	29,000	46,400	84,300	37,400	14,700	12,400	16,000	14,800	16,000	26,900
2003	10,700	17,000	21,200	34,300	40,900	44,900	17,300	9,500	9,400	17,400	20,300	14,800	21,500
2004	11,700	13,400	18,000	19,800	34,500	36,300	22,500	13,300	18,800	23,300	17,100	20,900	20,800
2005	17,800	15,700	13,200	21,500	38,100	46,000	21,800	12,000	9,200	18,300	20,400	14,700	20,700
Maximum	*28,300*	*42,300*	*44,400*	*55,700*	*99,200*	*116,200*	*39,100*	*20,000*	*21,200*	*26,000*	*28,600*	*37,900*	*40,700*
Mean	*16,900*	*17,100*	*20,600*	*29,000*	*42,400*	*49,200*	*24,800*	*12,600*	*14,300*	*21,300*	*20,800*	*18,100*	*23,900*
Minimum	*10,200*	*7,900*	*8,600*	*12,000*	*22,000*	*16,100*	*10,700*	*6,100*	*8,200*	*16,000*	*14,800*	*12,100*	*13,900*

Table B.2-3. Significant spills of record, 1987 to 2005.

Spill Begin (date)	Spill End (date)	Peak Spill (cfs)	Total Spill (acre-feet)	Peak Inflow (cfs)
5/28/1990	6/20/1990	53,400	970,000	83,000
5/19/1991	6/18/1991	56,300	1,534,000	86,900
5/17/1996	6/29/1996	82,900	3,121,000	93,400
4/23/1997	7/12/1997	124,200	8,309,000	137,900
5/25/1999	7/7/1999	43,800	1,209,000	80,100
5/23/2002	7/5/2002	55,400	2,344,000	95,600

To accurately represent historic flow data based on the Project record (1913 through 2005), Table B.2-4 is presented for the period from 1913 through 1938 (prior to upstream development of large storage projects) and from 1939 through 2005 (initiation and current development of upstream large storage projects). The statistics presented in Table B.2-4 are based on records from the following three sources:

1. Pend Oreille River below Z Canyon – USGS Gage 12398500 – 1913 to 1963

2. Pend Oreille River near International Boundary – USGS Gage 12398600 – 1964 to 1986

3. Pend Oreille River below Box Canyon Dam – USGS Gage 12396500 – plus the sum of all tributary inflows to Boundary Reservoir as listed in Table B.2-1 – 1987 to 2005.

Table B.2-4. Minimum, mean and maximum average annual flows.

Flow	1913 to 1938 (Prior to Development)	1939 to 2005 (Initiated and Current Development)
Minimum	15,000 cfs	13,600 cfs
Mean	26,100 cfs	26,800 cfs
Maximum	38,700 cfs	41,200 cfs

2.1.2. Storage Capacity

Metaline Falls is a geological feature that geographically divides the reservoir into two distinct reaches: an upstream reach that extends from Box Canyon Dam to Metaline Falls and a downstream reach that extends from Metaline Falls to Boundary Dam. The gradient of the upstream reach is much less than the gradient of the downstream reach, and depths in the upper section of the reservoir, above Metaline Falls, are much shallower, on the order of approximately 20 feet. The Pend Oreille River passes through a bedrock-controlled constriction located at Metaline Falls (elevation 1,970.6 feet NAVD 88).

Table B.2-5 summarizes the surface area and storage volumes by water surface elevation in the forebay. Figure B.2-2 depicts a storage volume curve for Boundary Reservoir developed in 2008, based on analysis of topographic and bathymetric surveys of the Pend Oreille River and adjacent floodplains between Boundary Dam and Box Canyon Dam from 2005 through 2007

(SCL 2008). The analysis incorporated the total storage volume of the reservoir, which was divided into two portions: a lower reservoir extending from Boundary Dam to Metaline Falls and an upper reservoir extending from Metaline Falls to Box Canyon Dam.

Table B.2-5. Surface area and storage volume in Boundary Reservoir versus water surface elevation in the Boundary Dam forebay (cells with bold, italicized font represent usable portion of storage).

Elevation (feet, NAVD 88)	Surface Area (acres)	Storage Volume (acre-feet)	Elevation (feet, NAVD 88)	Surface Area (acres)	Storage Volume (acre-feet)	Elevation (feet, NAVD 88)	Surface Area (acres)	Storage Volume (acre-feet)
1,744.03	1.22	0	1,860	218.30	11,616	***1,958***	***658.26***	***49,644***
1,745	1.26	1	1,865	227.19	12,730	***1,960***	***667.20***	***50,969***
1,750	1.47	8	1,870	238.85	13,895	***1,962***	***676.13***	***52,313***
1,755	1.72	16	1,875	253.73	15,126	***1,964***	***684.86***	***53,674***
1,760	2.01	25	1,880	265.18	16,424	***1,966***	***693.65***	***55,052***
1,765	2.37	36	1,885	278.89	17,784	***1,968***	***702.42***	***56,448***
1,770	2.80	49	1,890	296.23	19,222	***1,970***	***710.81***	***57,861***
1,775	73.35	240	1,895	311.24	20,740	***1,972***	***763.82***	***59,332***
1,780	78.23	619	1,900	327.69	22,338	***1,974***	***809.82***	***60,906***
1,785	82.33	1,020	1,905	344.94	24,019	***1,976***	***1,043.32***	***62,759***
1,790	85.68	1,440	1,910	367.24	25,800	***1,978***	***1,127.28***	***64,929***
1,795	88.56	1,876	1,915	386.00	27,683	***1,980***	***1,212.84***	***67,269***
1,800	104.11	2,357	1,920	404.82	29,660	***1,982***	***1,278.59***	***69,761***
1,805	108.13	2,888	1,925	426.88	31,739	***1,984***	***1,360.67***	***72,400***
1,810	114.23	3,444	1,930	453.20	33,939	***1,986***	***1,448.68***	***75,209***
1,815	118.55	4,026	1,935	477.99	36,267	***1,988***	***1,525.67***	***78,184***
1,820	122.60	4,629	1,940	540.93	38,815	***1,990***	***1,586.44***	***81,296***
1,825	126.19	5,251	1,945	573.63	41,601	***1,992***	***1,643.87***	***84,526***
1,830	156.06	5,956	1,948	594.72	43,354	***1,994***	***1,692.12***	***87,862***
1,835	172.34	6,777	1,950	608.73	44,557	***1,994.03***	***1,692.60***	***87,913***
1,840	180.10	7,658	1,952	623.93	45,790	1,996	1,723.79	91,278
1,845	188.81	8,581	1,954	637.49	47,051	1,998	1,755.84	94,758
1,850	197.16	9,546	***1,954.03***	***637.65***	***47,070***	2,000	1,792.14	98,306
1,855	206.41	10,554	***1,956***	***648.44***	***48,337***			

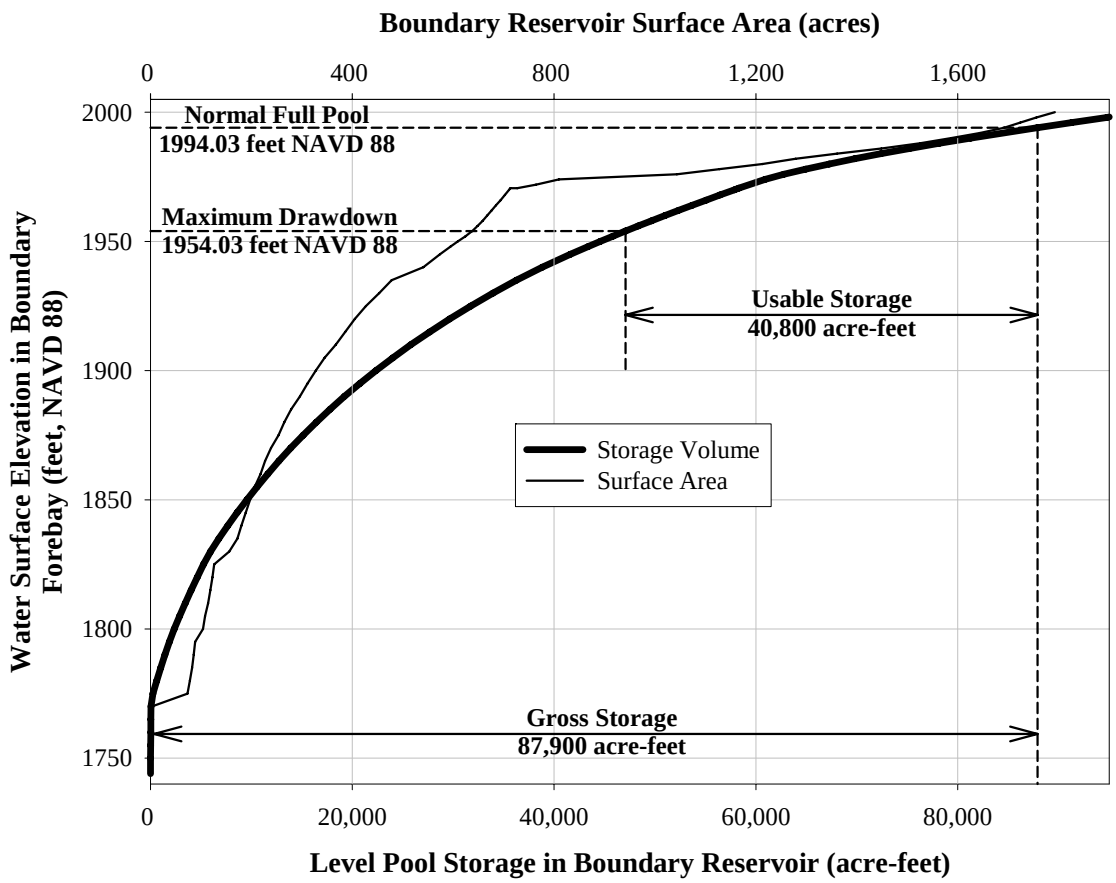

Figure B.2-2. Total storage volume in Boundary Reservoir above elevation 1,954.03 feet NAVD 88 versus water surface elevation in the Boundary Dam forebay. Storage volumes previously used by SCL, and storage volumes derived from surveys performed from 2005 through 2007 (SCL 2008).

2.1.3. Flood Conditions

During floods, the spillway gates are opened first until half their discharge capacity (total of approximately 54,000 cfs) is reached, and then the sluiceway is opened, with the sluice gates closest to the center of the dam opened first to reduce the possibility of eroding the abutments on the downstream side of the dam. Half the spillway gate capacity is reserved to maintain a steady forebay elevation while sluice gates are being opened. The sluice gates are either fully open or fully closed, and cannot currently be throttled. Opening times for the sluice gates are approximately 30 minutes each.

2.1.4. Critical Flow Months

The Pacific Northwest Coordination Agreement (PNCA), originally signed in 1964, calls upon the federal and non-federal operators of hydropower facilities in the region to plan and coordinate the operation of their projects. The PNCA parties include the federal government,

represented by the U.S. Army Corp of Engineers and the Bonneville Power Administration (BPA); the U.S. (Treaty) Entity, acting through the U.S. Army Corp of Engineers and the BPA; the U.S. Bureau of Reclamation; Portland General Electric Company; PacifiCorp; Avista Corp; Puget Sound Energy Company; PPL Montana; the municipalities of Seattle and Tacoma, Washington, and Eugene, Oregon; the PUDs of Chelan, Grant, Douglas, Pend Oreille, Cowlitz, and Snohomish counties; and others. The period of adverse stream flows that would produce the lowest amount of energy, while drafting the reservoirs from full to empty is used to establish the "firm" energy production of the entire Columbia River system. This period is referred to as the "critical period." It is calculated by the Northwest Power Pool pursuant to the PNCA. Historically, the critical period was determined from evaluation of the 60-year period of record from 1928 to 1988. The latest calculation done by the Northwest Power Pool shows the critical period to be November 1936 through April 1937. The PNCA currently defines the critical year from August 1, 1936 through July 31, 1937; however, the parties to the PNCA employ different methodologies for determining firm capability for planning purposes. The PNCA acknowledges specific operating priorities and limitations associated with each individual hydropower facility, which may originate with the federal authorizing legislation or Federal Energy Regulatory Commission (FERC) license requirements. These specific operating priorities and limitations may include specific water levels and flows for non-power purposes including fisheries, navigation, flood control, and recreation.

The use of the Northwest Power Pool critical period or PNCA critical year within the 1936 to 1937 timeframe for the Project is complicated by the absence of upstream storage projects on the Pend Oreille River system during that time, as illustrated in Figures B.2-3 and B.2-4. After the Hungry Horse, Kerr, and Albeni Falls projects were constructed, monthly flows in the Pend Oreille River at the Project did not get as low or as high as they did prior to upstream regulation. As a result, SCL uses the Project hydrologic record (SCL 2008) from 1913 to 2005, to determine historic critical flows that are more applicable to the Project.

Electrical energy generation (and demand) in the United States typically follows a seasonal pattern with two peaks (U.S. Department of Energy 2009), based on records of generation from all sources (including hydroelectric and all non-hydroelectric sources). One peak occurs in the winter (December and January), and the other peak occurs in the summer (July and August). A critical condition with regard to energy generation was assumed to occur when high demand coincided with low flows. Based on this reasoning, critical flow months were selected for both the winter and summer peak periods.

SCL determined that January and August 1988 represent historic critical flows, with regard to winter and summer peak demand seasons, respectively. The average flow of 10,100 cfs during January 1988 is a critical low flow during the winter peak demand season because it represents the driest January over the 56-year period from 1953 to 2005, and this flow is lower than any average flow in December during the same period. SCL also includes August 1988 as a critical flow month during the summer peak demand season when the average flow in the Pend Oreille River at the Project was 6,400 cfs. This is the driest monthly August flow for the Pend Oreille River over the 93+-year hydrologic record for the Project, and this flow is less than any average flow in July during the same period.

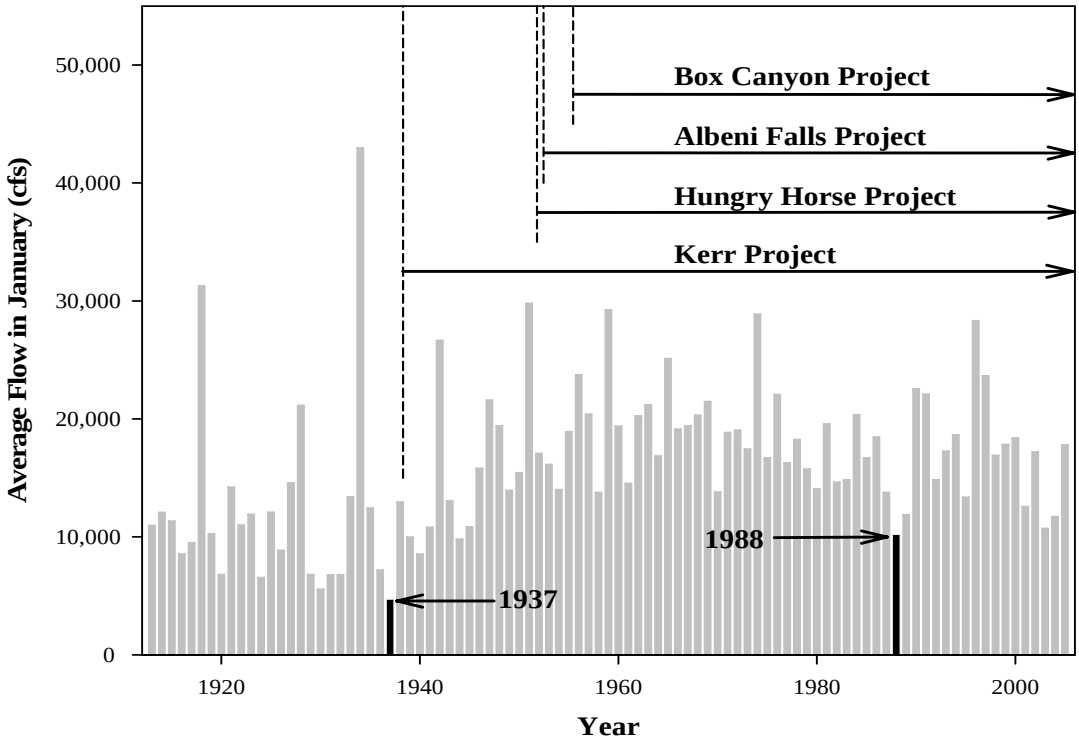

Figure B.2-3. Average January inflows to Boundary Project, 1913 to 2005, prior to and after regulation of inflow by upstream storage projects.

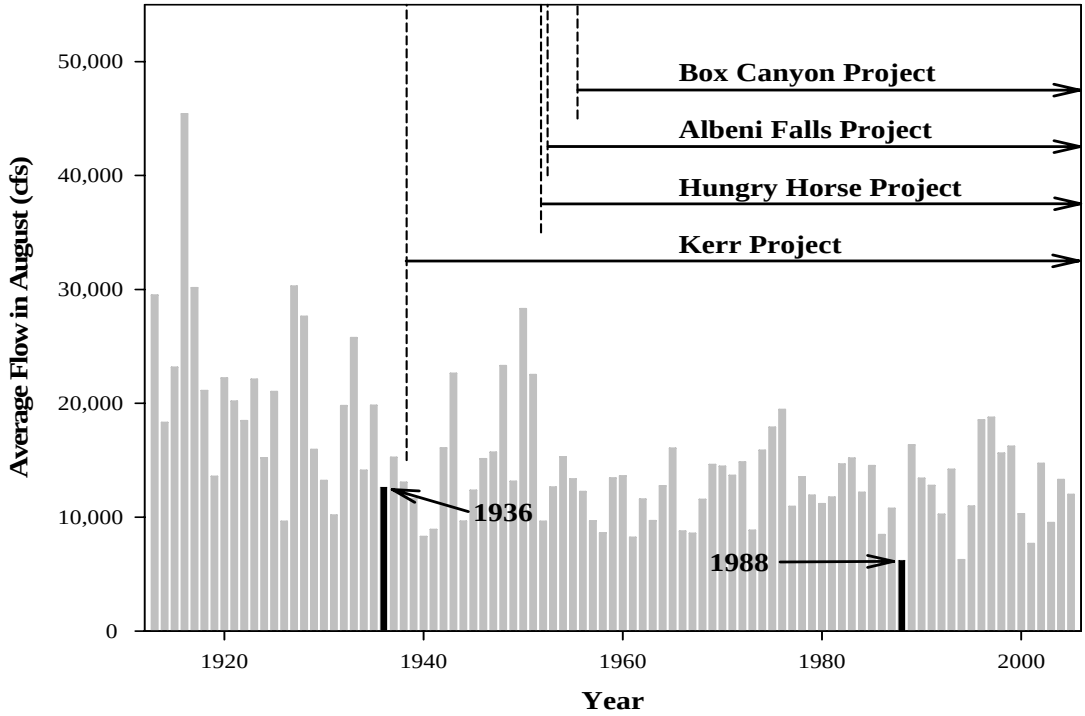

Figure B.2-4. Average August inflows to Boundary Project, 1913 to 2005, prior to and after regulation of inflow by upstream storage projects.

2.2. Project Operation During Adverse, Average, and High Inflow Years

Figures B.2-5 through B.2-7 illustrate the range of historical reservoir fluctuation in representative dry, average, and wet years (as defined by total reservoir inflows), selected from 1987 through 2005. Based on the calculated reservoir inflows and the historic generation, the driest year from 1987 to 2005 (2001) was selected as the representative adverse (dry) year, and a high flow year having the greatest average annual flow from 1987 to 2005 of record (1997) was selected as the representative high (wet) year. The average annual flow from 2001 ranks as the second driest year during the 96-year period from 1913 to 2008 and the average annual flow from 1997 ranks as the second wettest year during the long-term record. The year 2002 was selected as the representative average year because it has an annual average inflow that is close to the long-term average inflow.

Daily fluctuations in water surface elevation in the Boundary Dam forebay are minimal whenever the inflow to Boundary Reservoir exceeds plant capacity during the spring runoff, as illustrated in Figures B.2-6 and B.2-7 for an average and high inflow year, respectively. In contrast, the water surface elevation in the Boundary Dam forebay was allowed to fluctuate during the spring runoff during an adverse year (Figure B.2-5) because the inflow to Boundary Reservoir did not exceed the plant capacity.

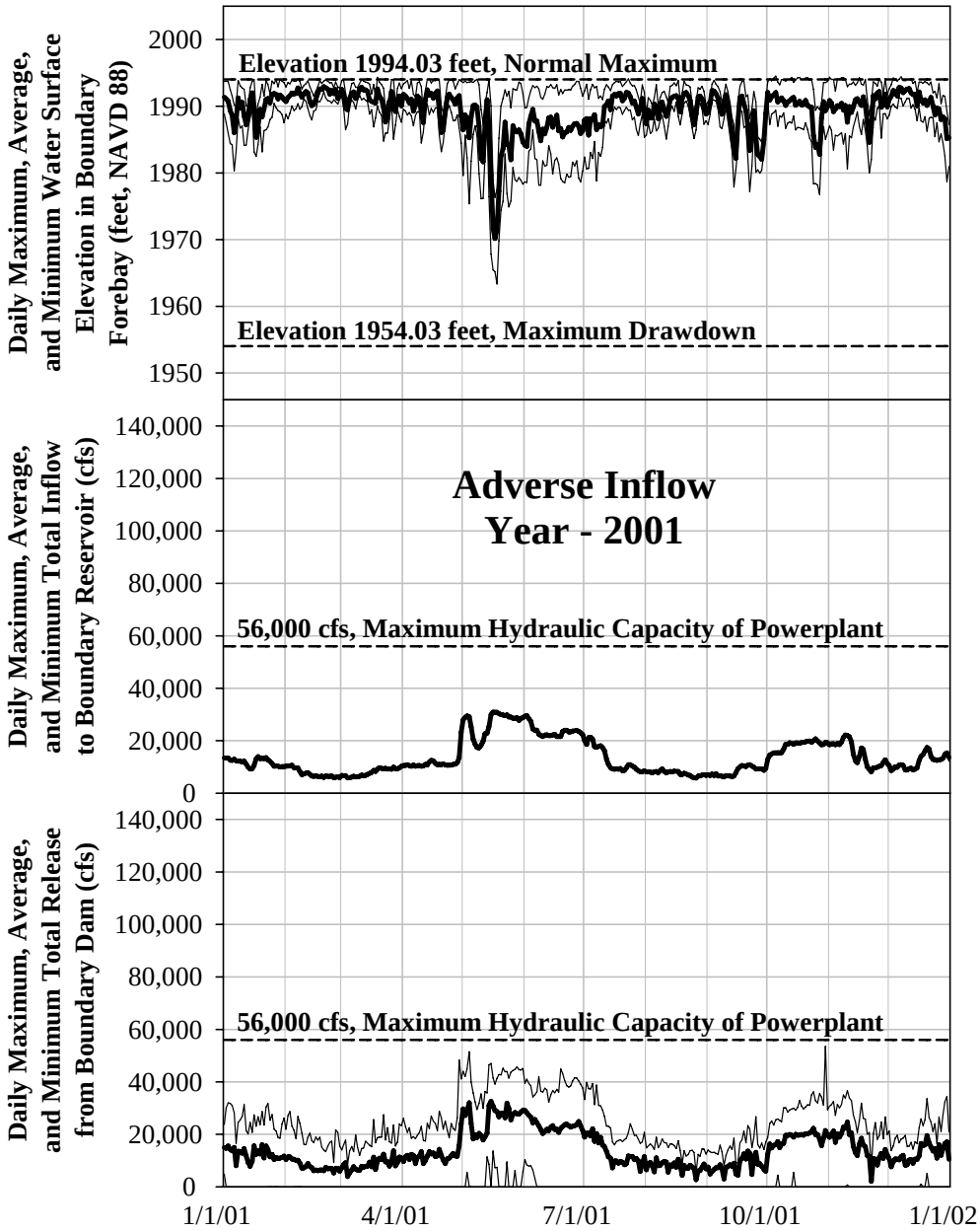

Figure B.2-5. Daily maximum, average, and minimum water surface elevation in Boundary Dam forebay, total inflow to Boundary Reservoir, and total release from Boundary Dam during 2001 (an adverse inflow year).

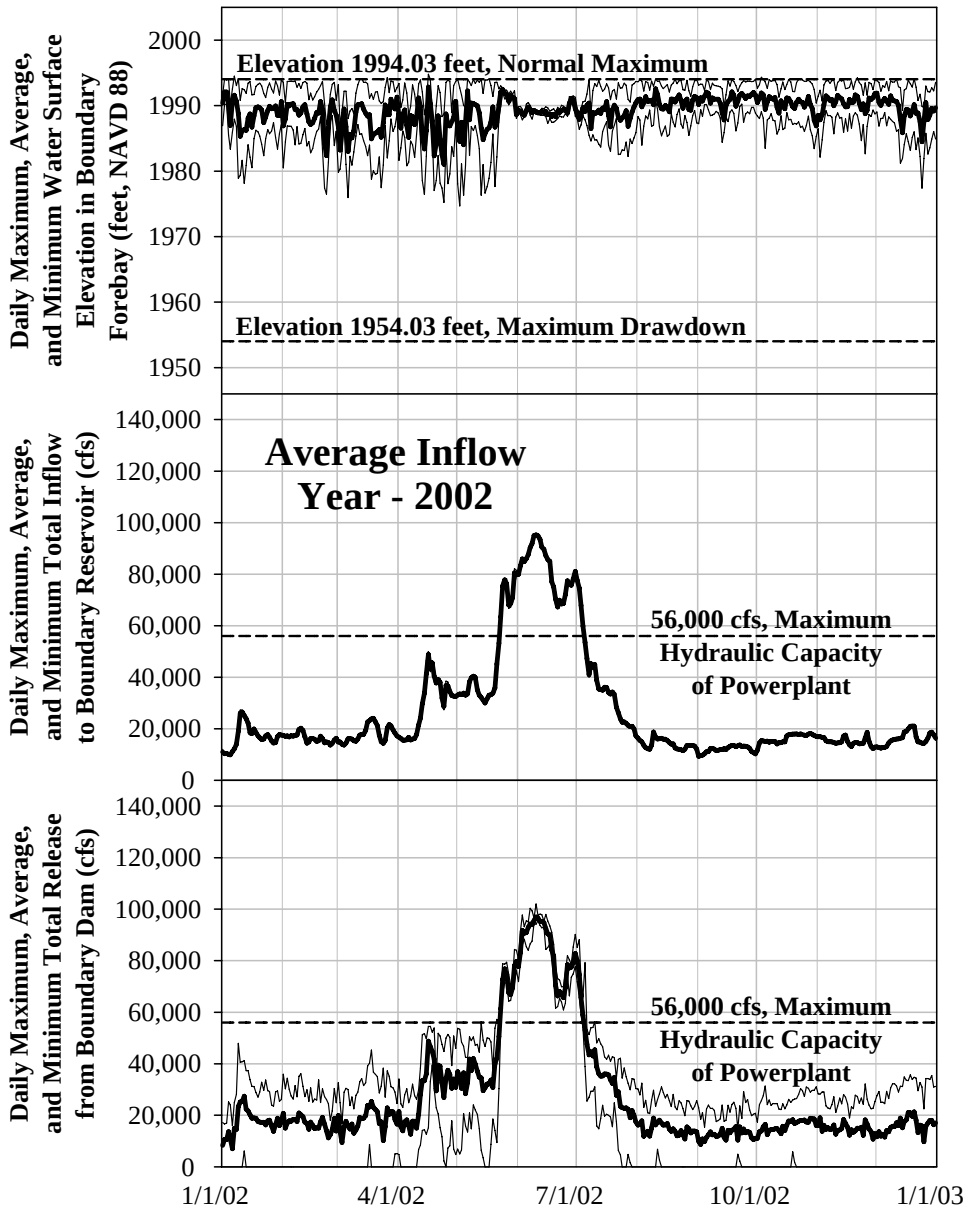

Figure B.2-6. Daily maximum, average, and minimum water surface elevation in Boundary Dam forebay, total inflow to Boundary Reservoir, and total release from Boundary Dam during 2002 (an average inflow year).

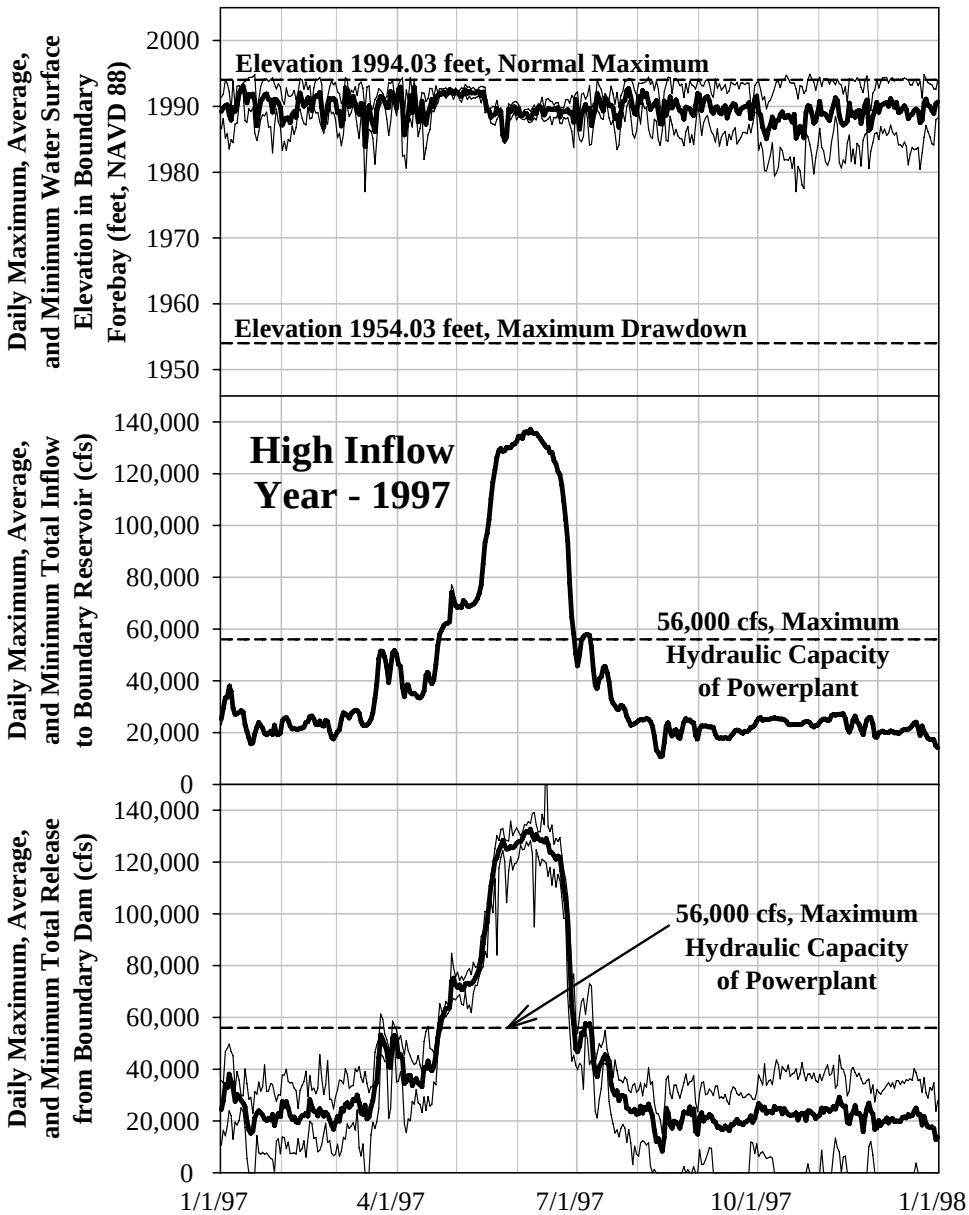

Figure B.2-7. Daily maximum, average, and minimum water surface elevation in Boundary Dam forebay, total inflow to Boundary Reservoir, and total release from Boundary Dam during 1997 (a high inflow year).

2.3. Flow Duration Curves

Annual and monthly total inflow duration curves for the period 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows, are presented in Figures B.2-8 through B.2-20.

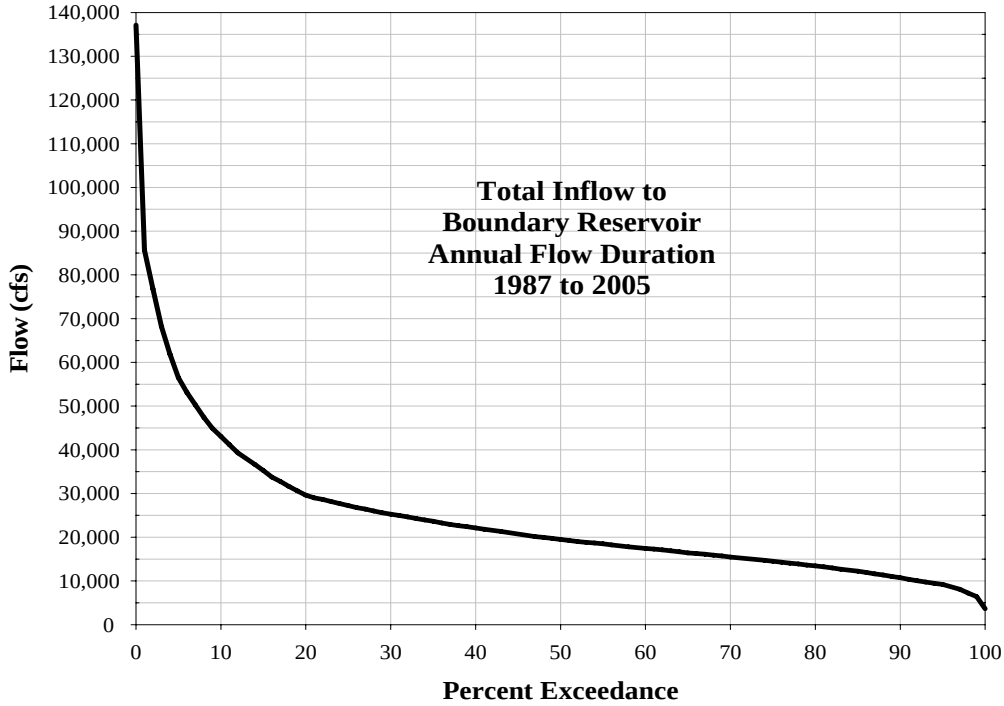

Figure B.2-8. Annual total inflow duration curve, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

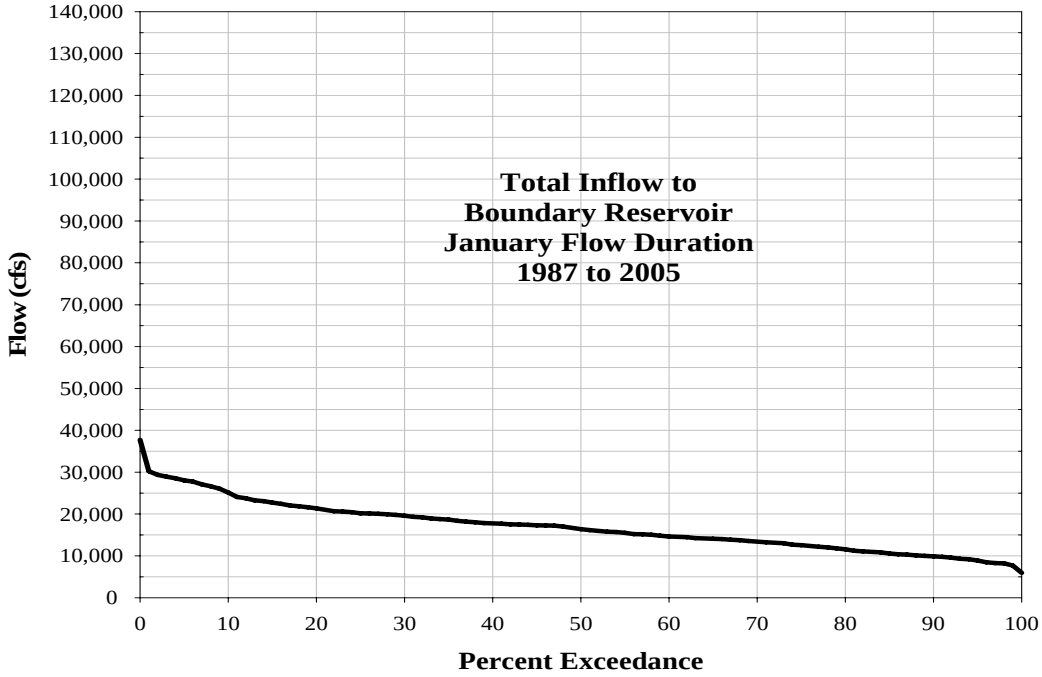

Figure B.2-9. Monthly total inflow duration curve for January, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

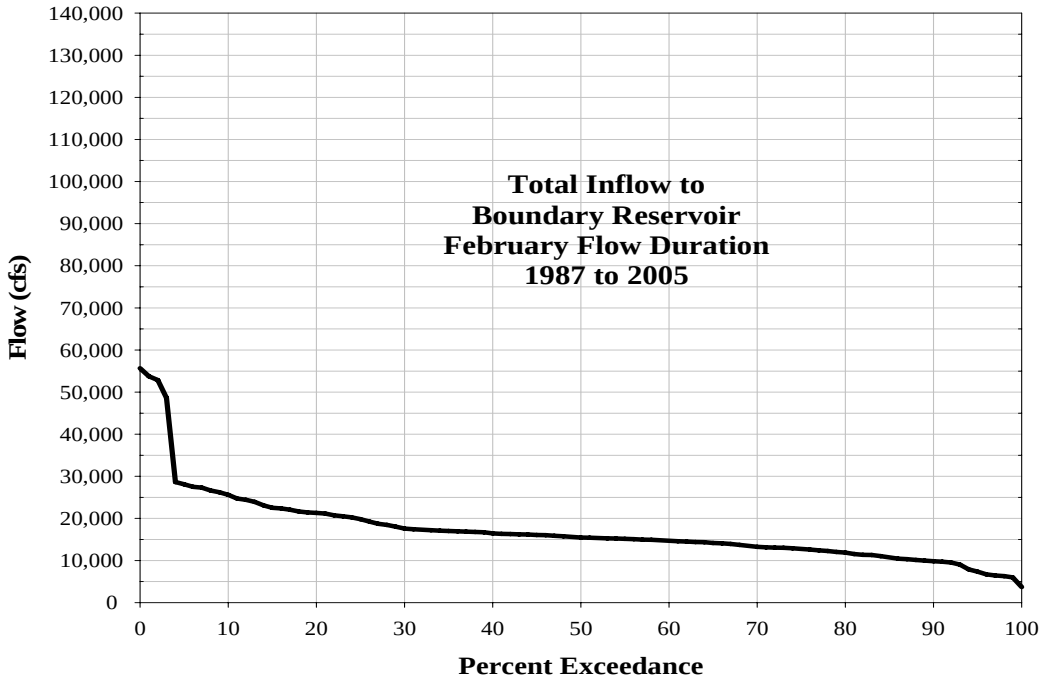

Figure B.2-10. Monthly total inflow duration curve for February, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

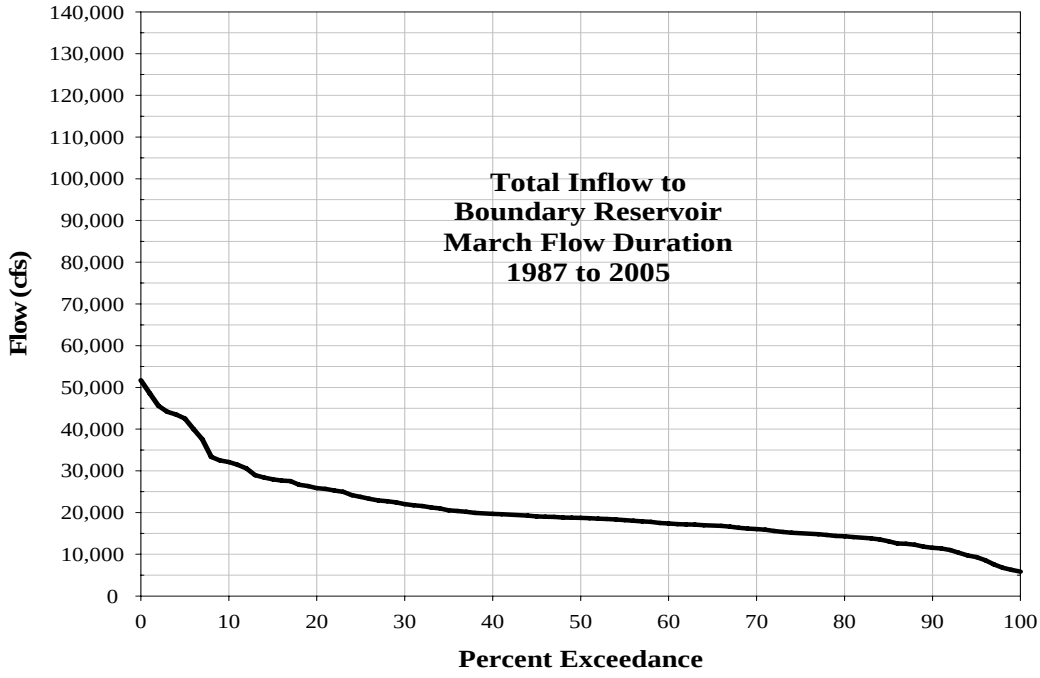

Figure B.2-11. Monthly total inflow duration curve for March, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

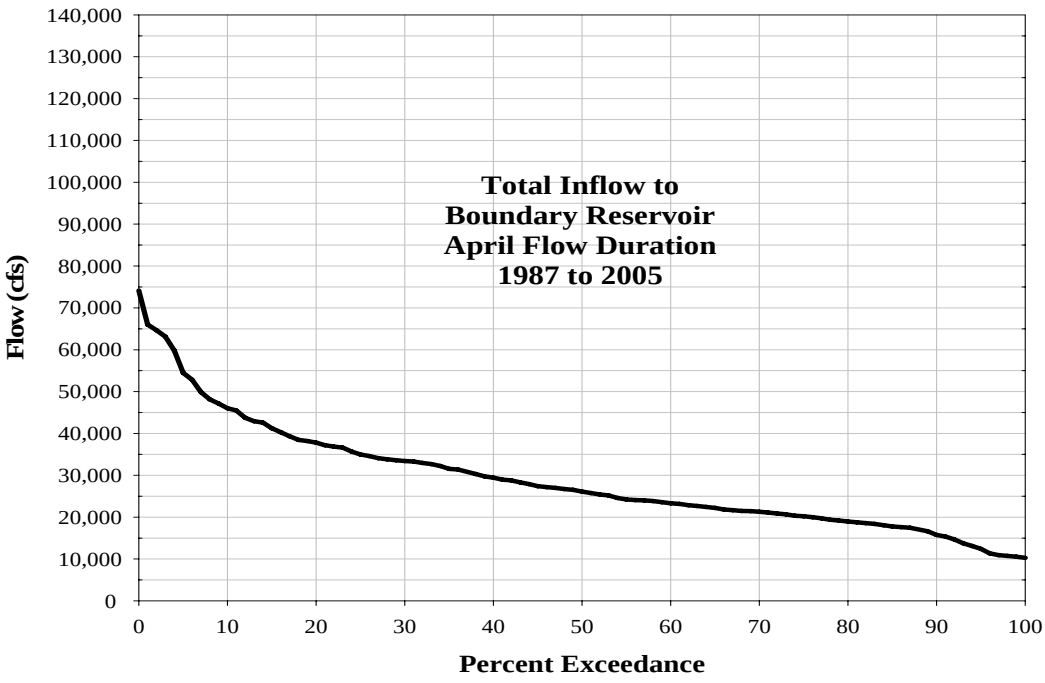

Figure B.2-12. Monthly total inflow duration curve for April, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

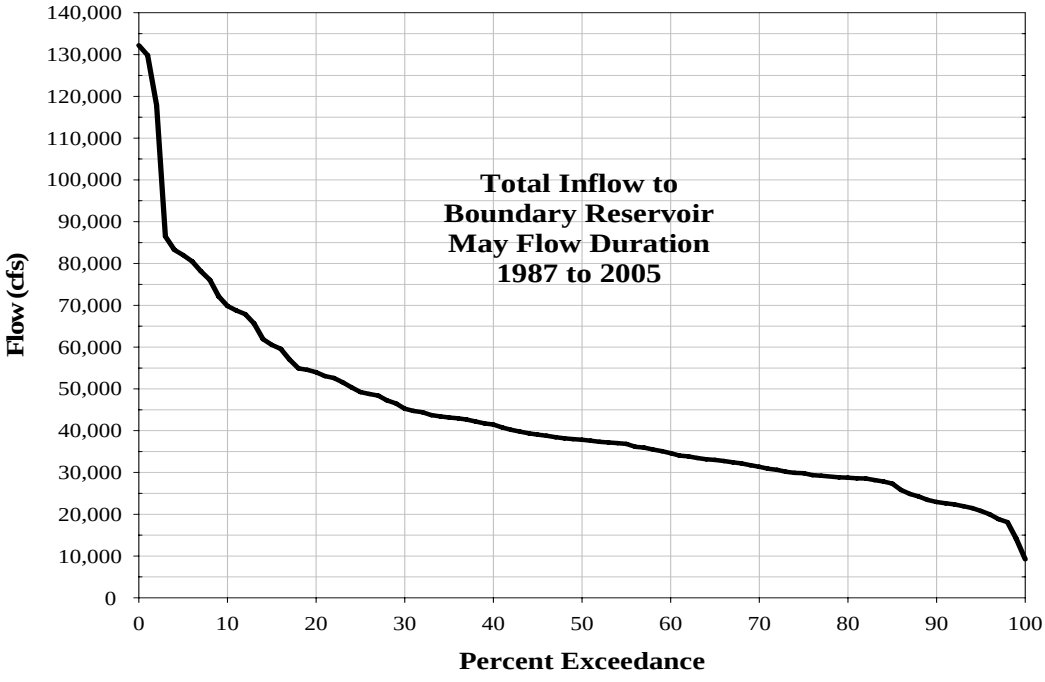

Figure B.2-13. Monthly total inflow duration curve for May, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

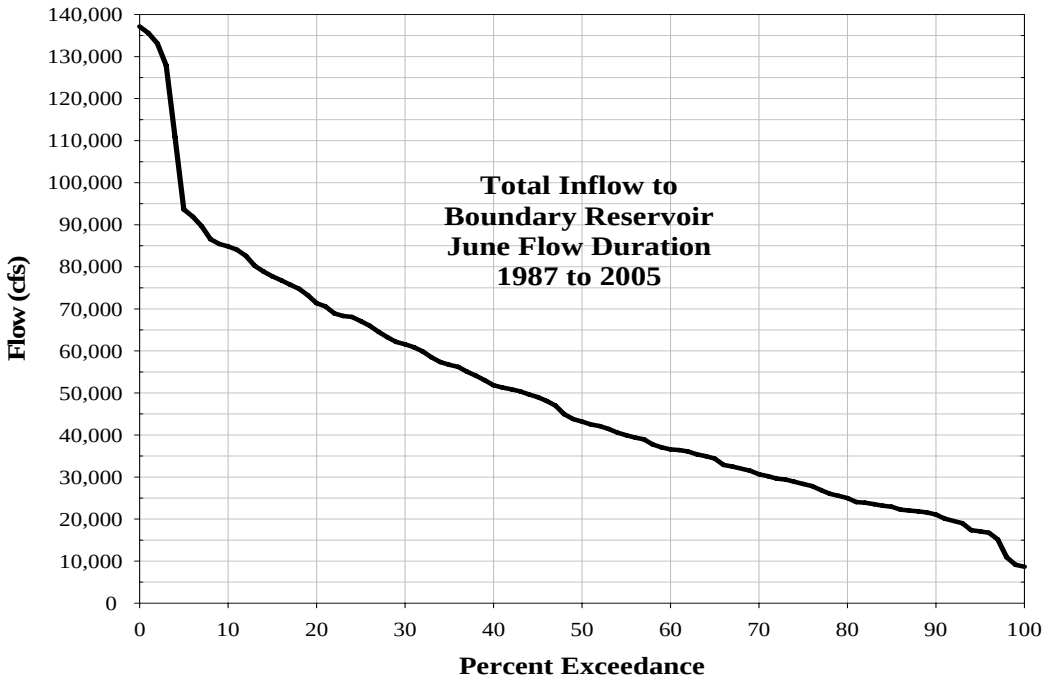

Figure B.2-14. Monthly total inflow duration curve for June, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

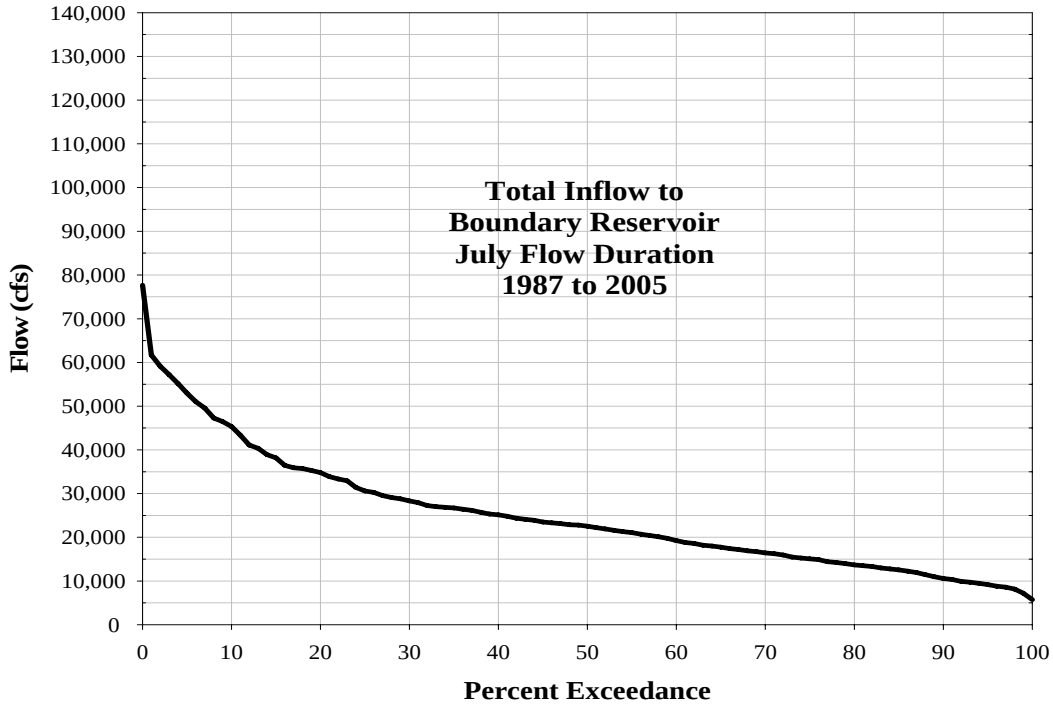

Figure B.2-15. Monthly total inflow duration curve for July, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

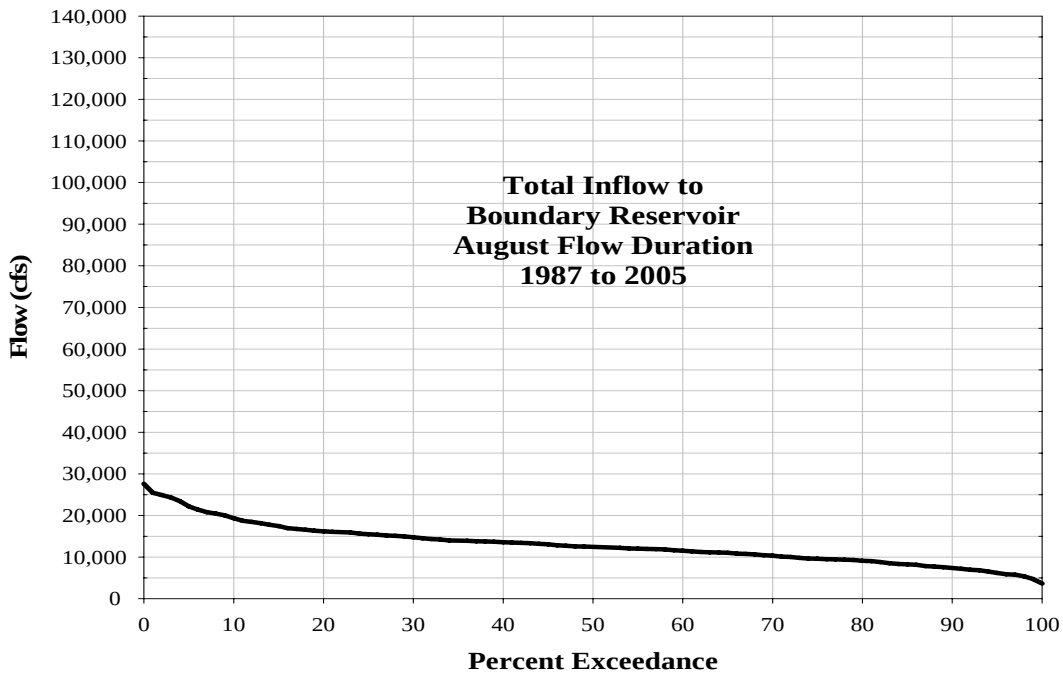

Figure B.2-16. Monthly total inflow duration curve for August, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

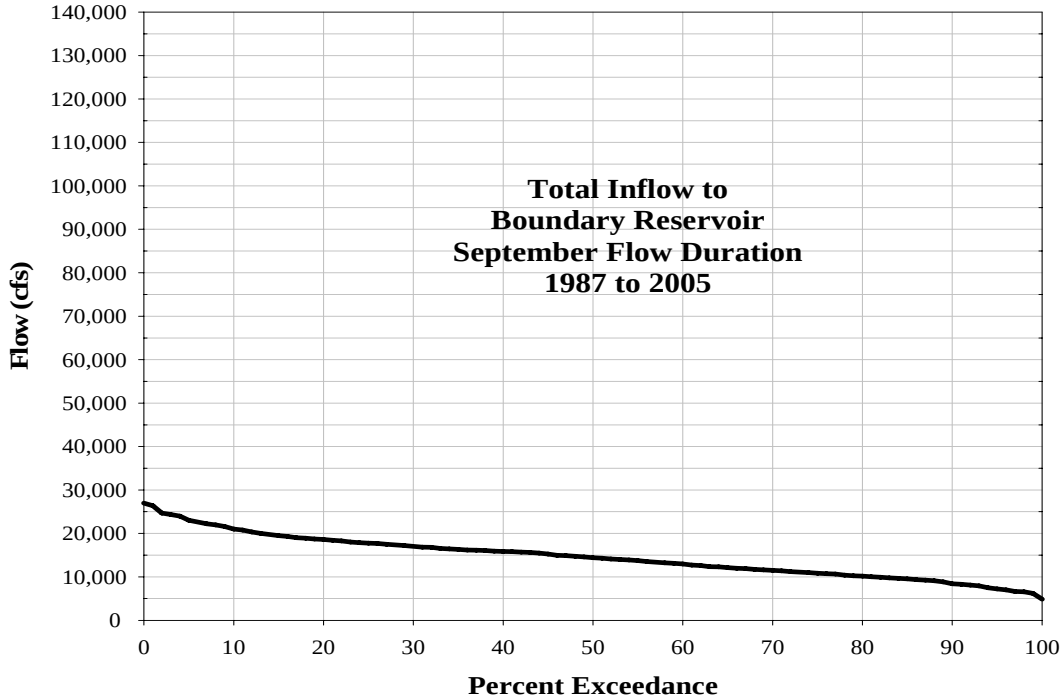

Figure B.2-17. Monthly total inflow duration curve for September, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

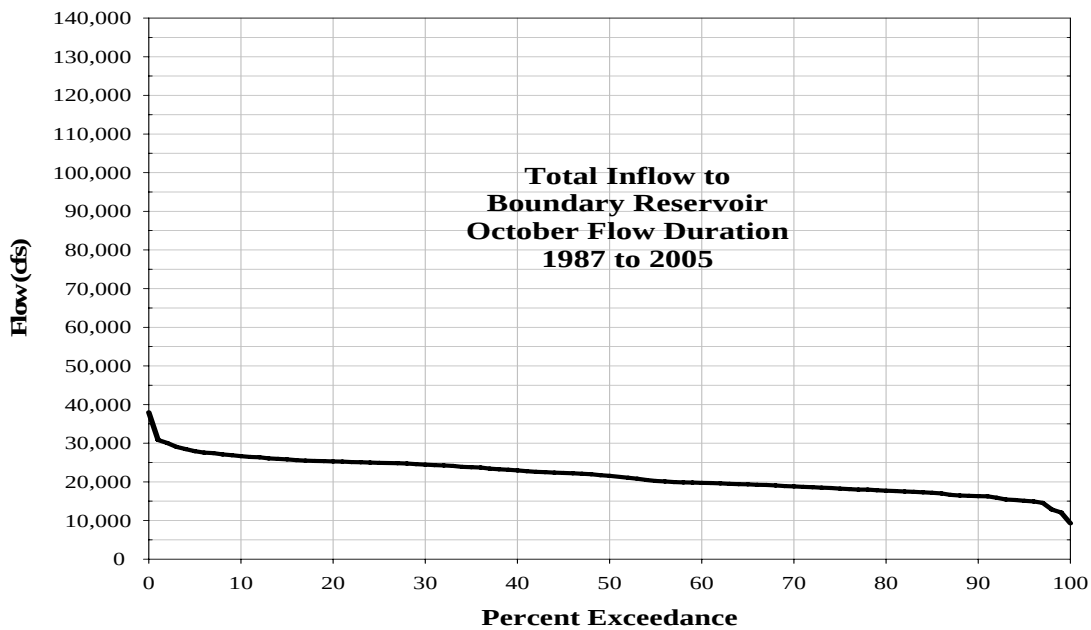

Figure B.2-18. Monthly total inflow duration curve for October, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

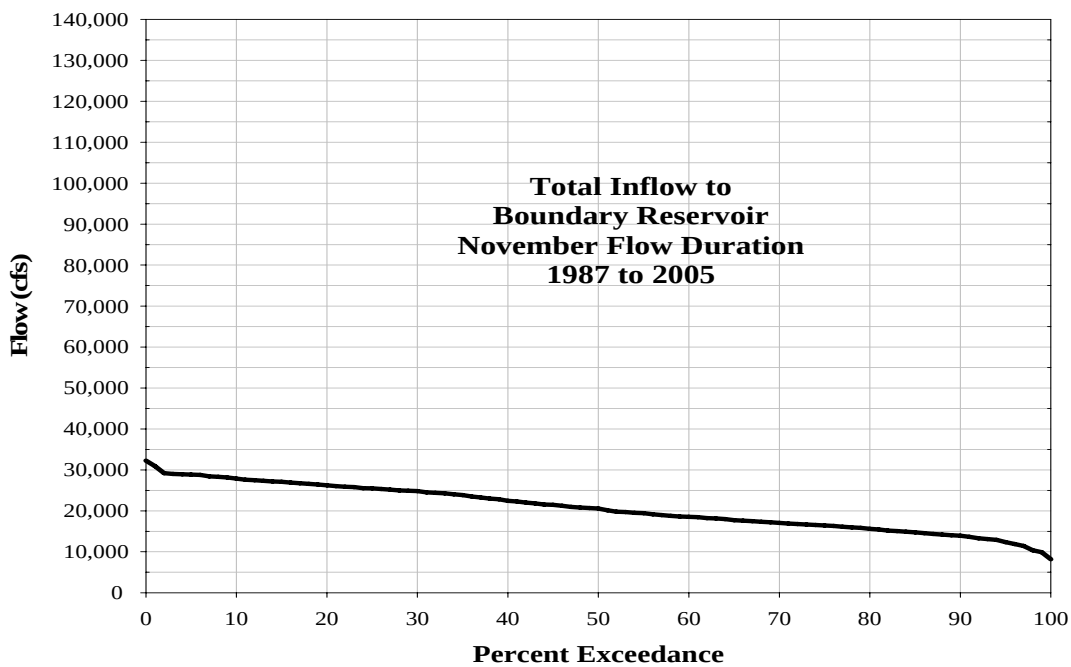

Figure B.2-19. Monthly total inflow duration curve for November, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

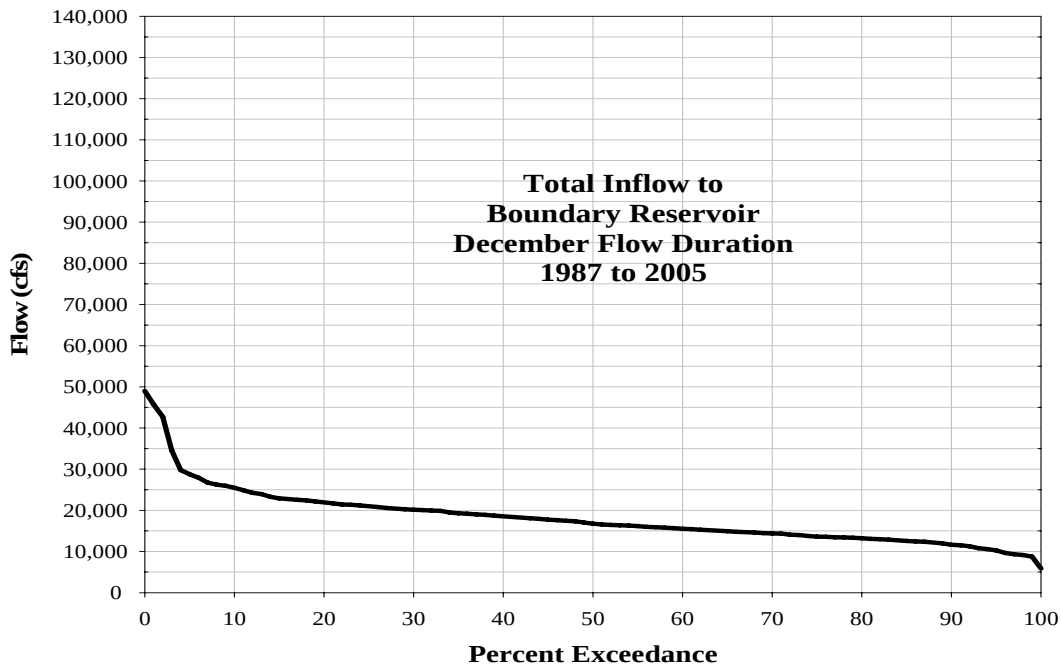

Figure B.2-20. Monthly total inflow duration curve for December, 1987–2005, based on streamflow data from USGS Gage 12396500 (Pend Oreille River below Box Canyon) plus the sum of all tributary inflows.

2.4. Rapid Drawdown Requirements

A current license obligation is that the Project provide for rapid drawdown of the reservoir to elevation 1,974 feet NAVD 88 in the event that mines in the vicinity of the town of Metaline Falls ever start to flood. The mines have workings under the reservoir, and SCL installed at least four concrete plugs to minimize any potential flooding of the mine workings due to initial reservoir filling. The seven sluiceways in the dam provide the means to quickly drawdown the reservoir to elevation 1,974 feet NAVD 88, thereby satisfying the current license obligation. The sluiceways are capable of maximum safe release of 252,000 cfs with the forebay at elevation 1,994 feet NAVD 88, and the estimated time to reach elevation 1,974 feet NAVD 88 is approximately 6.4 hours. To date, SCL has not needed to implement the rapid drawdown provision.

2.5. Transmission of Generated Electricity

Power is transmitted by six individual three-phase, 230-kV transmission lines up the vertical face of the left abutment of the dam to six pairs of transmission towers on top of the abutment. From there, each transmission line runs approximately 3,000 feet to a tower located adjacent to the BPA Substation. The Project transmission lines are connected to the BPA 230-kV bus system through disconnecting switches and circuit breakers (the switches and breakers are not part of the licensed Project). Through a “wheeling” arrangement (the transmission of electricity produced by one utility through facilities owned by another for a fee), the BPA transmits to Seattle

(approximately 300 miles from the Project) an amount of power equivalent to that supplied by the Project. A single-line diagram showing the transfer of electricity from the Project to the transmission grid is provided in Exhibit F of this License Application (Sheets 6 and 7).

3 Existing Resource Utilization

Project generating Units 51 and 53 each have a turbine rated at 204,506 hp (153,379.50 kilowatts [kW]) connected to a generator rated at 158,400 kW, Units 52 and 54 each have a turbine rated at 204,506 hp (153,379.50 kW) connected to a generator rated at 161,500 kW, and Units 55 and 56 each have a turbine rated at 259,823 hp (194,867.25 kW) connected to a generator rated at 200,000 kW for a total authorized installed capacity of 1,003,253 kW based on current turbine ratings and total generating installed capacity of approximately 1,039,800 kW (1,040 MW) (FERC 2007).

To provide a consistent comparison among existing and alternate operations (see Exhibit E, Section 3.3, Integrated Resource Analysis, of this License Application), the hourly energy production (megawatt hours [MWh]) was determined by the Scenario Tool (ST; CddHoward 2008; described in Section 5.1, Operations Modeling, of this Exhibit and in greater detail in Exhibit E, Section 4.4, Modeling Analysis). The ST uses real Project operating parameters and historic hydrologic data (dry, average, and wet inflow years) to produce the most efficient or optimized hourly total plant generation (MWh) based on perfect foresight of historic inflow conditions. Because the ST is consistent in applying optimization to hourly historic inflows, the ST does not exactly reproduce the historic day-to-day energy production due to variations in load demand, weather, operation and maintenance activities, emergency operations, and other operational decisions.

The estimated total average annual energy produced at the Project, based on optimizing Project operations for the average year (2002) hourly inflows, is 4,110,505 MWh (Table B.3-1). The actual 2002 energy produced by the Project was 3,961,282 MWh, which is less than a 4 percent difference relative to the estimated total average annual generation. This difference is due primarily to the ST's consistent, perfect foresight of actual hourly 2002 inflow conditions to optimize operations, which results in a slightly increased total annual energy production.

Details regarding proposed modifications to Project operations under the new license, including the modeling analysis of operational scenarios that led to the proposal, are provided in Exhibit E of this License Application.

Table B.3-1. Boundary Project monthly and total generation (in MWh), modeled and actual average inflow year (2002).

Month	Average year (modeled)	Average year (actual)
January	245,915	248,177
February	220,897	218,727
March	267,160	260,726
April	410,274	401,210
May	602,493	586,461
June	768,952	701,218
July	513,778	491,306
August	209,788	212,811
September	171,178	174,292
October	243,759	230,343
November	219,708	206,131
December	236,603	229,880
Total	**4,110,505**	**3,961,282**

3.1. Description of Plant Control

The Project is staffed 24 hours a day, seven days a week and is operated both locally and remotely. Manual control is used primarily for start/stop operation in response to requests from the Seattle System Operator. Once on-line, the Project operates in Automatic Generation Control (AGC) as a load-following resource. At any point in time, in response to specific system and plant requirements, one or more units may be taken off of AGC and operated locally.

3.2. Estimate of Annual Plant Factor

The average plant factor for the Project is approximately 0.45 based on the average annual energy production of approximately 4.1 million MWh (Table B.3-1) and the Project's installed capacity of 1,039.8 MW. The annual plant factor was estimated based on the total average annual energy production of 4,110,505 MWh (Table B.3-1) divided by the plant installed capacity times the number of hours per year (8,760 hours).

3.3. Estimate of Dependable Capacity

Because the Project has little storage (pondage) capacity, dependable capacity is based on the historic critical flows (see Section 2.1.4, Critical Flow Months, of this Exhibit) for January and August 1988 with regard to energy generation when high demand coincided with low flows during winter and summer peak demand seasons, respectively. Using the average flow of 10,100 cfs for January 1988 and the 20 feet of usable pond from elevation 1,994 to 1,974 feet NAVD 88, a dependable capacity of approximately 1,040 MW for 3 hours could be attained by the Project during critical winter demand based on modeled results. Using the average flow of 6,400 cfs for August 1988 and the 20 feet of usable pond from elevation 1,994 to 1,974 feet NAVD 88,

a dependable capacity of approximately 1,040 MW for 1 hour could be attained by the Project during critical summer demand based on modeled results.

The Project is currently capable of generating up to approximately 1,103.6 MW (see Section 3.5 of this Exhibit) at a rated head of 250 feet with all units running and operating at maximum hydraulic capacity. The power plant is loaded at or greater than 1,040 MW less than 1 percent of the time based on the hourly generation record from 1997 through 2007.

3.4. Rule Curve

The Project guide for storage and release of storage water is based on the storage-capacity curve (Figure B.3-1; also see Section 2.1.2, Storage Capacity, of this Exhibit) and generation availability based on variations in hourly, daily, and weekly system loads. The Project typically begins generating in the early morning hours and ramps up to meet peak morning demand. Power is generated throughout the day, rising and falling in response to customer demand, and then increases again to meet peak evening demand. The capacity left vacant in the reservoir is filled on a voluntary basis if adequate water is available from upstream releases.

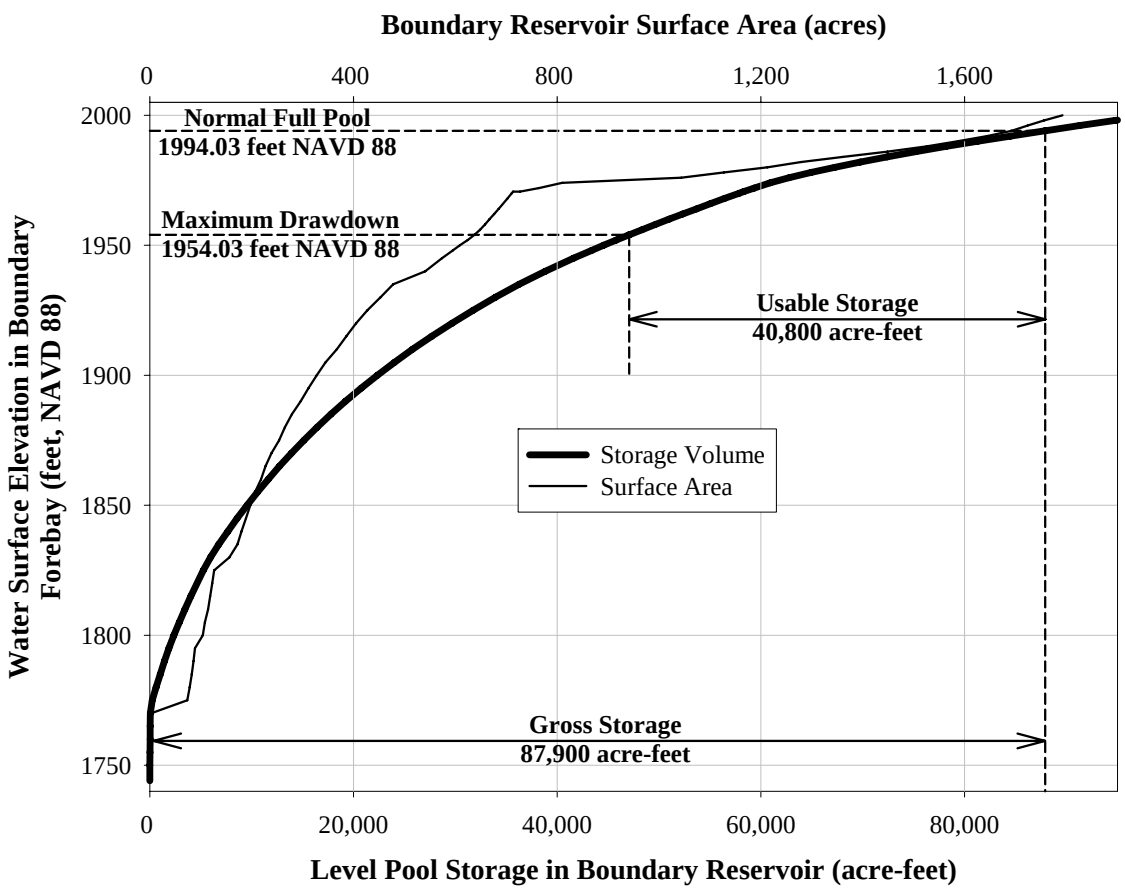

Figure B.3-1. Usable storage volume in Boundary Reservoir above elevation 1,954.03 ft NAVD 88 versus water surface elevation in the Boundary Dam forebay (SCL 2008).

The Project reservoir's nominal usable storage capacity is approximately 40,843 acre-feet (elevation 1,954 feet NAVD 88 to elevation 1,994 feet NAVD 88) (SCL 2008). Because of the large volume of water flowing through the system and the limited amount of storage capacity in Boundary Reservoir, the residence time of the reservoir is very short. Maximum residence time is less than four days, but more typically the residence time is less than two days (Pickett 2004).

3.5. Tailwater Rating Curves

The Project power plant tailwater curve is shown in Figure B.3-2.

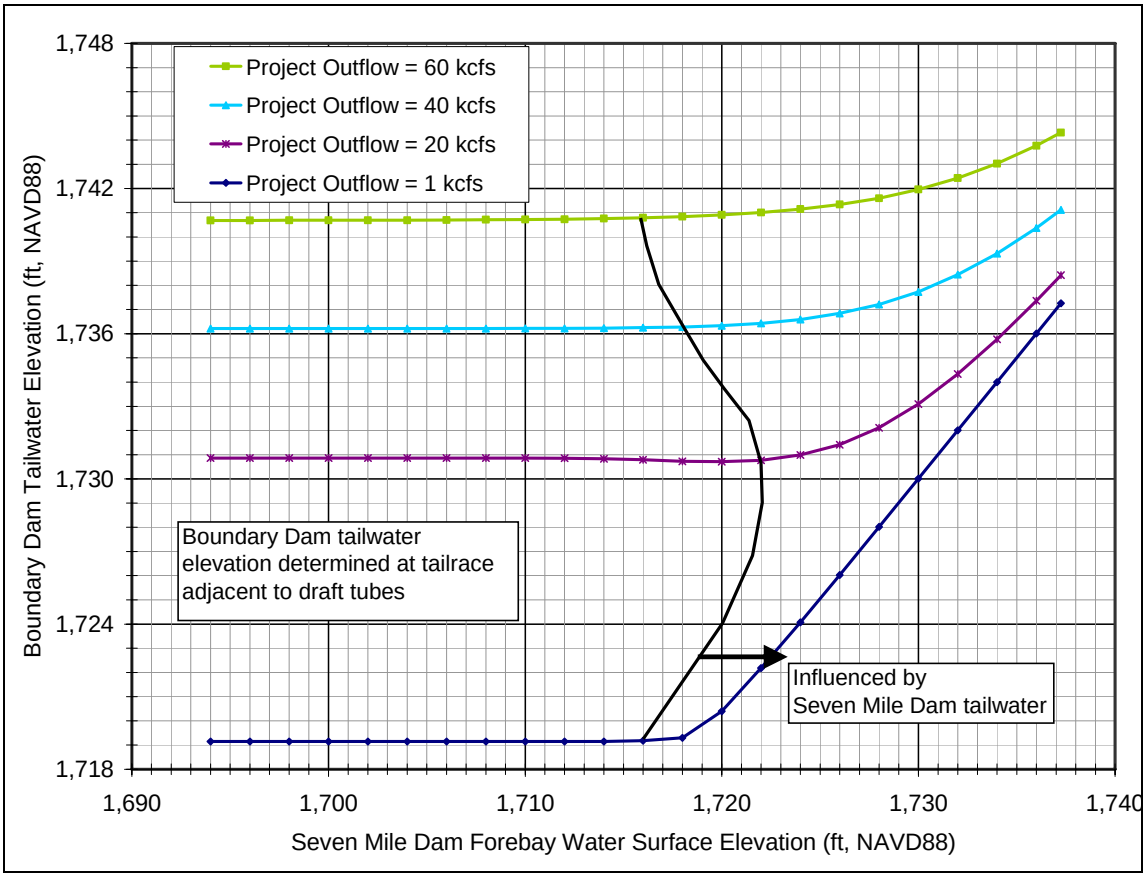

Figure B.3-2. Boundary power plant tailwater curve.

3.6. Estimated Power Plant Hydraulic Capacities and Capabilities

At the normal maximum water surface elevation of 1,994 feet NAVD 88 at the forebay, the Project has a maximum hydraulic capacity of approximately 56,000 cfs. Estimated capacities, efficiency, and generator output for the six units at the Project are summarized in Table B.3-2 and power plant capabilities for maximum, normal (rated), and minimum heads are shown in Figure B.3-3.

Table B.3-2. Estimated capacities, efficiency, and generator output for the six turbine units in the Boundary Project power plant.

Unit number	Generator Installed Capacity (kW) (250 ft rated head) [1]	Minimum Hydraulic Capacity (cfs)[2]	Maximum Hydraulic Capacity (cfs)	Normal Hydraulic Capacity (cfs) (250 ft rated head)			Efficiency (%) [4]			Generator Output (kW) (250 ft rated head)		
				Half gate	Best gate	Full gate	Half gate	Best gate	Full gate	Half gate	Best gate	Full gate[5]
51	158,400	4,400	9,500	5,297	7,616	9,500	86.53	92.8	87.5	94,500	146,500	172,500
52	161,500	2,700	9,500	5,297	7,616	9,500	86.53	92.8	87.5	94,500	146,500	172,500
53	158,400	2,700	9,500	5,297	7,616	9,500	86.53	92.8	87.5	94,500	146,500	172,500
54	161,500	2,700	9,500	5,297	7,616	9,500	86.53	92.8	87.5	94,500	146,500	172,500
55	200,000	6,700	11,350	6,155	9,407	11,350	81.9	89.8	87.3	104,700	178,500	206,800
56	200,000	6,700	11,350	6,155	9,407	11,350	81.9	89.8	87.3	104,700	178,500	206,800
Total	1,039,800	25,900	60,700 [3]	33,498	49,278	60,700	--	--	--	587,400	943,000	1,103,600

Notes:

1 Per FERC Order Amending License and Revising Annual Charges, dated November 2, 2007. Total authorized capacity is 1,003,253 kW based on turbine installed capacities.

2 These flows are provided based on turbine operating limits, not a reduced head. The rated head for the Boundary power plant is 250 feet net head. The standard minimum head is 237 feet net. These values are based on the below bullets.

- Unit 51 has a prohibited zone less than 70 MW due to penstock surging.
- Units 52 - 54 have a minimum operating point at 40 MW. All Noell runners (51- 54) should be run at loads greater than 80 MW due to rough operations, but for short periods they may be run lower to pick up morning loads.
- Units 55 and 56 are operated above 125 MW to reduce air admission that contributes to total dissolved gas (TDG) levels in the tailwater.

3 At the rated head of 250 feet, 100 percent gate, each unit can produce these flows individually, which total 60,700 cfs. However, the average net head at full plant capacity is 241 feet. At 241 feet net head, the full plant output is 990 MW at a flow rate of 56,000 cfs.

4 Turbine efficiency values (not generating unit efficiency values that include generator losses).

5 Full gate generator output is based on 100 percent full gate hydraulic capacities at rated net head of 250 feet. The total generator output of 1,103.6 kW is not possible since all units cannot operate at full gate capacities and maintain a rated net head of 250 feet (See Note 3).

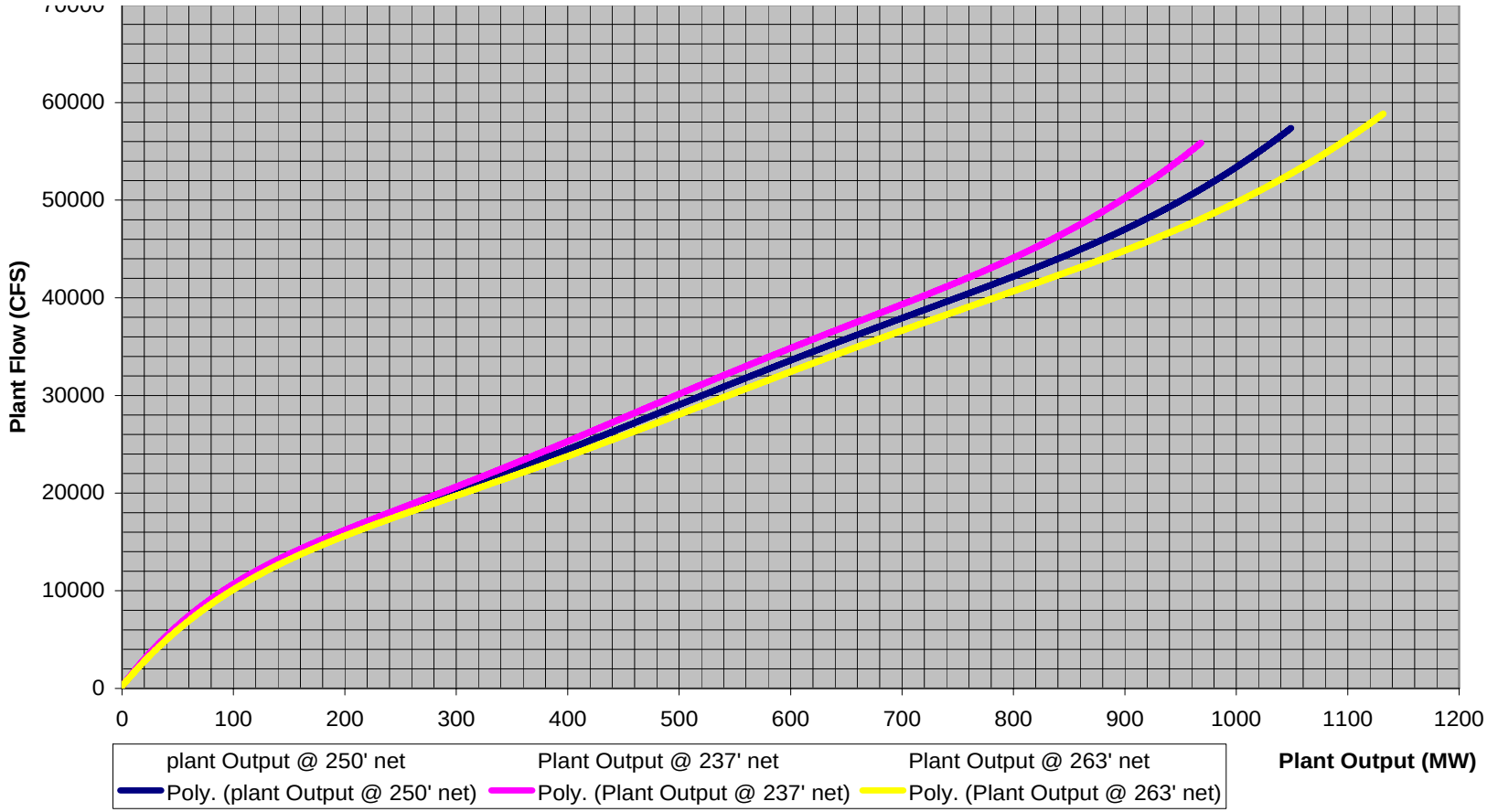

Figure B.3-3. Boundary Project power plant capability at net heads of 237 ft (minimum), 250 ft (normal) and 263 ft (maximum).

4 Use of Project Power

The Project is SCL's primary load-following resource and its power is used to meet within-hour load following needs. SCL uses the output under critical water conditions, approximately 3 million MWh, to serve retail load and satisfy the agreement with the Pend Oreille County PUD. Pend Oreille County PUD buys up to 48 MW from the Project. Non-firm output results when instream flow conditions are greater than critical and is sold on the secondary market.

The Project's power needs are approximately 7,900 MWh per year. This is approximately 0.0025 percent of output under critical water conditions and approximately 0.0020 percent of output under average water conditions.

There are no fixed purchasers of non-firm power from the Project. SCL does not typically identify a specific resource in its portfolio when transacting with counterparties in the short-term markets.

5 Future Resource Utilization

SCL proposes to operate the Project as it does under the current FERC license, but with formalization of current voluntary measures, including water surface elevation restrictions from Memorial Day to Labor Day for recreation enhancement and turbine unit sequencing to reduce total dissolved gas (TDG) production. Existing Project operations are described in Section 2 of this Exhibit and the voluntary measures to be formalized are described in Section 5.3, Proposed Changes to Project Operations.

5.1. Operations Modeling

SCL developed a suite of models and post-processing analyses to support the evaluation of existing and alternate operations (described in greater detail in Exhibit E, Section 4.4, Modeling Analysis, of this License Application). One of the models, the ST, is an Excel® spreadsheet-based hydroelectric operations tool tailored to the requirements of relicensing for the Project (CddHoward 2008). Using an hourly time step, the ST optimizes Project energy production using as input existing turbine efficiency curves, current storage capacity, and historic hydrologic data under specific operational constraints for three hydrologic periods corresponding to the adverse (dry) year, average year, and high (wet) inflow years as presented in Section 2 of this Exhibit. For each alternate operation (scenario), output from the ST consists of an hourly time series of Project energy production (MWh), release (cfs), and forebay water surface elevations (feet) to serve as input to the Hydraulic Routing Model (HRM), which then computes water surface elevations at multiple locations in the reservoir to assess changes in habitat and recreation parameters further as described in Exhibit E.

5.2. Facility Enhancements

SCL proposes to install new high efficiency turbines in Units 55 and 56. The turbine runner upgrades will increase efficiency, i.e., they will use the same flow to produce a greater amount of energy and will have a higher total generation capacity. The turbine runner efficiency upgrades

will be performed concurrently with planned electrical generator rewinds and step-up transformer replacements, which are scheduled for Years 1 and 2 after license issuance.

Reconnaissance-level engineering and cost studies for the turbine runner upgrades were performed in 2008 and 2009. Results indicate that the installed capacity for each turbine will increase from 200 MW to 215 MW (i.e., the electrical output from the generator) (see Figure B.5-1), for an increase of total Project capability from 1,040 MW to 1,070 MW and an estimated increase in average annual generation of 39,838 MWh. Cost estimates for this effort are detailed in Exhibit D of this License Application.

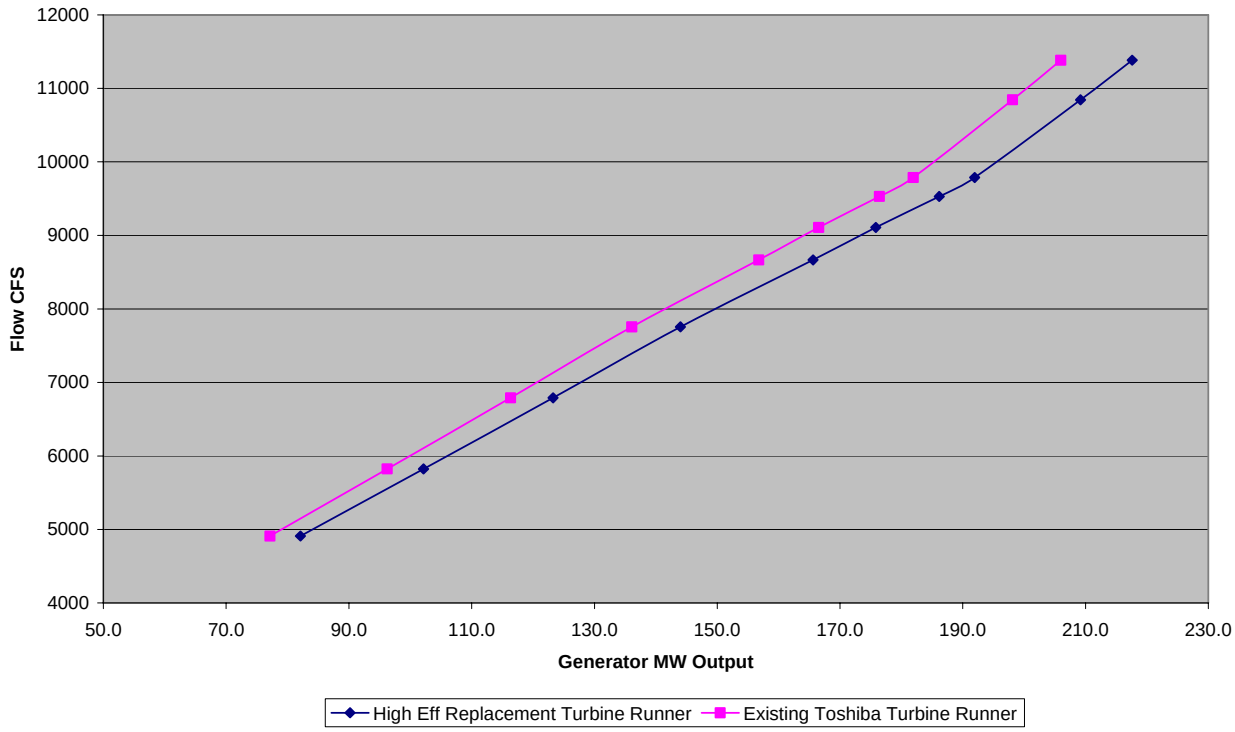

Figure B.5-1. Comparison of the efficiency of the existing and the proposed turbine runners of Units 55 and 56.

SCL also plans to rewind the generators and replace the turbine runners and transformers for Units 51 through 54 during the new license term; however, it is not expected at this time that these changes will result in an increase in capacity or generation.

Descriptions of other proposed modifications and enhancements to Project facilities are included in Exhibits A and E of this License Application.

5.3. Proposed Changes to Project Operations

As noted above, during the new FERC license term, SCL proposes to operate the Project as it is currently licensed, but with the formalization of two currently voluntary operational measures: forebay water surface elevation restrictions primarily for summer recreation enhancement and turbine unit sequencing to reduce TDG production. A general description of Project operations is provided in Section 2 of this Exhibit, and the voluntary measures to be formalized are described below.

From Memorial Day weekend (starting Friday evening) through Labor Day weekend (on Monday evening), forebay water surface elevations will be maintained at or above 1,984 feet NAVD 88 from 6:00 am through 8:00 pm to facilitate recreational access and use. From 8:00 pm through 6:00 am, forebay water surface elevations will be maintained at or above elevation 1,982 feet NAVD 88. From Labor Day weekend to Memorial Day weekend, operating the Project as it is currently operated will result in forebay water surface elevations fluctuating between 1,994 feet and 1,974 feet NAVD 88, and minimum forebay elevations will often be above 1,980 feet NAVD 88. Under SCL's proposed operations, the 1,984- and 1,982-foot water surface elevations will be license requirements that cannot be violated except for conditions such as equipment failures, maintenance activities, electrical and mechanical device limitations, safety inspections, testing, natural disasters (e.g. lightning), compliance with Western Electricity Coordinating Council (WECC) and North American Electric Reliability Council (NERC) requirements, capacity and energy emergencies, and any event that triggers the Project Emergency Action Plan (EAP).

To reduce TDG under normal, non-spill operations, SCL will operate Units 55 and 56 above 125 MW and sequence their startup and shutdown so that they are the last units to be brought on line and the first units to be shut down (see Section 5.4.7 of the Evaluation of Total Dissolved Gas and Potential Abatement Measures Final Report [SCL 2009] for greater detail).

During the new license term, SCL plans to upgrade equipment at the Project's power plant (see Section 5.2 of this Exhibit). Proposed upgrades to the Unit 55 and 56 turbines may reduce or eliminate the conditions that in the past have led to TDG production during non-spill operations. When the proposed turbine upgrades are completed, SCL plans to re-evaluate the need for the unit sequencing identified above and adjust the approach to, or eliminate, the sequencing restrictions as appropriate.

Further details regarding proposed modifications to Project operations under the new license, including the modeling analysis of operational scenarios that led to the proposal, are provided in Exhibit E of this License Application.

6 References

CddHoward Consulting, Ltd. 2008. Seattle City Light Boundary Dam Scenario Tool Overview and Technical Documentation (July 23, 2008).

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