Exhibit 2

PSE PUGET SOUND ENERGY
The Energy To Do Great Things

INCREMENTAL HYDROPOWER GENERATION AT THE BAKER RIVER PROJECT

REQUEST FOR FERC CERTIFICATION OF HYDROPOWER PRODUCTION FROM ADDITIONAL CAPACITY

BAKER RIVER HYDROELECTRIC PROJECT
FERC No. 2150

Puget Sound Energy
Bellevue, Washington

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Executive Summary

Puget Sound Energy (PSE) is installing a new powerhouse at its Lower Baker Development and will begin construction by the end of 2010. The powerhouse is scheduled to be operational by the end of 2013. PSE is pursuing a tax grant in lieu of the production tax credit, as discussed in Section 1603 of the American Recovery and Reinvestment Act of 2009. This document addresses the request for FERC certification that is a prerequisite for applying for the tax grant with the Department of the Treasury, and demonstrates that the installation of the proposed Unit 4 powerhouse will increase annual hydropower production by over 109,000 MWh or nearly 40%.

Historical energy production. The 1981-2002 average energy production at the Lower Baker Development was 365,540 MWh, as stated in the license (PSE, 2005). The hydroelectric analyses herein are based on the same five representative energy years that were used in the relicensing process: 1993, 1995, 1996, 2001, and 2002. These five years span a wide range of hydrologic conditions at the project and are given weights to reflect the frequency of similar years. The representative years have a weighted annual average of 362,153 MWh of generation, about 0.9% lower than the long-term average.

Modeling methodology. A newer version of HYDROPS, the hydroelectric operations model that was used during relicensing, was used for the analyses herein. Model calibration runs of the five representative years using the exact same flows as the historical record result in a weighted average of 376,739 MWh. This result is only about 4% higher than the historical generation for the same five representative years. PSE thus concluded that HYDROPS was capable of replicating historical operations. HYDROPS was then applied to the future license constraints as seen in Baker River Hydroelectric Project license settlement agreement article 106, aquatics table 1.

The model was run for each of the five representative years using two powerhouse configurations at the Lower Baker Development: (1) the existing Unit 3 equipped with a new synchronous bypass valve, and (2) the existing Unit 3 (no valve) plus a new Unit 4 with 1,500 cfs capacity and a bypass valve. Therefore a suite of ten runs was completed, all using the same daily historical flows that were used during model calibration.

Modeling results. HYDROPS runs show that the weighted generation at Lower Baker with Unit 3 alone drops from 376,739 MWh per year under pre-license conditions to 277,040 MWh per year once license restrictions take effect. When Unit 4 is included under future operating conditions, yearly generation increases to 386,520 MWh — an increase of 109,480 MWh. Most of the increase comes from two sources. First, the future minimum instream flow of either 1,000 or 1,200 cfs (depending on the season) is always being used for generation by Unit 4 except during outages. Unit 3 has a rough zone below 2,800 cfs, so generating at the minimum instream flow would result in severe cavitation and greatly decrease the unit's efficiency and effective lifespan. Therefore PSE does not generally run the unit below 2,800 cfs. The second source is increased generation during downramping. Unit 3 alone does not have the flexibility to generate the entire time it is downramping and must rely on spill for flows below 2,800 cfs, whereas with the addition of Unit 4, potentially long downramps can still result in significantly more generation as water is shifted from Unit 3 to Unit 4.

Conclusion. Installing Unit 4 at the Lower Baker Development will clearly result in major increases in generation after the post-license constraints have taken effect. This document shows that with the same set of water flow data, annual generation increases from 277,040 MWh without Unit 4 to 386,520 MWh with Unit 4 installed: a difference of 109,480 MWh or nearly 40%.

Introduction

Puget Sound Energy (PSE) is installing additional hydroelectric capacity at its Baker River Hydroelectric Project (the "Project"), Federal Energy Regulatory Commission (FERC) License No. 2150, and will begin construction by December 31, 2010. In accordance with Section 1603 of the American Recovery and Reinvestment Act of 2009 (ARRA), PSE is submitting the information herein for FERC certification before pursuing the "grants for specified renewable energy property in lieu of tax credits" for which the company qualifies due to the installation of additional hydroelectric capacity. Section IV, part H of the U.S. Treasury Department document "Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009" states that the FERC must certify the applicant's baseline and additional incremental energy production estimates for the proposed facility before application to the Treasury Department for the tax grant discussed in ARRA section 1603 (Treasury, 2010).

This report documents PSE's methods and results in estimating both the baseline and incremental energy production estimates associated with the installation of a single 30 MW turbine at Lower Baker Dam. It begins by discussing how the deadlines associated with the ARRA grants are going to be met. Then there is a description of the HYDROPS model used to determine the energy production with and without the additional powerhouse. Next is a discussion of the historical flows and generation at the Project as requested in "Instructions for Requesting Certification of Incremental Hydropower Production Pursuant to the Energy Policy Act of 2005" (FERC, 2007), along with an analysis of the model calibration. Finally, the results are presented for the two configurations during five different years which cover a wide range of hydrologic conditions.

General Description and Location of the Baker River Project

The Baker River Hydroelectric Project, owned and operated by Puget Sound Energy, Inc., is located on the Baker River in Skagit and Whatcom counties, Washington, north of and partially within the Town of Concrete. The Project consists of two developments: Lower Baker Development and Upper Baker Development.

The Lower Baker Development consists of a concrete arch dam 1.2 river miles upstream of the Baker River's confluence with the Skagit River (river mile [RM] 1.2), a 7-mile-long reservoir, a power tunnel, a single-unit powerhouse at RM 0.9, a fish barrier dam and trap at RM 0.6, a primary transmission line, and associated facilities. The Lower Baker Development was constructed between April 1924 and November 1925. The dam was raised 33 feet in 1927. In 1965, a landslide destroyed the three-unit powerhouse. Turbine generator Units 1 and 2 were abandoned as a result of the slide, and a new powerhouse structure was built for Unit 3, which was refurbished and reinstalled. Unit 3 returned to service in September 1968. The authorized capacity of the Lower Baker Development is presently 79,330 kW.

The Upper Baker Development consists of a concrete gravity dam at RM 9.35, an earthen dike, a 9-mile-long reservoir, a two-unit powerhouse, and associated facilities. The Upper Baker Development was constructed between June 1956 and October 1959. The authorized capacity of the Upper Baker Development is 90,700 kW.

Only Lower Baker Development is included in the analysis of incremental hydropower generation because no new generating facilities or upgrades are being proposed for the Upper Baker Development at the present time.

Proposed In-Service Date and other Key Dates

The proposed in-service date for the new 30 MW powerhouse below Lower Baker Dam (see figure 1) is December 31, 2013. Construction is scheduled to commence on December 15th, 2010, making the project eligible for "grants for specified renewable energy property in lieu of tax credits." To qualify, PSE must submit its application to the Treasury Department by October 1, 2011. The application must include the FERC's order certifying incremental hydropower generation for IRS section 45 production tax credit under section 1301(C) of the Energy Policy Act of 2005.

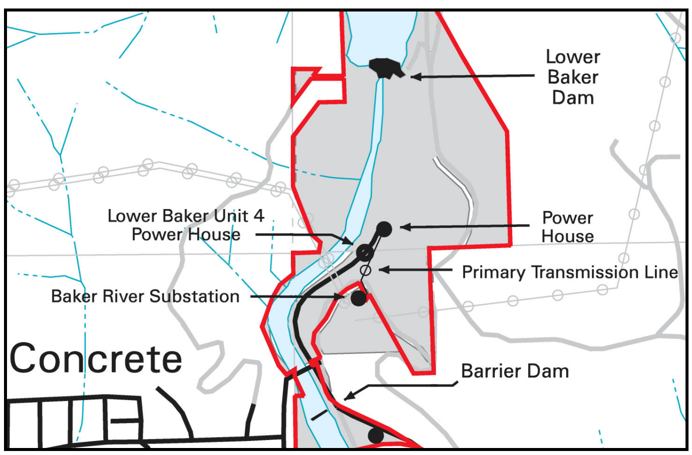

Figure 1. Location of proposed Unit 4 powerhouse.

HYDROPS Hydroelectric Operations Model

There is currently one unit at Lower Baker (Unit 3); the new powerhouse will include the installation of Unit 4. The HYDROPS model (Power Group Inc.) was used to determine the generation with and without the new unit at Lower Baker and to calibrate the model to reflect historical operation. This model was used extensively in the FERC relicensing process, and its use and results were approved by the FERC in the past.

The HYDROPS model maximizes the potential revenues from the Project while complying with the constraints imposed on the system by the Project's 2008 FERC license (the "license") and other operational parameters. Another major constraint is that under article 107(a) of the license, the Project must provide flood control to the U.S.

Army Corps of Engineers in accordance with their Water Control Manual (ACOE, 2000).

In the spring of 2010, the model was upgraded to more accurately calculate downramping, substitute a single 1,500 cfs turbine for two 750 cfs turbines, and update the output routine to more easily export information needed in the request for certification.

The model uses an “Engineering Module” which includes several characteristics of the system such as the unit capacity, rough zones, and efficiency curves, as well as reservoir maximum and minimum pools, tailwater curves, maximum capacity of penstocks, head losses in the penstocks, and more. Appendix A shows screen shots of the Engineering Module with the settings used in the current runs. While the module includes both units, Unit 4 is assigned a year-long outage during the runs that do not include the new powerhouse in its configuration. For all modeling purposes, this assignment eliminates Unit 4 from the optimization in those scenarios. Efficiency data for Unit 3 was based on a performance test report (American Hydro Corp, 2001). Efficiency data for Unit 4 was obtained from turbine vendors. Head losses through the system were computed by PSE staff, and include friction losses through tunnels and penstocks and minor losses associated with fittings and entrances.

The Engineering Module provides the information necessary to run the “Study Model”, where the user can design very specific scenarios that include operational constraints and other input parameters. Examples of these constraints include:

- Maximum and minimum lake levels for both Baker Lake and Lake Shannon.
- Maximum and minimum total releases as seen in the Baker River, in accordance with aquatics table 1 in settlement agreement article 106 of the license.
- Maximum and minimum powerhouse generation.
- Maximum and minimum powerhouse discharge.
- Maximum and minimum spill.
- Ramping rates, which in the current version was updated for river stage level changes on an hourly basis, based upon flows in the Skagit and Baker rivers and the stair-step function described in figures A and B of license settlement agreement article 106 that determines allowable downramping rates.
- Turbine outages for maintenance purposes.
- Monthly peak and off-peak prices.

Appendix B shows aquatics table 1 from settlement agreement article 106, along with its corresponding figures A and B. This supplemental information helps provide the context for the license constraints.

The model calculates the generation in each unit on an hourly basis, with efficiencies and unit flows. Lake levels, total releases, downramping, and other factors can also be analyzed on an hourly basis. These results are saved in an SQL Server 2005 database and can be directly exported from HYDROPS as text files. The actual optimization of the Project’s developmental value is solved by CPLEX 6.5, an IBM product.

The hydrologic input to the model is based upon the same five representative years (also known as “energy years” or EY) used in the license application. These years begin on

August 1st and end in July, and are named for the year they end in. The five representative years enable analysis of the full range of hydrologic conditions at the Baker River Project:

- 2001 – very dry
- 1993 – somewhat dry
- 1995 – average
- 2002 – somewhat wet
- 1996 – very wet

The methodology using the model to compare expected generation between adding a new powerhouse and 1,500 cfs bypass valve versus operating only the Lower Baker Unit 3 powerhouse with a new 1,500 cfs bypass valve is discussed in the "Methodology" section.

Historical Flows and Generation

Historical unregulated inflows are used in the HYDROPS model. An example of the hydrograph for both Upper and Lower Baker inflows is shown below in figure 2. Most of the inflow data is based on a daily timestep, except for the Skagit River above Concrete, which is hourly. The model uses an hourly timestep.

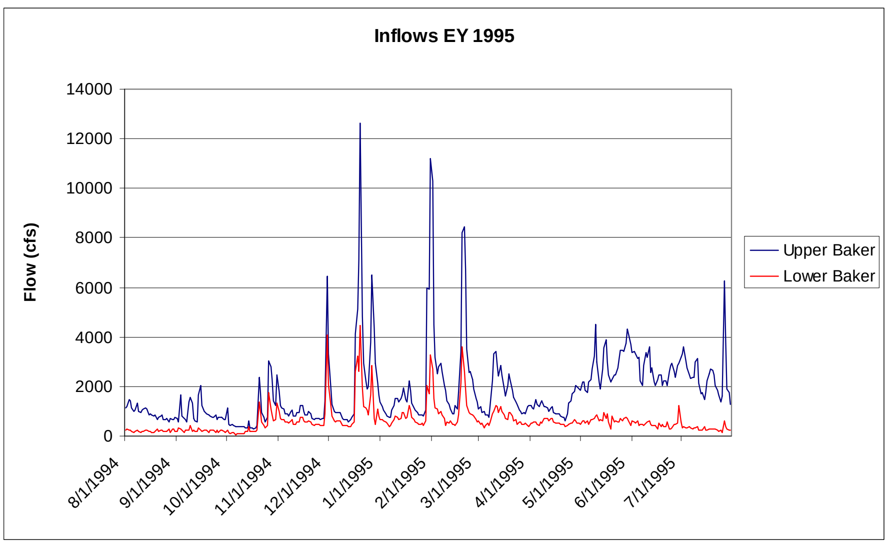

Figure 2. Inflow hydrograph for Upper Baker (blue) and Lower Baker (red) for the EY 1995.

PSE developed data sets that included daily flows for all five representative years for Upper Baker, Lower Baker, and the Skagit River above the confluence with Lower Baker. The inflows for the historical generation, the old PSE01 HYDROPS model runs used for calibration (see below), and every new scenario run used the same inflows, as required in the "Instructions for Requesting Certification of Incremental Hydropower Production Pursuant to the Energy Policy Act of 2005" (FERC, 2007) for their respective energy year.

Note that throughout this report there are times when information for Upper Baker and the Skagit River are provided for the sake of completeness. The Treasury Department's guidance document states that "the determination of incremental hydropower production shall not be based on any operational changes at such facility not directly associated with the efficiency improvements or additions of capacity" (Treasury, 2010). We take this to mean that any benefits from operational changes resulting from the new powerhouse do not count toward extra generation occurring upstream at Upper Baker Dam. Such benefits at Upper Baker are modest; almost all of the extra generation resulting from the installation of Unit 4 is at Lower Baker itself. The "Results" section shows this clearly.

Model Calibration

A series of HYDROPS model runs were developed during relicensing to serve as a basis for calibration with historical conditions. These runs herein are referred to by their names within the model itself, "PSE01". There are five of these runs, one for each representative year. The inputs of these runs reflect recent operating constraints in effect prior to relicensing the project.

Table 1 below displays the sums of the monthly historical generation reports for Lower Baker for each energy year, as well as the sum of resulting generated power from the PSE01 series. In order to create a more appropriate comparison, the generation for PSE01 is multiplied by 0.97 to take generator losses into account. The historical generation was taken at the generator itself, so this loss had already been counted in the historical data. The values are in megawatt-hours (MWh). The historical generation is not an appropriate baseline, since the FERC expects compliance with new minimum flows and ramping rates whether or not a new unit is added to the system.

Table 1. A comparison of Lower Baker historical generation data with HYDROPS model (PSE01) runs for each energy year. The values in the "Historical" and "PSE01" columns are in MWh.

Energy Year	Historical	PSE01	% Difference
1993	324,967	332,415	2.3
1995	371,261	383,251	3.2
1996	411,995	451,577	9.6
2001[a]	187,689	225,980	20.4
2002	467,228	465,715	-0.3
Additional Generation, Simple Average (MWh):	352,628	371,788	5.4
Additional Generation, Weighted Average[b] (MWh):	362,153	376,739	4.0

[a] 2001 was a somewhat unusual year due to major construction work and although partially reflected in the model input via an outage period, it proved more difficult to replicate in the model.
[b] The weighted average is described below in "Methodology."

The PSE01 runs are an outstanding proxy for the energy years 1993 (somewhat dry), 1995 (average), and 2002 (somewhat wet). The wettest (1996) and driest (2001) energy years are not as close, likely due to the model's tendency to optimize water use in comparison to the choices actually made in operations for those years. Other variables, such as forced outages, and other objectives, such as risk management during extreme hydrologic conditions like 1996 and 2001, also contribute to the percent differences seen in those two years. Overall, it is apparent that the model can reasonably reproduce the hydroelectric operations at the Project. The next step is to use the model to compare future operations with the license constraints for the two relevant configurations: with and without the installation of Unit 4 at the Lower Baker powerhouse.

As stated in the license application (PSE, 2005), the average annual energy production at the Lower Baker Development for the period 1981 through 2002 was 365,540 MWh. As shown in table 1, the weighted simulated energy generation for the five representative years is 376,739 MWh, or about 3% higher than the long-term average. However as shown in appendix C, flows for the slightly longer period of 1975 through 2002 are about 3.8% higher; thus the five representative years are reasonably consistent with a long period of record and would be expected to be slightly higher than for the period 1981 through 2002. Note that earlier generation records prior to 1981 are not directly comparable because a different flood operating protocol was in effect. The weighting factors were selected to reasonably reproduce the flow duration curve associated with the Project. Appendix C includes the memo developed during relicensing (LBG, 2003) that addresses the selection of five representative years.

Methodology

In the past, the results from the HYDROPS model were incorporated by FERC in both the environmental impact statement (FERC, 2006) and final license order (FERC, 2008) to characterize the expected generation from improvements at Lower Baker. The updated comparison for purposes of the ARRA tax grant reflects greater detail regarding the constraints of the new license than was simulated in the license application. The appropriate baseline configuration involves the current Unit 3 at Lower Baker, fitted with a 1,500 cfs synchronous bypass valve ("SBV" or "valve"). This SBV would be necessary to pass the minimum instream flows mandated by license settlement agreement article 106, aquatics table 1, in the absence of a new unit. These minimum instream flows of either 1,000 or 1,200 cfs (depending on the season) are considerably higher than the 80 cfs minimum flow in the previous license. The SBV would also be helpful for downramping purposes. However, because Unit 3 has a rough zone under 2,800 cfs, PSE would generally avoid generating under this flow during normal operations due to the damage that would result to the turbine. This means that whenever there are insufficient inflows or other conditions that discourage generation at 2,800 cfs or above, the minimum instream flows and water used for downramping would be spilled. This would waste a significant amount of water during the course of a year over the analyzed range of hydrologic conditions (see the following section, "Results"). The configuration associated with incremental generation includes the installation of Unit 4 fitted with a 1,500 cfs SBV[1], and the existing Unit 3 turbine. Unit 4 will have a best gate near 1,200 cfs, which matches the minimum instream flow throughout most of the year. Upramping Unit 4 while downramping Unit 3 will also significantly reduce the spill used during downramping periods.

For each of the five representative years, the model was run with the same inputs (including inflows), except for changing the configurations for (1) Unit 3 with SBV; and

[1] An SBV was proposed by PSE as detailed in the report "License Article 407 Flow Continutation Study, Baker River Hydroelectric Project, FERC No. P-2150" published in June 2010.

(2) Unit 3, plus Unit 4 with an SBV. The results and discussion of these runs are described in the next section.

Results

The first table of results shows the generation with and without the installation of a new powerhouse. The summary of the results is in table 2. Note that the generation in the current runs is multiplied by 0.97 to account for generator losses and thus be more comparable to historical data.

When the constraints of the license take effect, there is a significant decline in generation, as shown from the "Unit 3 with SBV" column. At Lower Baker, the weighted average annual generation of 376,739 MWh in the PSE01 series (from table 1) decreases to 277,040 MWh once the constraints of the license takes effect. The additional capacity of Unit 4 raises this up to a weighted annual average of 386,520 MWh, a difference of 109,480 MWh. A detailed breakdown of powerhouse flows for each energy year between the two scenarios (with and without Unit 4) explains how this large gap in incremental increase is achieved.

Table 2. Comparison of HYDROPS runs with the two configurations relevant to the tax grant in the ARRA, with and without the installation of the new powerhouse. All generation values are in MWh.

Energy Year	Unit 3 with SBV Generation	Unit 3 and Unit 4 with SBV Generation	Additional Generation	Increase (%)	Weight
1993	206,128	338,314	132,186	64.1	0.231
1995	291,670	393,700	102,029	35.0	0.462
1996	324,927	419,882	94,955	29.2	0.115
2001	147,054	290,957	143,903	97.9	0.077
2002	399,856	485,131	85,275	21.3	0.115
Simple Average	273,927	385,597	111,670		
Weighted Average	277,040	386,520	109,480		

As expected, the largest benefits are observed during dry years such as the drought year of 2001. There would be very little opportunity to generate with only Unit 3 and an SBV under such conditions, because the low inflow would only rarely provide the 2,800 cfs minimum generating flow needed for the normal operation of Unit 3. When Unit 4 is installed, at least the minimum instream flow can be used for generation during the entire year (except when Unit 4 is down for scheduled maintenance in the model). In wetter years, the opportunity to use both units at best or full gate affords significantly more generation as well.

The next several tables below (tables 3a through 3e) show the breakdown of powerhouse flows versus the power generated in each representative year for the Unit 4 and Unit 3-only scenarios, mostly in bins of 200 cfs. Flows under 900 cfs have a different bin because Unit 4 has a rough zone up to 900 cfs; therefore there is no generation under this flow rate. 1,501–2,799 cfs has a larger bin size because this falls between full gate of Unit 4 and within the rough zone of Unit 3. It is rare to generate in this range because cavitation damage to the turbine results from operating there. The final bin, 6,000-6,150 cfs, is smaller than the rest because 6,150 cfs is the maximum capacity of the combined tunnel that bifurcates to the Unit 3 and 4 tunnels. The number of hours is shown for each flow bin; this adds up to only 8,736 hours in a year because HYDROPS does optimization for exactly 52 weeks. This means that July 31st of each energy year is excluded. For leap years, July 30th and 31st are excluded. All of the generation values have been multiplied by 0.97 to stay consistent with the historical data.

Table 3a. Comparison of power generation with and without the new Unit 4 powerhouse for EY 1993.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	5,906	0	0	58	0	0	0
900-1099	0	0	0	1,290	924	22,778	22,778
1100-1299	0	0	0	3,667	1,123	80,368	80,368
1300-1500	0	0	0	1,057	1,488	31,164	31,164
1501-2799	9	2,785	486	9	2,786	486	0
2800-2999	87	2,923	4,954	89	2,908	5,022	68
3000-3199	296	3,114	18,073	318	3,112	19,402	1,329
3200-3399	185	3,313	12,084	210	3,313	13,725	1,640
3400-3599	1,211	3,519	83,402	1,107	3,518	76,753	-6,648
3600-3799	44	3,697	3,218	26	3,694	1,900	-1,318
3800-3999	99	3,891	7,664	94	3,890	7,285	-379
4000-4199	346	4,142	28,128	116	4,118	9,407	-18,721
4200-4399	12	4,335	1,007	21	4,272	1,757	750
4400-4599	37	4,486	3,189	17	4,471	1,458	-1,731
4600-4799	504	4,625	43,923	126	4,625	11,038	-32,885
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	24	5,150	2,384	2,384
5200-5399	0	0	0	19	5,285	1,930	1,930
5400-5599	0	0	0	466	5,482	49,064	49,064
5600-5799	0	0	0	0	0	0	0
5800-5999	0	0	0	19	5,811	2,054	2,054
6000-6150	0	0	0	3	6,125	340	340
Total	8,736		206,128	8,736		338,314	132,186
						% Increase	64.1

Table 3b. Comparison of power generation with and without the new Unit 4 powerhouse for EY 1995.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	4,742	0	0	150	0	0	0
900-1099	0	0	0	1,733	921	30,432	30,432
1100-1299	0	0	0	2,532	1,121	55,456	55,456
1300-1500	0	0	0	641	1,488	18,752	18,752
1501-2799	1	2,795	52	4	2,788	216	164
2800-2999	67	2,891	3,737	56	2,897	3,139	-598
3000-3199	435	3,089	26,164	250	3,092	15,045	-11,119
3200-3399	59	3,307	3,829	46	3,310	2,993	-835
3400-3599	1,851	3,519	125,105	1,907	3,519	130,136	5,031
3600-3799	42	3,663	3,025	39	3,689	2,850	-176
3800-3999	44	3,891	3,397	40	3,894	3,098	-299
4000-4199	653	4,143	52,751	195	4,138	15,904	-36,846
4200-4399	43	4,365	3,641	27	4,302	2,265	-1,376
4400-4599	11	4,453	935	26	4,480	2,233	1,298
4600-4799	788	4,625	69,034	194	4,625	17,004	-52,030
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	45	5,131	4,436	4,436
5200-5399	0	0	0	43	5,268	4,370	4,370
5400-5599	0	0	0	808	5,495	85,371	85,371
5600-5799	0	0	0	0	0	0	0
5800-5999	0	0	0	0	0	0	0
6000-6150	0	0	0	0	0	0	0
Total	8,736		291,670	8,736		393,700	102,029
						% Increase	35.0

Table 3c. Comparison of power generation with and without the new Unit 4 powerhouse for EY 1996.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	4,242	0	0	497	0	0	0
900-1099	0	0	0	793	923	13,908	13,908
1100-1299	0	0	0	2,475	1,122	54,493	54,493
1300-1500	0	0	0	758	1,490	22,268	22,268
1501-2799	18	2,785	938	2	2,793	109	-829
2800-2999	110	2,859	5,992	99	2,886	5,521	-470
3000-3199	900	3,121	53,846	903	3,120	54,055	210
3200-3399	90	3,271	5,801	109	3,281	7,053	1,252
3400-3599	1,509	3,518	103,593	1,435	3,518	99,333	-4,260
3600-3799	57	3,707	4,152	41	3,710	3,014	-1,138
3800-3999	45	3,931	3,466	50	3,902	3,882	416
4000-4199	729	4,143	58,451	206	4,138	16,818	-41,633
4200-4399	17	4,295	1,423	27	4,285	2,255	832
4400-4599	8	4,501	691	13	4,502	1,118	428
4600-4799	1,011	4,625	86,575	181	4,625	15,842	-70,733
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	106	5,194	10,522	10,522
5200-5399	0	0	0	24	5,279	2,438	2,438
5400-5599	0	0	0	623	5,494	65,613	65,613
5600-5799	0	0	0	167	5,794	17,978	17,978
5800-5999	0	0	0	0	0	0	0
6000-6150	0	0	0	227	6,125	23,663	23,663
Total	8,736		324,927	8,736		419,882	94,955
						% Increase	29.2

Table 3d. Comparison of power generation with and without the new Unit 4 powerhouse for EY 2001.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	6,606	0	0	157	0	0	0
900-1099	0	0	0	869	925	15,166	15,166
1100-1299	0	0	0	4,823	1,122	105,801	105,801
1300-1500	0	0	0	855	1,489	25,179	25,179
1501-2799	1	2,782	53	0	0	0	-53
2800-2999	69	2,904	3,859	86	2,899	4,847	988
3000-3199	686	3,117	41,139	701	3,120	41,813	674
3200-3399	88	3,300	5,661	61	3,298	3,972	-1,689
3400-3599	667	3,518	45,761	646	3,518	44,992	-768
3600-3799	57	3,743	4,155	33	3,702	2,420	-1,735
3800-3999	19	3,907	1,445	24	3,892	1,857	411
4000-4199	176	4,140	14,176	164	4,145	13,345	-830
4200-4399	9	4,295	728	21	4,306	1,762	1,034
4400-4599	58	4,580	4,800	14	4,519	1,207	-3,593
4600-4799	300	4,625	25,278	59	4,658	5,190	-20,088
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	13	5,138	1,285	1,285
5200-5399	0	0	0	42	5,247	4,238	4,238
5400-5599	0	0	0	149	5,513	15,747	15,747
5600-5799	0	0	0	0	0	0	0
5800-5999	0	0	0	1	5,928	110	110
6000-6150	0	0	0	18	6,125	2,026	2,026
Total	8,736		147,054	8,736		290,957	143,903
						% Increase	97.9

Table 3e. Comparison of power generation with and without the new Unit 4 powerhouse for EY 2002.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	3,090	0	0	63	0	0	0
900-1099	0	0	0	659	923	11,083	11,083
1100-1299	0	0	0	2,115	1,121	45,934	45,934
1300-1500	0	0	0	256	1,489	7,347	7,347
1501-2799	5	2,782	244	7	2,783	352	108
2800-2999	34	2,895	1,852	31	2,930	1,714	-138
3000-3199	756	3,120	41,186	791	3,118	43,227	2,041
3200-3399	19	3,293	1,223	48	3,313	3,067	1,844
3400-3599	3,039	3,520	204,016	3,268	3,520	219,424	15,407
3600-3799	188	3,749	13,820	24	3,734	1,771	-12,048
3800-3999	15	3,879	1,155	19	3,903	1,474	319
4000-4199	197	4,144	16,078	113	4,138	9,055	-7,023
4200-4399	64	4,342	5,392	25	4,349	2,098	-3,294
4400-4599	4	4,520	345	23	4,493	1,957	1,612
4600-4799	1,325	4,625	114,544	44	4,625	3,838	-110,706
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	22	5,149	2,172	2,172
5200-5399	0	0	0	26	5,290	2,642	2,642
5400-5599	0	0	0	1,025	5,507	108,011	108,011
5600-5799	0	0	0	1	5,605	104	104
5800-5999	0	0	0	1	5,886	110	110
6000-6150	0	0	0	175	6,125	19,749	19,749
Total	8,736		399,856	8,736		485,131	85,275
						% Increase	21.3

Note that the average flow in the 900-1,100 cfs bin is between 921 and 925 cfs, depending upon the energy year. The reader may wonder how the 1,000 cfs minimum instream flow is met during this time (this bin occurs mostly during the August 1st to October 20th time period; see aquatics table 1 in appendix B). There is 25 cfs of leakage through Unit 3, and 55 cfs of seepage through the Lower Baker Dam. This 80 cfs of non-generating flow, when added to the 921 to 925 cfs through Unit 4, meets the minimum instream flow during this season.

There are many hours during each of the representative years in the Unit 3 with SBV configuration where there is no generation at all. Unit 4 minimizes this potential waste of water. With Unit 4 installed, the weighted average of zero-generation hours in a year drops from 4,907 (over 56% of the year) to 159 (under 2% of the year). Many of the hours with less than 900 cfs in the Unit 3 and Unit 4 with SBV scenario are artifacts of the model and would not occur in real operations.

Conclusion

This document provides the information necessary for a request for certification from the FERC, as a prerequisite to a tax grant application due to the additional hydroelectric capacity being installed at the Lower Baker Dam. As shown in the "Historical Flows and Generation" section, the historical generation is closely reproduced by the calibration runs performed by the HYDROPS model. The model uses the same historical daily unregulated inflows in each run. Five representative years (1993, 1995, 1996, 2001, and 2002) are analyzed to account for a wide range of hydrologic conditions. Weights are applied to these years to reflect the likelihood of each year's conditions occurring.

A comparison of two future alternatives — with and without the installation of the new powerhouse — clearly shows that a significant increase in generation results from the addition of Unit 4. As shown in table 2, the weighted average annual generation without the installation of Unit 4 is 277,040 MWh. With Unit 4 installed, the generation increases to 386,520 MWh, an increase of 109,480 MWh or 40%. This comparison includes the constraints required for future operations as defined in aquatics table 1 in article 106 of the license. The large increases in generation from Unit 4 are mainly due to the rough zone that occurs in Unit 3 below 2,800 cfs. To avoid severe cavitation damage and therefore decreased efficiency and unit life, PSE will not generally run the turbine in this zone and would have to spill to meet minimum instream flow and other downramping requirements.

The installation of Unit 4 adds between approximately 85,000 and 144,000 MWh of generation, depending upon the representative year. The annual weighted average of additional generation attributable to the new powerhouse is 109,480 MWh. This translates to a weighted average increase of 40%.

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PSE, 2010. Calculations of head loss from intake to turbines at existing and proposed Lower Baker Dam powerhouses, March 2010. Bellevue, WA.

PSE, 2010. License Article 407 Flow Continutation Study, Baker River Hydroelectric Project, FERC No. P-2150, June 2010. Bellevue, WA.

Treasury (U.S. Department of the Treasury), 2010. Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009. Revised March 2010.

Appendix A: Engineering Input to Operations Model

This appendix shows screen shots of the Engineering Module, focusing on parameters related to Lower Baker. Similar information for Upper Baker is not included because it is not considered to count toward the additional generation for the tax grant.

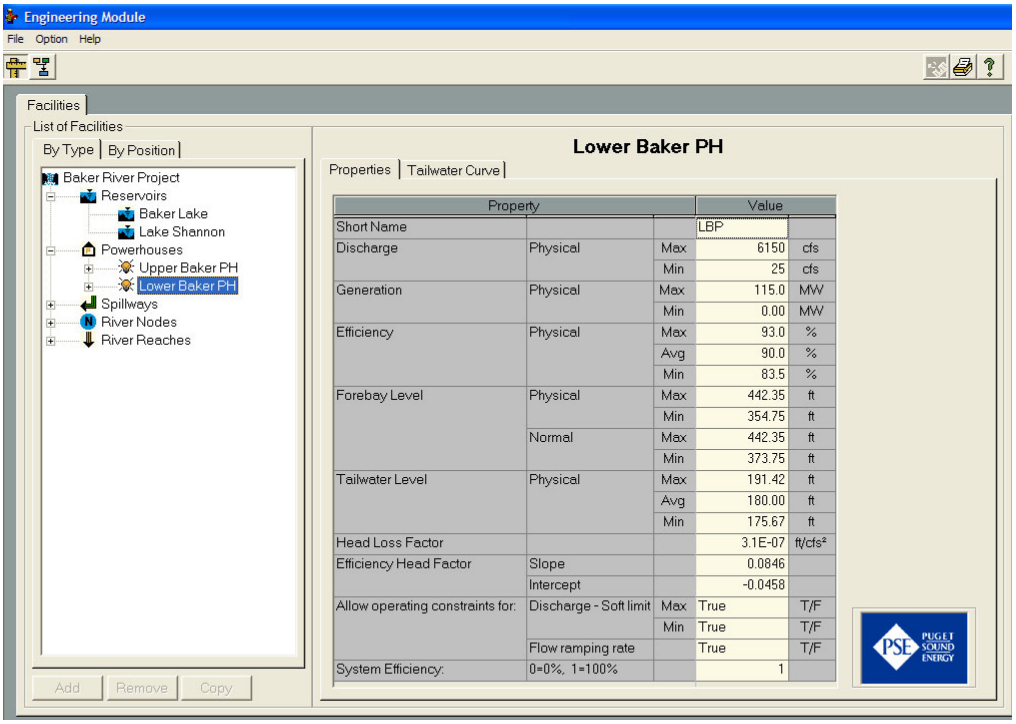


Figure A1. Screen shot of the Engineering Module, showing the total powerhouse parameters for Lower Baker.

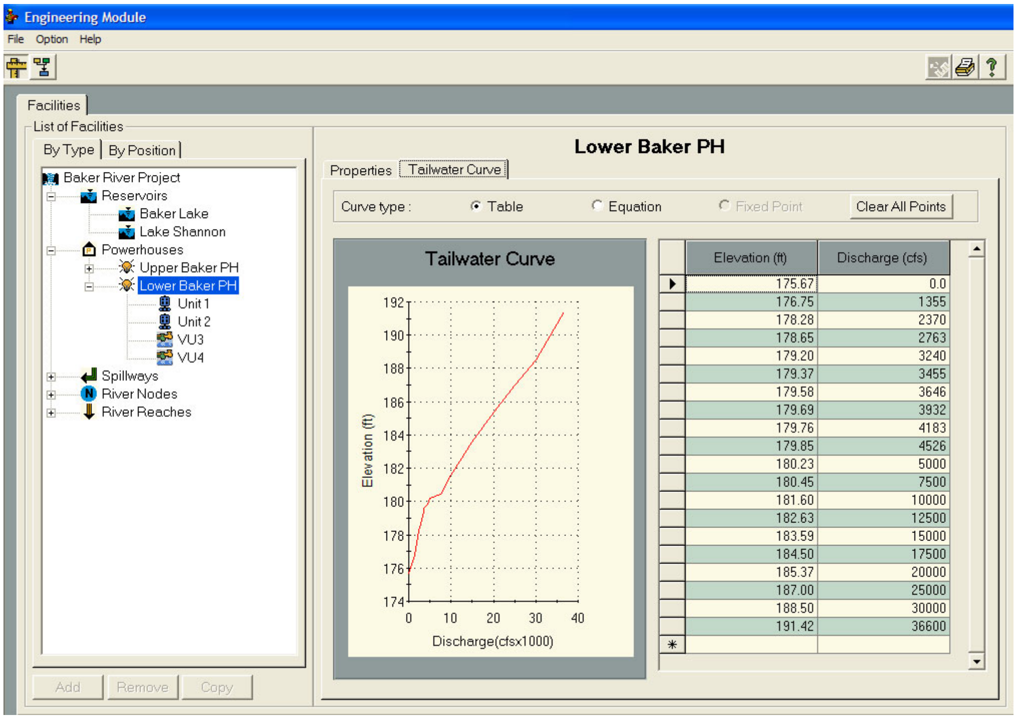


Figure A2. Tailwater curve for the Lower Baker powerhouse.

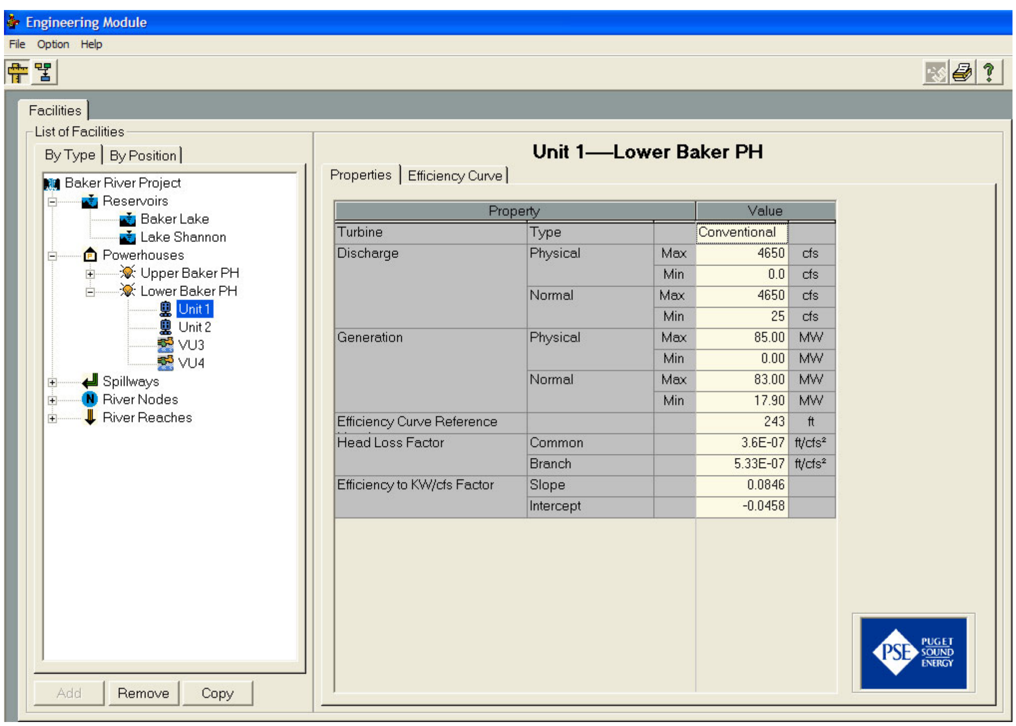
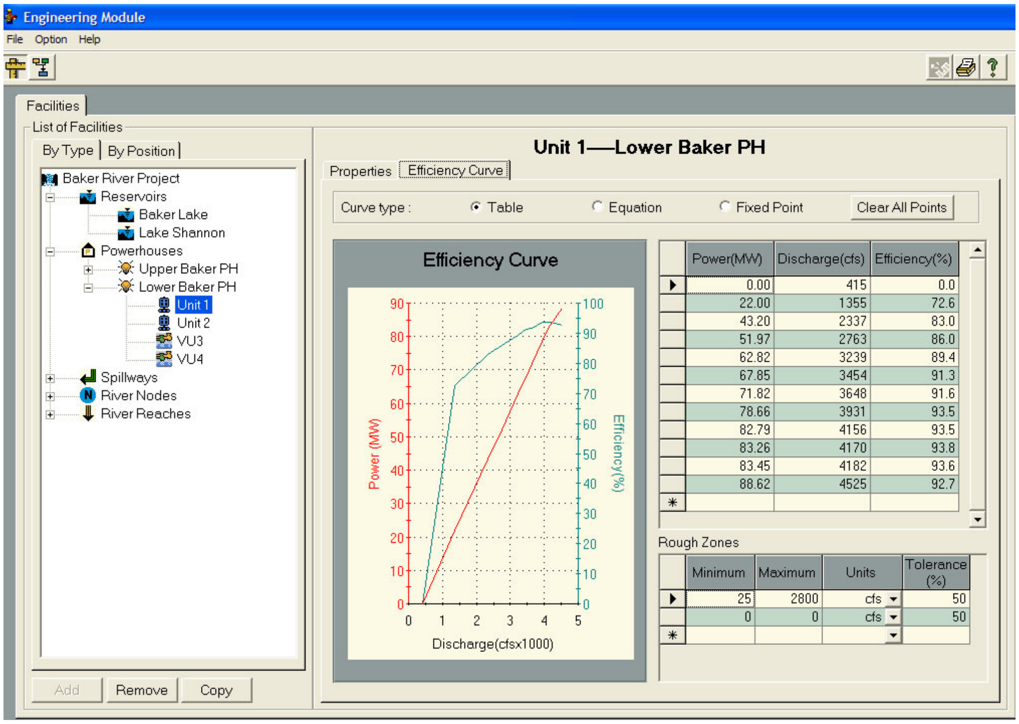


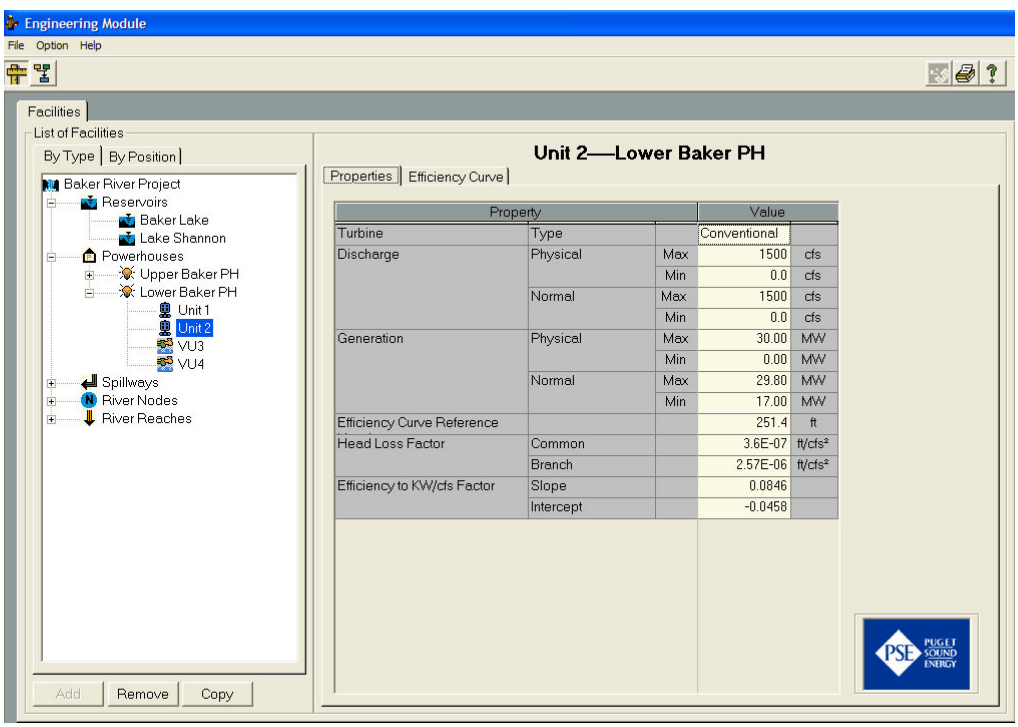
Figure A3. Parameters for Unit 3 at Lower Baker (Unit 3 is labeled Unit 1 in the program because it is the first unit at that powerhouse).



Power(MW)	Discharge(cfs)	Efficiency(%)
0.00	415	0.0
22.00	1355	72.6
43.20	2337	83.0
51.97	2763	86.0
62.82	3239	89.4
67.85	3454	91.3
71.82	3648	91.6
78.66	3931	93.5
82.79	4156	93.5
83.26	4170	93.8
83.45	4182	93.6
88.62	4525	92.7

Minimum	Maximum	Units	Tolerance (%)
25	2800	cfs	50
0	0	cfs	50

Figure A4. Efficiency curve and rough zone for Unit 3 at Lower Baker (Unit 3 is labeled Unit 1 in the program because it is the first unit at that powerhouse).



Property			Value	
Turbine	Type		Conventional	
Discharge	Physical	Max	1500	cfs
		Min	0.0	cfs
	Normal	Max	1500	cfs
		Min	0.0	cfs
Generation	Physical	Max	30.00	MW
		Min	0.00	MW
	Normal	Max	29.80	MW
		Min	17.00	MW
Efficiency Curve Reference			251.4	ft
Head Loss Factor	Common		3.6E-07	ft/cfs²
	Branch		2.57E-06	ft/cfs²
Efficiency to KW/cfs Factor	Slope		0.0846	
	Intercept		-0.0458	

Figure A5. Parameters for Unit 4 at Lower Baker (Unit 4 is labeled Unit 2 in the program because it is the second unit at that powerhouse).

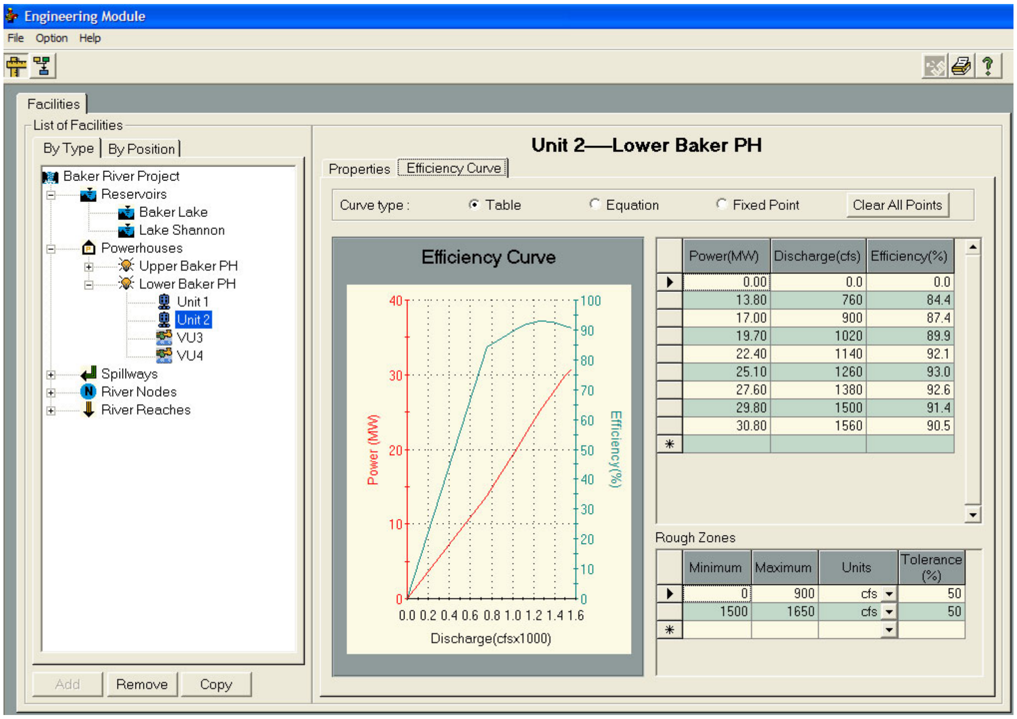


Figure A6. Efficiency curve and rough zones for Unit 4 at Lower Baker (Unit 4 is labeled Unit 2 in the program because it is the second unit at that powerhouse).

Note that while there is a 1500-1650 cfs rough zone in the module, the maximum capacity considered for these runs was 1500 cfs; so this rough zone did not factor into optimization.

Appendix B: License Constraints on Project Operation

This appendix shows aquatics table 1 and figures A and B from settlement agreement article 106 of the Baker River Project license. Most of the constraints input to the model are based on aquatics table 1. The allowable rate of downramping on the Baker River is deduced from the stair-step functions in figures A and B of license settlement agreement article 106.

Aquatics Table 1. Flows and reservoir elevations proposed for the Baker River Project, FERC No. 2150.

Lower Baker Development Engineering Module: Three turbines (one 4,100 cfs turbine, two 750-cfs turbines)							Upper Baker Development No changes to turbine configuration				
Period	Min. Instream Flow (cfs)	Max. Instream Flow (cfs) [1]	Downramping Rates [2]	Flood Control Storage (AF)	Max Pool Level (ft) (NAVD 88)	Min Pool Level (ft) (NAVD 88)	Period	Flood Control Storage (AF)	Max Pool [3] Level (ft) (NAVD 88)	Min Pool Level (ft) (NAVD 88)	Max Daily Pool Level Change
Aug 1-31	1,000	3,600	1-inch per hour day and night	No flood control requirement	442.35	404.75	Aug 1-31	No flood control requirement prior to 10/01	727.77	724.8	Max pool fluctuation ≤ 0.5 ft per rolling 24-hr period
Sep 1-3	1,000	3,600			442.35	404.75	Sep 3		727.77	724.8	
4-9	1,000	3,600			442.35	404.75	Sep 9		727.77	720.8	
10-30	1,000	3,200			442.35	404.75	Sep 30		727.77	718.8	No constraints on max daily pool level changes
Oct 1-7	1,000	3,200 [1]			442.35	389	Oct 7	Gradual drawdown to 74,000 AF by 11/15	727.11 [4]	713.8	
8-15	1,000	3,200 [1]			442.35	389	Oct 15		726.23 [4]	685	
16-20	1,000	3,200 [1]			442.35	389	Oct 20		725.68 [4]	685	
21-31	1,200	3,600 [1]			442.35	389	Oct 31		724.47 [4]	685	
Nov 1-15	1,200	3,600 [1]	2-inches per hour day and night		442.35	389	Nov 14		712.42 [4]	685	
16-30	1,200	3,600 [1]			442.35	389	Nov 15-30	74,000 AF 11/15 to 03/01	711.56	685	
Dec 1-31	1,200	3,600 [1]			442.35	389	Dec 1-31		711.56	685	
Jan 1-31	1,200	5,600			442.35	389	Jan 1-31		711.56	685	
Feb 1-15	1,200	5,600			442.35	389	Feb 1-15		711.56	685	
16-28	1,200	5,600	0 inches per hour day and 2 inches per hour night		442.35	389	16-28		711.56	685	
Mar 1-31	1,200	5,600			442.35	389	Mar 1-31	Gradual refill	718	685	
Apr 1-30	1,200	3,600			442.35	389	Apr 1-30	No flood control requirement after 04/01	718	685	
May 1-8	1,200	3,600			442.35	389	May 1-8		727.77	685	
9-14	1,200	3,600			442.35	389	9-14		727.77	713.8	
15-22	1,200	3,600			442.35	389	15-22		727.77	718.8	
23-31	1,200	3,600			442.35	389	23-31		727.77	724.8	Max pool fluctuation ≤ 0.5 ft per rolling 24-hr period
Jun 1-15	1,200	5,600			442.35	404.75	Jun 1-15		727.77	724.8	
16-30	1,200	5,600	1-inch /hour day and night		442.35	404.75	16-30		727.77	724.8	
Jul 1-31	1,200	5,600			442.35	404.75	Jul 1-31		727.77	724.8	

(1) Maximum release constraints eliminated when Baker Lake inflow > 10 % monthly exceedance flow OR Skagit River above the Baker River confluence > 24,000 cfs October through December.

(2) Downramping rates measured at the Baker River at Concrete, but based on stage changes observed at Transect 1 on the mainstem Skagit River below the Baker River confluence (RM 56.5).

(3) Maximum elevation unless otherwise directed by the District Engineer (Corps) during Flood Season.

No minimum flow requirements.
No maximum instream flow constraint.
No downramping limitations for environmental interests.
(4) Daily reservoir elevations between October 1, November 1, and November 15 shall be at or below straight lines drawn between 727.77 and 724.47 and between 724.47 and 711.56 for those respective dates with a gradual refill after March 1.

NOTE: All elevations are referenced to NAVD 88. Operations in effect for all years (no special dry year conditions)

Figure B1. Aquatics table 1 from settlement agreement article 106 of the license.

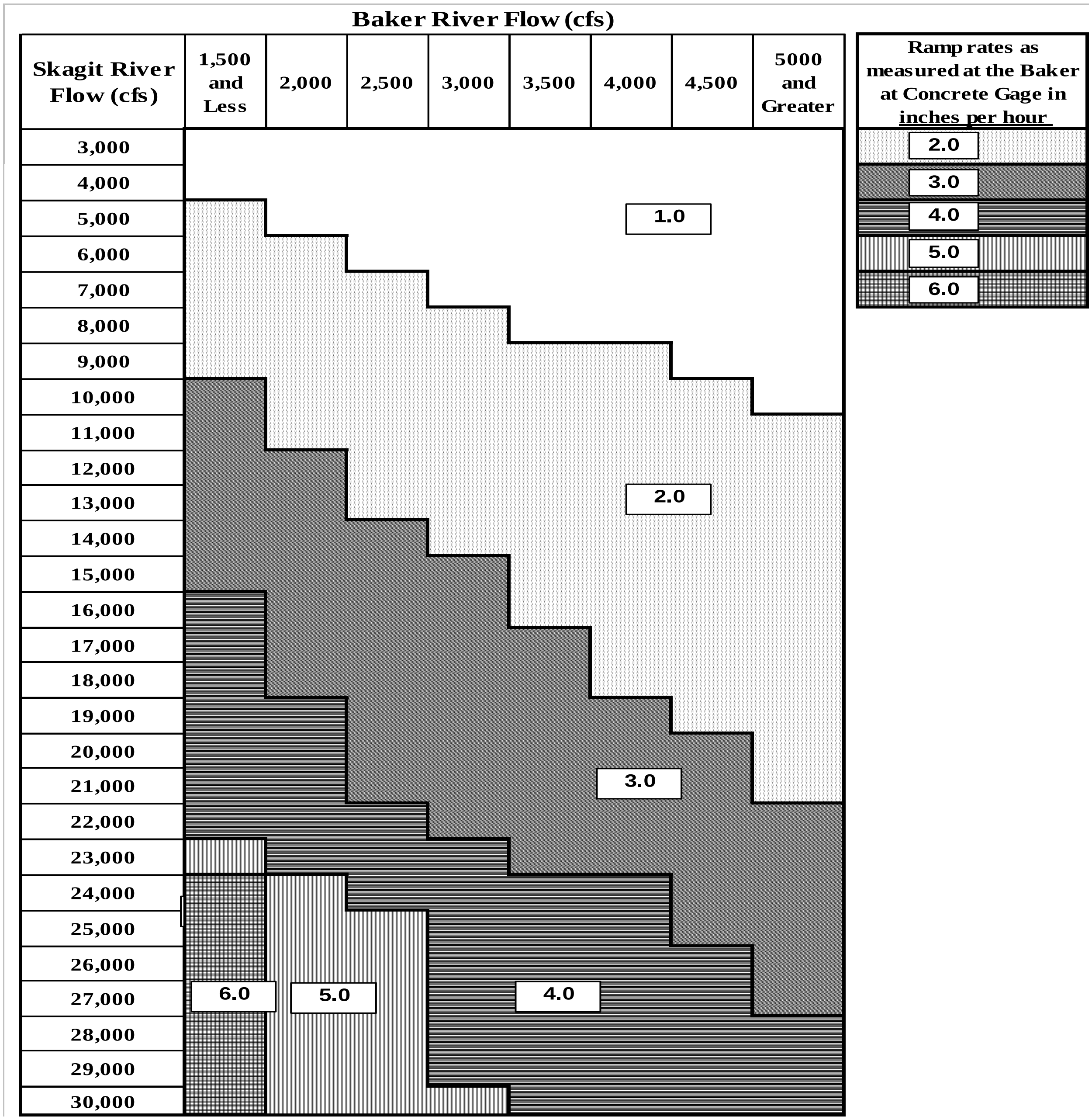


Figure B2. Aquatics Ramping Rate Figure A. Relationship between flows in the Baker River and Skagit River (Transect 1/Dallas Gage) and resulting in ramping schedule for the Baker River Project as measured at the Baker River at Concrete Gage to affect the Skagit River for seasons requiring 1 inch per hour.

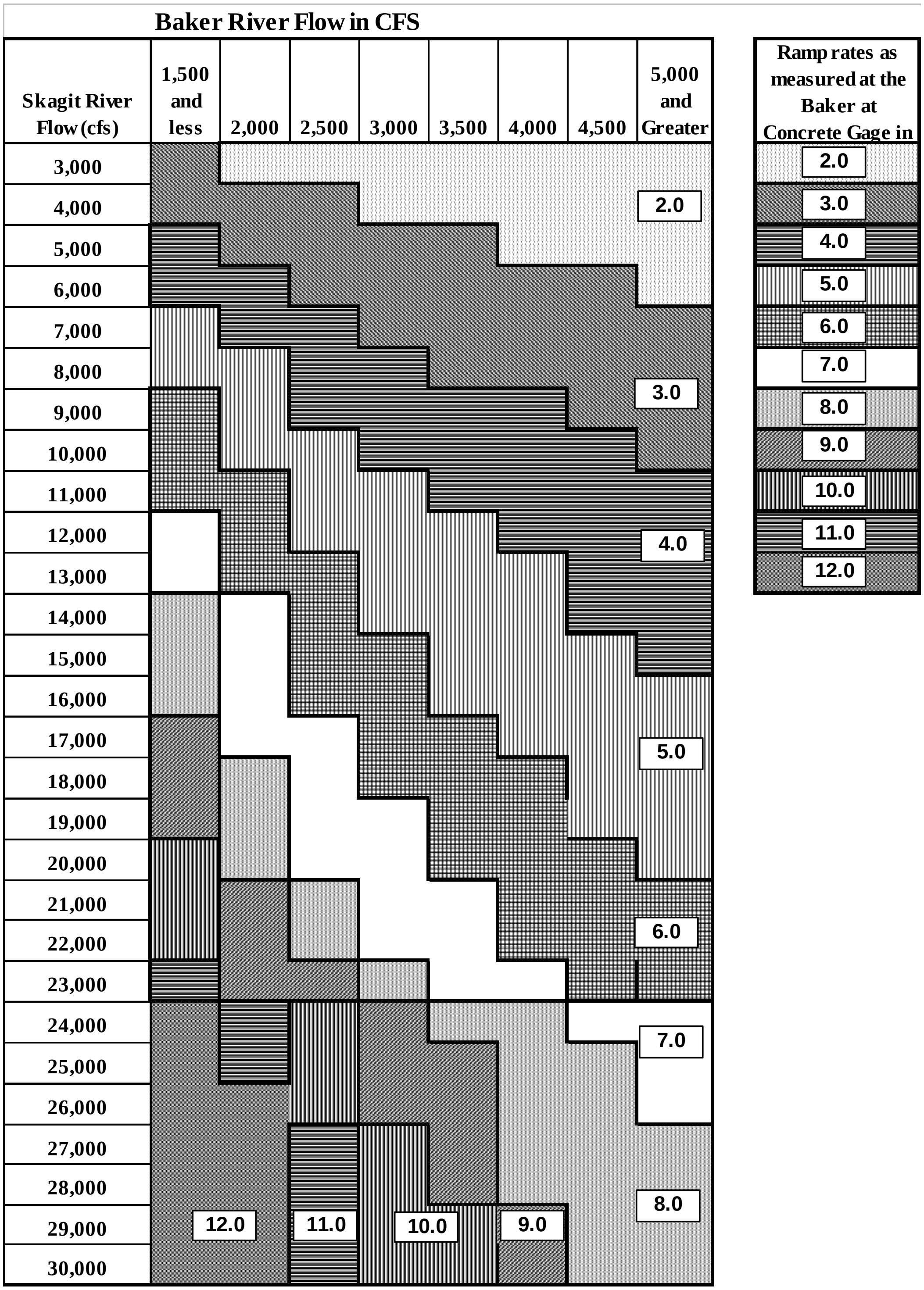


Figure B3. Aquatics Ramping Rate Figure B. Relationship between flows in the Baker River and Skagit River (Transect 1/Dallas Gage) and resulting in ramping schedule for the Baker River Project as measured at the Baker River at Concrete Gage to affect the Skagit River for seasons requiring 2 inch per hour.

Appendix C: Five Representative Years

This appendix excerpts a memo addressing the five representative years used in the hourly modeling of the baseline and incremental generation associated with the proposed Lower Baker Unit 4 Powerhouse.

SELECTION OF FIVE REPRESENTATIVE YEARS FOR INITIAL EVALUATION OF PROJECT ALTERNATIVES

Prepared for July 11, 2003 TST Meeting

By Mark Killgore (Louis Berger Group) with Review and Input by Paul Wetherbee (PSE) and Phil Hilgert (R2 Consultants)

Objective: The HYDROPS model requires approximately 30 minutes to complete both a long-term and short-term analysis for one year assuming no debugging is required. If spawning and incubation periods are set in the model, two or more iterations are required and the run time increases to one-hour per year or more per scenario. For NEPA evaluation we must run both recent conditions and any proposed alternative, hence, at a minimum, at least five hours per five year run is required and this could expand to 10 hours if multiple spawning periods are required. Therefore, in order to evaluate numerous proposals and conduct preliminary evaluation for the fall preliminary draft Environmental Assessment we selected five representative years based on total unregulated inflow into Lake Shannon (Lower Baker).

Basis for Selecting the Representative Years: Each year at the Baker Project is operationally distinct and not contingent on the previous year's storage except perhaps in an unusually extreme drought. Four of the representative years were selected for their value in examining a variety of hydrological conditions that are biologically driven. R2 Resource Consultants' June 6, 2003 memo to Paul Wetherbee summarizes the biological basis for why we selected Energy Years 1993, 1995, 1996 and 2001. Energy Years are defined as August 1 of the previous year till July 31 of the Energy Year (since the 7 months of the Energy Year constitute the majority of months).

We selected one additional year to produce a 5 year period of record that closely mimicked the long-term record available for Energy Years 1976 through 2002. The year best suited to this purpose was Energy Year 2002. Tables 1 and 2 at the end of this memo shows how the five selected years (and the four years without 2002) compare to each other and the longer period of record. Overall these five years result in an average flow that is 97% of the long-term average (2,538 cfs vs. 2,637 cfs). We also looked at five periods within the year including August, September and October (drawdown season), November through February (flood control season), March through May (primary refill season) and June and July (early summer). We chose not to combine August with June and July since they are separated by so many months in an energy year.

The three summer months were slightly drier than normal (about 88%), however the most altered months were within 99% to 100% of normal.

Table 3 provides an ascending order sort of each of the five periods and highlights in different colors the Energy Years selected for further evaluation. Bear in mind that the calendar year for August through December would be one less than the energy year. Notice how certain periods within any given Energy Year may be different than the overall hydrologic characterization for the year. This is a normal feature of Northwest hydrology. The wet season from November through March and subsequent spring snowmelt tends to dominate the overall character of the year. We have characterized the five energy years as follows:

- 1993 somewhat dry
- 1995 average
- 1996 very wet
- 2001 very dry
- 2002 somewhat wet.

Notice for example how August of Energy Year 2001 (August 2000) is rather normal where as the remaining periods all rank 5 or lower out of 27 Energy Years.

Chart 1 (Flow Duration Curve Baker River Unregulated) is a comparison of the daily flow duration curves for both the five year representative record and the 1976-2002 Energy Years long-term record. The overall trend is quite consistent although flows in the 15% to 50% exceedance range are about 150 to 200 cfs lower in the five representative years. At 50% exceedance this amounts to about 7.5%.

The next two sheets ("Chart 2. Flow Duration Curve Baker River Unregulated Sep-Nov" and "Chart 3. Flow Duration Curve Baker River Unregulated Mar-May") look at two of the most critical periods (September through November drawdown and March through May refill). The flow duration curves for both these periods provide an excellent match.

Conclusions: We conclude that the five selected representative Energy Years (1993, 1995, 1996, 2001 and 2002) are adequate to perform HYDROPs screening studies of potential alternatives versus recent conditions. The unregulated inflows span a full range of hydrologic conditions and are reasonably indicative of the type of variability that one might encounter using a longer period of record.

Table 1. Summary of Average Period Flows for Representative Years Vs. 1976-2002 Energy Years

All flows in cfs

Energy Year	All Months	Aug	Sep-Nov	Dec-Feb	Mar-May	Jun-Jul
1993	2,172	1,492	1,900	1,336	3,089	2,771
1995	2,464	1,142	1,451	3,530	2,549	2,949
1996	3,118	1,815	4,163	3,456	2,482	2,679
2001	1,868	1,974	1,653	1,283	2,148	2,575
2002	3,069	2,246	2,635	2,895	2,836	4,739
	Energy Year	Aug	Sep-Nov	Dec-Feb	Mar-May	Jun-Jul
Four Years	2,406	1,606	2,292	2,401	2,567	2,743
Five Years	2,538	1,734	2,360	2,500	2,621	3,143
1976-2002	2,627	1,966	2,349	2,501	2,648	3,572

Table 2. Percentage of Rep. Years Flow of 1976-2002 flow

Somewhat Dry	1993	82.67%	75.89%	80.90%	53.41%	116.63%	77.57%
Normal	1995	93.82%	58.08%	61.75%	141.13%	96.26%	82.54%
Very Wet	1996	118.72%	92.29%	177.22%	138.18%	93.70%	74.99%
Very Dry	2001	71.11%	100.42%	70.35%	51.31%	81.09%	72.08%
New Year	2002	116.82%	114.25%	112.18%	115.74%	107.09%	132.66%
Four Years		91.58%	81.67%	97.56%	96.01%	96.92%	76.80%
Five Years		96.63%	88.19%	100.48%	99.96%	98.95%	87.97%

Table 3. Sorted Summary of Selected Representative Energy Years Compared to 1976-2002 Energy Years

Energy Year	Aug	Energy Year	Sep-Nov	Energy Year	Dec-Feb	Energy Year	Mar-May	Energy Year	Jun-Jul	Energy Year	All Mos.
1995	1142	1988	1063	1979	1089	1978	2084	1992	2214	2001	1868
1988	1250	1994	1171	1985	1244	1977	2113	2001	2575	1979	2132
1999	1360	1995	1451	2001	1283	2001	2148	1987	2649	1993	2172
1997	1426	1980	1513	1993	1336	1982	2163	1977	2658	1977	2183
1994	1464	2001	1653	1988	1705	1998	2352	1996	2679	1988	2231
1986	1487	1977	1740	1989	1893	1981	2378	1994	2694	1994	2266
1980	1489	1992	1884	1977	1932	1992	2413	1993	2771	1985	2330
1993	1492	1993	1900	1987	2050	1976	2419	1979	2889	1978	2382
1981	1510	1983	1921	2000	2089	1999	2430	1986	2937	1992	2423
1989	1609	1999	1964	1998	2280	1984	2437	1995	2949	1987	2427
1987	1699	1987	2100	1990	2464	1983	2467	1998	3034	1995	2464
1982	1721	1979	2108	1994	2489	1996	2482	1978	3045	1989	2499
1996	1815	1978	2126	1986	2503	1991	2521	1981	3276	1986	2592
1991	1824	1985	2275	1978	2561	1985	2528	1989	3354	1998	2598
1990	1839	1997	2406	1982	2646	1995	2549	1988	3684	1983	2723
2001	1974	1982	2460	1984	2687	2000	2609	1990	3777	1984	2743
1979	1998	1984	2580	1983	2773	1979	2718	1985	3814	1990	2787
1984	2030	1989	2586	2002	2895	1990	2719	1984	3890	1982	2792
1998	2099	1981	2633	1999	2901	1989	2740	1991	3928	1999	2804
1985	2133	1986	2635	1992	2902	1986	2782	2000	4231	1981	2816
1978	2190	2002	2635	1997	2928	2002	2836	1976	4338	1980	2921
2002	2246	1990	2836	1991	3320	1980	2959	1983	4401	2000	3001
1976	2300	1998	3040	1996	3456	1993	3089	2002	4739	2002	3069
1983	2393	2000	3118	1980	3464	1994	3118	1997	4832	1996	3118
1992	3036	1976	3250	1976	3502	1987	3217	1980	4884	1976	3205
1977	3484	1996	4163	1995	3530	1988	3275	1982	4997	1997	3249
2000	4076	1991	4214	1981	3587	1997	3961	1999	5214	1991	3316
Five Rep. Years Simple Avg.	1734		2360		2500		2621		3143		2538
Energy Year 76-02 Simple Avg.	1966		2349		2500		2648		3572		2634

Note minor differences between simple average and database averages due to leap year.

Chart 1. Flow Duration Curve Baker River Concrete Unregulated

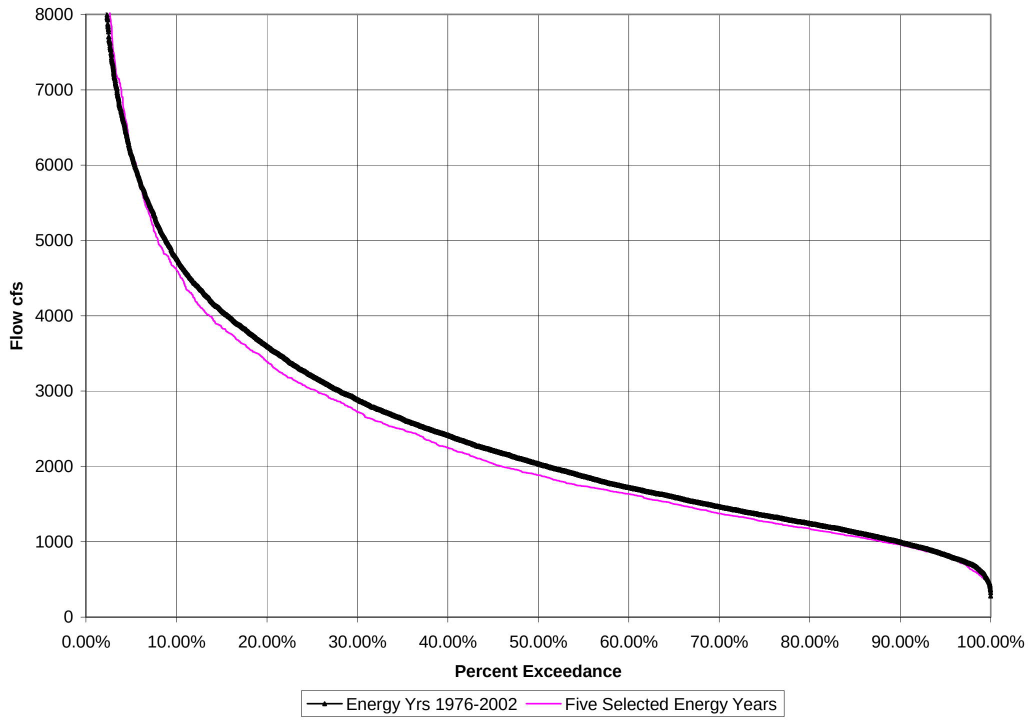


Chart 2. Flow Duration Curve Baker River Concrete Unregulated Sep-Nov

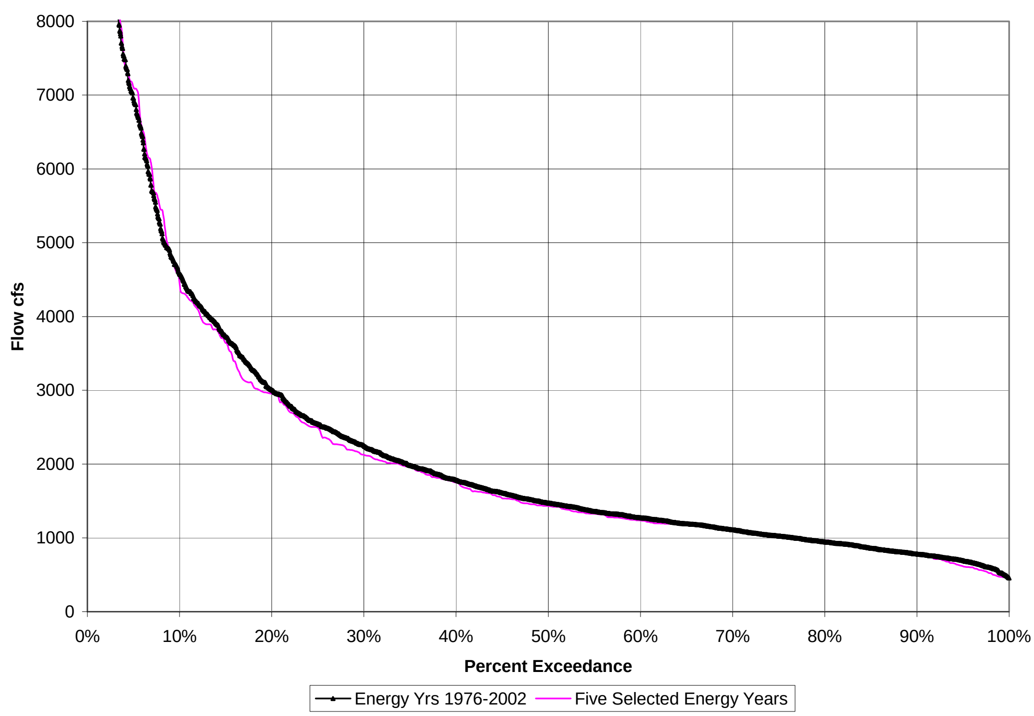


Chart 3. Flow Duration Curve Baker River Concrete Unregulated Mar-May