Black Canyon Hydroelectric Project
FERC Project No. P-14110
Hydropower Potential & Project Economics Study Report
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Executive Summary

This report presents the results of the study methodology prescribed in the Revised Hydropower Potential & Project Economics Study Plan (Study Plan) (Black Canyon 2012). The three principal objectives of the study include estimating (1) the alternative cost of power in the region; (2) the construction cost for development of the project alternatives; (3) the best utilization of available river flow and the hydraulic capacity of the facility; and (4) the estimated loss of revenue for each of the Protection, Mitigation, and Enhancement (PM&E) measures, (18 CFR 5.18(b)).

The study will use a proprietary feasibility model (Model) developed to evaluate hydroelectric projects. The Model inputs include streamflow, instream flow requirements, ramping rate restrictions, facility parameters (gross head, equipment efficiencies, and capacity), construction cost estimates, and power market trends.

Preliminary results indicate a facility capacity of 800 cfs will maximize the generation potential of the plant. The estimated development cost for the facility is approximately $66 million, or $2,640 per MW of installed capacity, which would require a starting energy rate of $70/MWh, with an annual escalation of 2.5%. This compares well with the expected cost of energy when the Project comes on-line, which is expected in 2019. The estimated annual operations and maintenance cost for the facility is approximately $951,000/year. The estimated annual cost of instream flow requirements as a PM&E measure range from $264,480 to $1,082,320 with instream flow requirements of 50 and 100 cfs respectively. The estimated annual cost of ramping rate restrictions as a PM&E measure cannot be estimated at this time as no ramping rate restrictions have been proposed for the Project. The estimated annual cost of recreational flows as a PM&E measure will be directly impacted by any ramping rate restrictions imposed on the Project. A preliminary estimate of the partial cost of lost generation to provide recreational flows, assuming that there are no ramping rate requirements, providing recreational flows 2 days per week when achievable (weekends), ranges from $326,240 to $647,360 with recreational flow ranges between 350-500 and 350-1,100 cfs respectively.

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1 INTRODUCTION

1.1 PURPOSE

Black Canyon Hydro, LLC (BCH) filed a Notice of Intent (NOI) and the associated Pre-Application Document (PAD) to commence the FERC Integrated Licensing Process on March 27, 2012. In response to the subsequent study requests filed by FERC staff and other stakeholders, on January 7, 2013 BCH submitted relevant resource study plans in accordance with 18 CFR 5.11. This report presents the results of the study methodology prescribed in the Revised Hydropower Potential & Project Economics Study Plan (Study Plan) (Black Canyon 2012).

The approved Economics Study Plan describes the purpose, objectives, approach, and methods for the evaluation of the economics of the proposed Black Canyon Hydroelectric Project. The Economics Study includes a comprehensive financial analysis to support Black Canyon LLC's license application to FERC, including (1) the alternative cost of power in the region; (2) the construction cost for development of the project alternatives; (3) generation estimates for alternative turbine configurations; and (4) the estimated loss of revenue for each of the Protection, Mitigation, and Enhancement (PM&E) measures, (18 CFR 5.18(b)).

1.2 STUDY GOALS AND OBJECTIVES

In accordance with 18 CFR §5.11(d)(1), this section describes the goals and objectives of this study and the information to be obtained. The goal of the study is to provide cost information, financial metrics, and generation estimates to support a new FERC license application for future operation of the Project;

The study has three principal objectives:

1. Determine whether the hydraulic capacity of the proposed turbine generating units (or turbine generating units with a different hydraulic capacity) would best utilize the available river flow and any instream flow releases to the Project Reach; and.
2. Compare the cost of the proposed project (i.e., capital and annual operation and maintenance (O&M) costs) and the likely cost of alternative power in the region.
3. Determine the estimated cost of lost generation for PME measures related to: (1) minimum flow releases in the Project Reach for aquatic resources; (2) ramping

rate restrictions; and (3) any operational changes that may impact flow in the project reach for recreation.

1.3 BACKGROUND

BCH ultimately plans to file an application for an original license for the Black Canyon Hydroelectric Project (Project), FERC Project Number P-14110, and associated facilities on the North Fork Snoqualmie River (North Fork), approximately 4-miles northeast of North Bend in King County, Washington. The Project has a proposed generation capacity of 25 megawatts (MW) and would be located predominately on private lands. The Project would operate in run-of-river mode. The combined maximum hydraulic capacity of the Project turbines would be 900 cubic feet per second (cfs). The Project would divert water from a 2.7-mile-section of the North Fork, Figure 1.

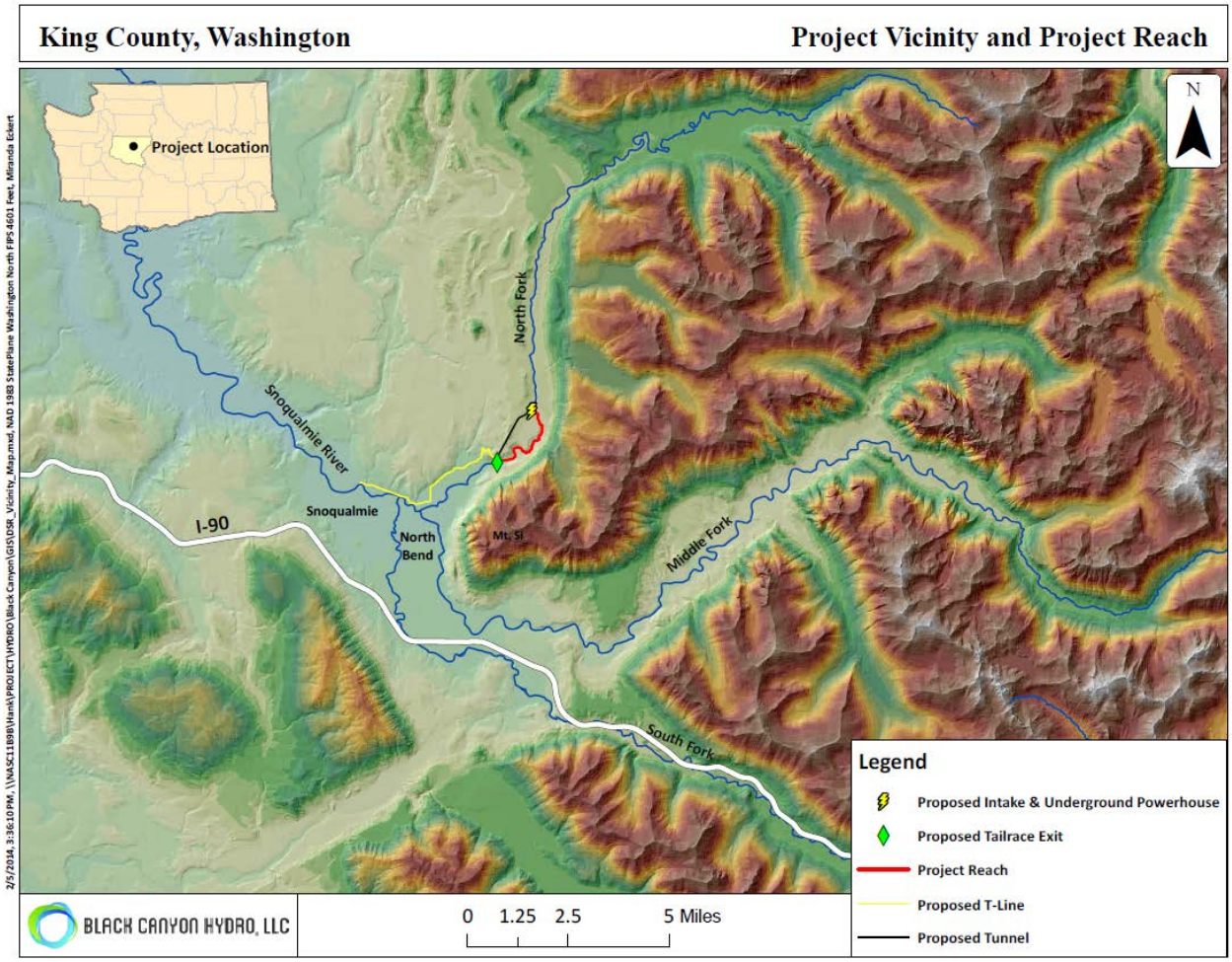


Figure 1 - Project vicinity, principal feature locations, and reach.

Intake

The following description of intake features reflects an evolution in Project design since the filing of the Pre-Application Document (PAD) through scoping, stakeholder comment, and study results. As a result of completing relevant studies, two possible design alternatives have been developed for the intake. These Alternatives are called Alternative C and D. Both alternatives involve bulk water screening located at approximately RM 5.3, on the same river bend and point-bar as Alternative A. Alternative C uses a vertical plate screening system, and Alternative D uses a horizontal plate screening system.

Both alternatives would have a (1) control sill to control the normal water surface elevation and maintain a consistent river bed elevation for a side channel bulk-water intake. The control sill would consist of a concrete weir with boulders inset on the surface over top of a sheet pile cutoff wall to capture hyporheic flow. The sill would be at the newly established grade of the river bed and would allow uninterrupted flow through a natural looking re-profiled river as a roughened channel series of step pools, riffles, and boulder weirs. (2) An intake structure with a coarse trashrack, jib crane, and radial gate with sluiceway located on the east bank of the river. Diverted water would be conveyed through; (3) an open channel to a; (4) head gate control structure and into a; (5) fish and debris screening structure. (6) Fish and debris would be screened and bypassed back into the river. Screened water would then flow through a power conduit to the underground powerhouse. (7) Access to the intake site would use an existing logging road and approximately 400 feet of new roadway extending to the intake site.

Powerhouse

The powerhouse location would be located underground beneath the selected intake site. This would include a (1) 450-feet tall, 30-foot diameter vertical shaft to allow space for the power penstock(s), elevator, stairs, ducting, mechanical, and electrical chases. Screened water from the intake screen system would be delivered down a (2) vertical power penstock(s) to the powerhouse. The powerhouse would (3) use four Pelton Turbines each rated at 6.25-MW, as well as appurtenant facilities. The (4) powerhouse substation and (5) elevator building would be located near the intake structure.

Tailrace

The tailrace will be an approximately (1) 8,600 foot long 12 foot diameter tunnel, and is anticipated to be constructed primarily in bedrock. The tailrace water return to the North

Fork would be located at approximately the same location as proposed in the PAD at approximately RM 2.6.

Transmission

Transmission would consist of a 34.5-kilovolt (kV) underground transmission line and overhead transmission that transmits project power to the regional grid. The transmission line would be sited predominantly on an existing power line corridor. The transmission line would originate at the powerhouse substation located at the intake site at RM 5.3. Subsurface transmission would follow the vertical shaft to the underground powerhouse, and down the 1.6 mile long tunnel. After exiting the tunnel the transmission would travel underground 1.0 miles on new and existing roads then 4.2 miles as 34.5- kV overhead transmission line predominantly following an existing power line corridor to the point of interconnection. The point of interconnection is located at an existing overhead transmission line near the intersection of 396th Drive SE and SE Reinig Road approximately 0.4 miles from the City of Snoqualmie. A new switch and substation would be added at the point of interconnection to transform voltage from 34.5-kV to 115-kV.

1.3.1 Updated Average Monthly Generation Estimates

The monthly energy generation estimates presented in the PAD were based on streamflow measured upstream of the proposed intake site at USGS Stream Gauge No. 12142000. An update was included in the Revised Hydropower Potential and Project Economics Study Plan representative of the generation from flows available at the intake location. Generation estimates have subsequently been revised to reflect stream monitoring data collected over the 2013 water year at he proposed intake location, Table 1. Generation estimates presented in Table 1 assumed a year round instream flow requirement of 50 cfs.

Table 1 - Average Monthly Generation Estimates

Month	Generation (MWh)	Month	Generation (MWh)
January	12,384	July	5,897
February	9,161	August	1,584
March	10,401	September	2,463
April	12,467	October	7,380
May	14,679	November	11,757
June	12,607	December	10,943
	Average Annual Generation		**111,718**

1.3.2 Project Nexus to Economics

This section describes the nexus between Project operations and effects on the resource to be studied, and how the study results will inform the development of license requirements. In determining whether to issue a license for this project, the Commission considers a number of public interest factors, including project economics. The Commission must ensure that any license issued be best adapted to a comprehensive plan for improving or developing a waterway. Therefore, the Commission must have sufficient information on project costs and the hydropower potential of the site to evaluate the potential benefits of the project and develop any license requirements.

2 STUDY METHODS

In accordance with 18 CFR §5.11(d)(1) and §5.11(d)(5), this section provides a detailed description of the study methodology. The study will use a proprietary feasibility model (Model) developed to evaluate hydroelectric projects. The Model inputs include streamflow, instream flow requirements, ramping rate restrictions, facility parameters (gross head, equipment efficiencies, and capacity), construction cost estimates, and power market trends. Inputs related to construction and operation and maintenance costs are developed using staff experience building and operating hydroelectric projects of similar scope and scale. Model outputs include daily generation, daily flows to the Project reach, economic metrics, and the marginal cost of power required to finance the development cost.

At this stage in the FERC licensing process, a number of important facility parameters are best estimates and may not reflect the final Project configuration. For example, the final siting of the diversion and powerhouse will determine the Project's net head and generation. Information from stream gauges installed at the proposed intake site will be used to update and verify existing hydrographs and flow duration curves.

2.1 TURBINE SIZING AND PROJECT FLOWS

The Project's capacity will be determined by the available head and flow. As proposed, the Project has the potential to generate up to 25 MW of power instantaneously. The turbines are sized to maximize generation given an assumed Project configuration. To optimize the average annual generation the turbine capacities are iteratively changed until flows occurring with the greatest frequency coincide with the peak efficiency of the generating equipment.

Generation flows are estimated by calculating average daily flows and flow duration curves from the factored flows developed in the Hydrology Study Plan. Average daily flows are calculated using 1994 - 2012 calendar years. Flow duration curves are developed using the standard error method and applying it to the 1989 - 2011 water years. The flow duration curves plot exceedance probability versus magnitude of discharge. Exceedance probability is the probability that a given flow will be equaled or exceeded in a specified time interval. For the Project both annual and monthly flow duration curves are developed and presented in the Hydrology Study Report. They are included in Appendix A of this report for completeness.

2.2 DEVELOPMENT COST & ALTERNATIVE COST OF POWER

The capital cost of constructing the Project and purchasing principal equipment will be estimated using known costs for projects of similar scope and scale. Annual O&M costs of the Project facilities will be estimated by scaling O&M costs from facilities with similar configurations and personnel requirements. These estimates will incorporate an appropriate discount rate (time-value of money), depreciation, and annual fees and taxes.

The alternative cost of power in the Pacific Northwest Region is assumed to be the alternative cost of power that Puget Sound Energy would purchase on a competitive basis. Also, Bonneville Power Administration (BPA) has a tier 2 rate which is the cost of adding new generation to the area. Mid-C rates are not representative of the alternative cost of power in the region because Mid-C power is a surplus product which cannot be secured on a contractual basis. Tier 1 rates are only available to public or cooperative utilities while Tier 2 rates are available to public or cooperative utilities and requesting investor-owned utilities subject to the terms of the Northwest Power Act. Tier 2 rates are representative of wholesale energy rates available to balancing authorities which may have an interest in purchasing power from the Project. Tier 2 rates are not representative of the levelized cost of energy over the next 20 years and do not contain environmental attributes.

BCH estimates that the expected cost of power in 2019 the “west side” of the Pacific Northwest Region will be approximately $70.00 per MWh.

2.3 COST OF PM&E MEASURES

The estimated cost of lost generation for PM&E measures will be determined as they are proposed for: (1) minimum flow releases in the project reach for aquatic resources; (2) ramping rate restrictions; and (3) providing flows in the project reach for recreation. The

cost of lost generation due to these PM&E measures will be quantified by applying the PM&E measures to the Model and noting the change in average annual generation. The results of separate study reports, particularly those related to aquatic resources and recreation will provide the range of potential instream flow requirements.

3 RESULTS

The study results are based on the Project configuration as presented in Section 1.3 Project parameters may change as study information for related resources becomes available.

3.1 TURBINE SIZING AND PROJECT FLOWS

A range of turbine capacities were investigated. The turbine configuration resulting in the greatest average annual generation would utilize four equally sized Pelton wheel turbine and generator units. Configurations that were investigated are summarized in Table 4.

Table 2 - Turbine configuration, average annual generation, and plant factor.

Facility Capacity (cfs)	Average Annual Gen. (MWh)	Plant Factor
1,000 cfs	111,613	51.0 %
975 cfs	111,640	51.0 %
950 cfs	111,666	51.0 %
925 cfs	111,689	51.0 %
900 cfs	111,718	51.0 %
875 cfs	111,745	51.0 %
850 cfs	111,769	51.0 %
825 cfs	111,783	51.0 %
800 cfs	111,794	51.0 %
775 cfs	110,990	50.7 %
750 cfs	109,570	50.0 %
725 cfs	108,074	49.3 %
700 cfs	106,489	48.6 %
675 cfs	104,815	47.9 %
650 cfs	103,043	47.1 %
625 cfs	101,168	46.2 %
600 cfs	99,182	45.3 %

In Table 4 it may be observed that the greatest average annual generation is achieved with a facility capacity of 800 cfs. Marginal gains are made by increasing the capacity of the facility to the proposed 900 cfs.

Figure 2 provides a graphical view of 1994 - 2012 average discharge characteristics at the proposed intake location. The chart shows average daily flows, average flows diverted for generation, and average residual flows in the project reach over a 19 year period. The proposed turbine capacity of 900 cfs is shown as a solid red line while the mean annual flow of 596 cfs is shown as a solid black line. Because Figure 2 averages proposed operations the generation line doesn't reach the proposed turbine capacity

Figure 3 illustrates how the Project would be operated in a calendar year. The generation band is from 50 cfs to 950 cfs, however in practice the turbines can't run until 10 cfs can be diverted without drawing the river below the instream flow requirement. So in instances where the flows are less than the instream flow requirements plus 10 cfs the facility would not run, this can be seen in portions of August and September.

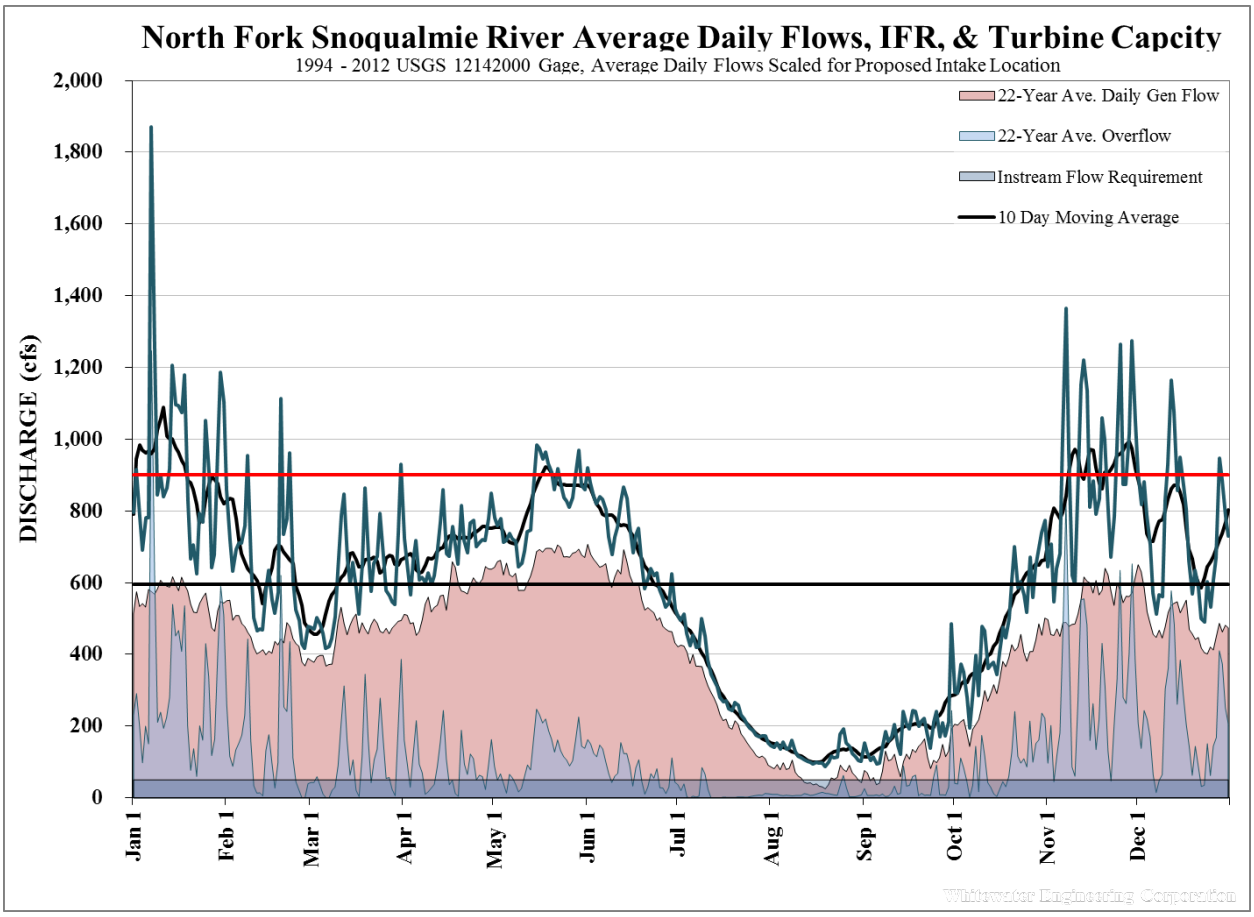


Figure 2 - Average daily flows, turbine capacity, and overflow of proposed intake location.

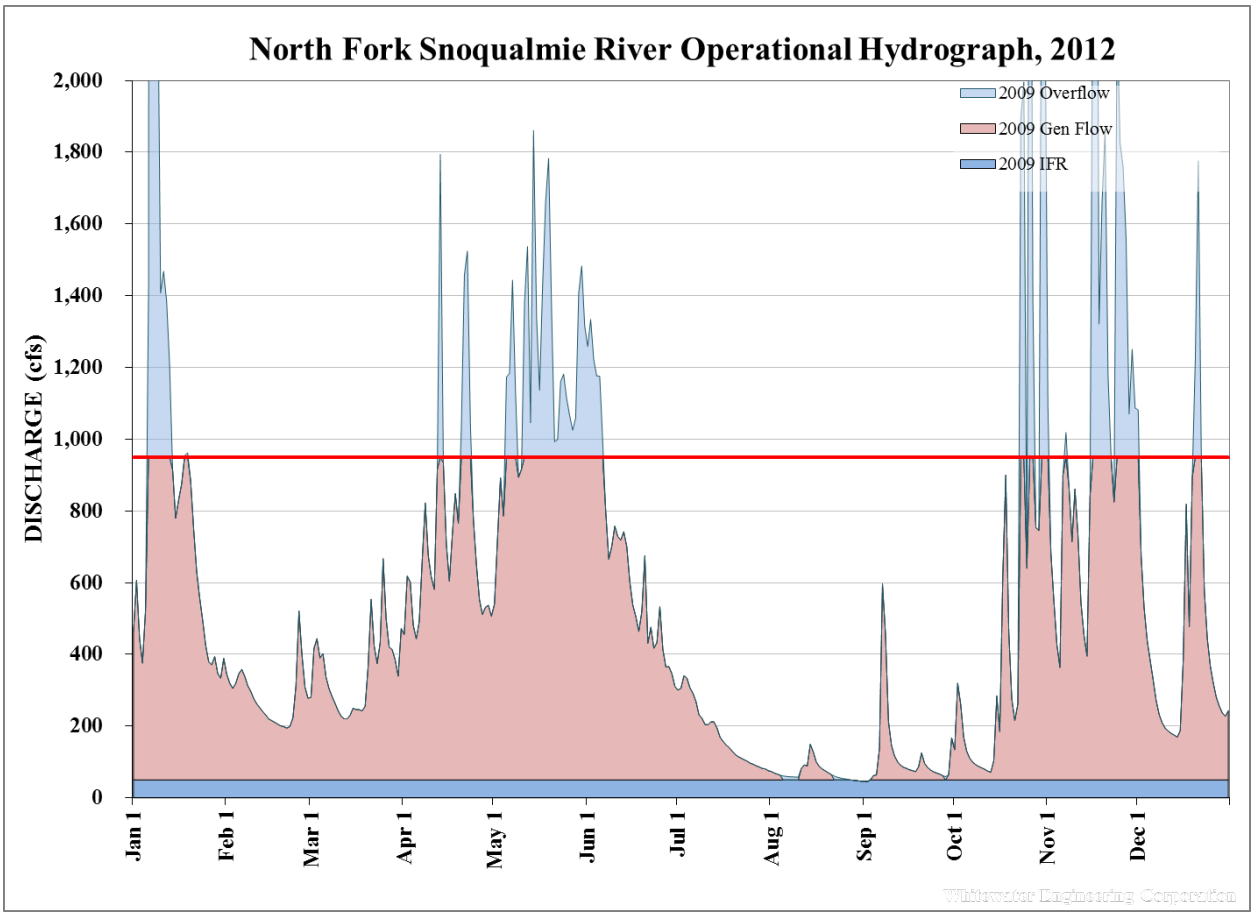


Figure 3 - Operational hydrograph for the 2012 calendar year.

3.2 DEVELOPMENT COST & ALTERNATIVE COST OF POWER

The estimated development cost for the Project is approximately $2,640 per installed kilowatt of capacity with an approximate total cost of $ 66 MM. This cost may fluctuate as design revisions incorporate stakeholder and resource agency input. The estimated annual O & M cost is approximately $951,000 per year. At this development starting cost the energy rate required to support the development of the project is $70/MWh. The energy rate would increase annually 2.5%. The estimated development cost is summarized in Table 5 and the estimated annual expenses are summarized in Table 6.

Table 3 - Estimated development cost for the Black Canyon Hydroelectric facility.

Item	Estimated Cost
Licensing and Design	$ 6,160,000
Land & Land Rights	$ 1,100,000
Intake	$ 5,335,000
Penstock & Tunnel	$27,600,000
Powerhouse	$ 4,840,000
Turbine and Generator Set	$ 5,200,000
Switchgear	$ 2,150,000
Transformer & Substation	$ 3,000,000
Transmission	$ 1,715,000
Mobilization	$ 3,435,000
Contingency	$ 5,620,000
Total	**$ 66,155,000**

Table 4 - Estimated O & M costs for the Black Canyon Hydroelectric facility.

Annual Expense	**Cost**
Operations & Maintenance	
Turbine Maintenance	$ 30,000
Transmission Maintenance	$ 12,000
Labor	$ 120,000
Site Maintenance & Improvements	$ 12,000
Fuel & Equipment	$ 30,000
Rolling Stock	$ 6,000
Utilities	$ 8,000
SubTotal	**$ 218,000**
Administrative Costs	
Property taxes	$ 448,000
Insurance	$ 189,000
General Administrative	$ 46,000
Contingencies	$ 50,000
SubTotal	**$ 733,000**
Total	**$ 951,000**

3.3 COST OF PM&E MEASURES

The cost of lost generation due to PM&E measures are provided where a PM&E measure is proposed or a likely range of values can be estimated. The cost of lost generation for each PM&E measure is based on the $80/MWh rate needed to develop the Project.

3.3.1 Instream Flow Requirements

Lost generation due to instream flow requirements is summarized in Table 7. The minimum recorded flow of 35 cfs is used to estimate baseline generation. Subsequent flows listed in Table 7 are representative of possible instream flow values for the Project Reach. Instream flow requirements will be developed as a result of agency consultation and comments on relevant resource study reports including Environmental Flows, Aquatic Resources, and Geomorphology.

Table 5 - Lost generation associated with instream flow requirements as a PM&E measure.

IFR (cfs)	Average Annual Generation (MWhr)	Average Annual Lost Generation (MWhr)	Average Annual Lost Revenue
35	115,024	-	-
50	111,718	3,306	$ 264,480
75	106,474	8,550	$ 684,000
100	101,495	13,529	$ 1,082,320

3.3.2 Ramping Rate Restrictions

Ramping rate restrictions for the Project will be the result of agency consultation and review of relevant resource reports. At this time no recommendations have been made and therefore the cost of lost generation due to ramping rates has not been investigated.

3.3.3 Recreational Flows

The cost of lost generation to provide recreational flows in the Project Reach will be affected by ramping rate restrictions that may be prescribed as a PM&E measure. The true cost of lost generation to provide recreational flows will include any time required to provide recreation flows and then return to normal generation without exceeding ramping rate restrictions. A brief analysis conducted to assess the partial cost of lost generation to provide recreational flows assumes that there are no ramping rate restrictions, Table 8.

Table 6 - Lost generation associated with recreational flows as a PM&E measure.

Recreation Flows (cfs)	Frequency (days/week)	Avg. Annual Gen. (MWhr)	Avg. Annual Lost Gen. (MWhr)	Avg. Annual Lost Revenue
350 - 500	2 - sat/sun	107,640	4,078	$ 326,240
500 - 700	2 - sat/sun	107,574	4,145	$ 331,600
700 - 1,100	2 - sat/sun	108,050	3,669	$ 293,520
350 - 1,100	2 - sat/sun	103,626	8,092	$ 647,360

4 CONCLUSIONS

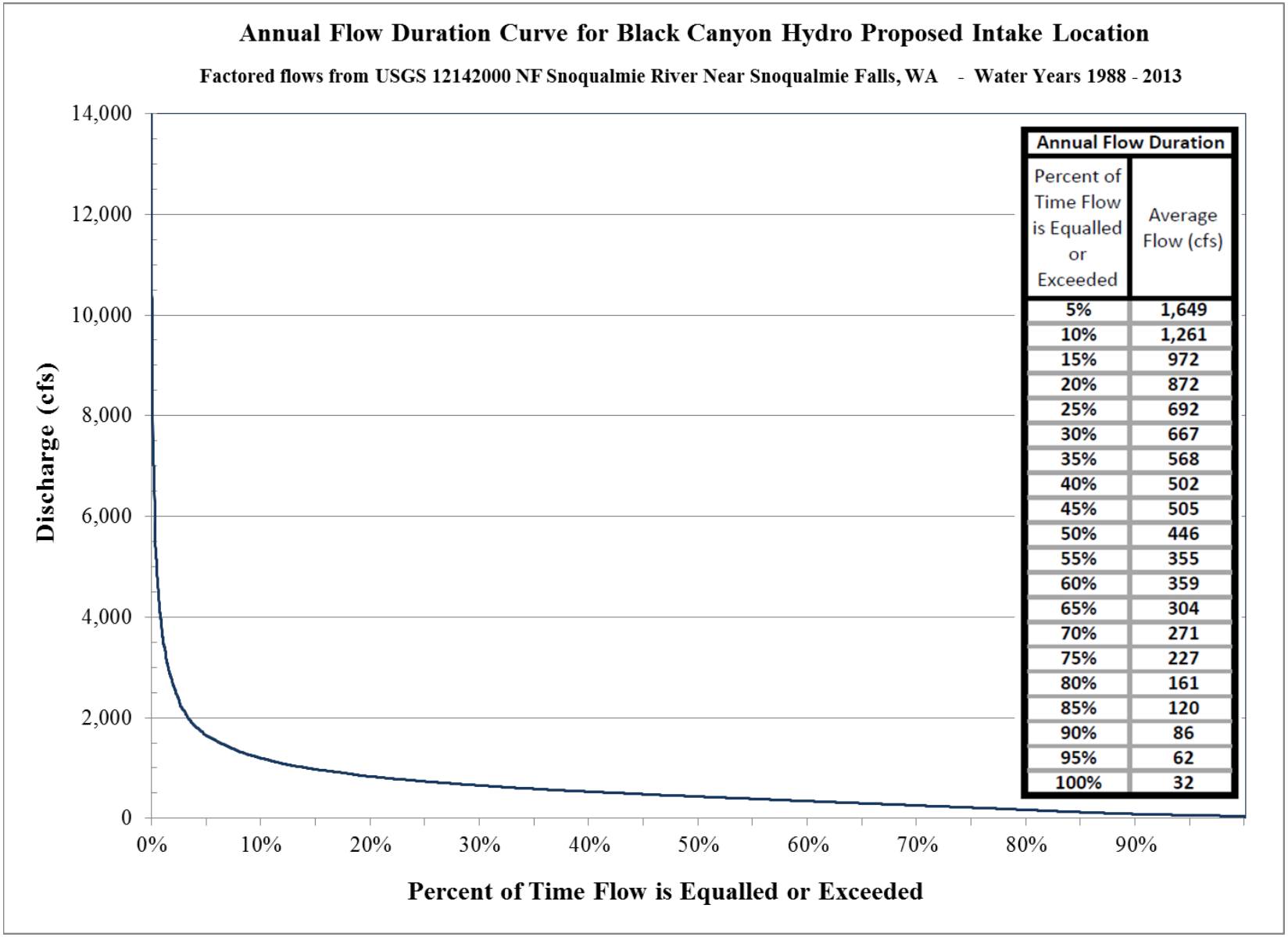
In conclusion to the Hydropower Potential & Project Economics Study Report a summary of key findings are presented.

- The estimated design flow of 900 cfs may not achieve the greatest average annual generation. Preliminary results indicate a facility capacity of 800 cfs will maximize the generation potential of the plant. A review of the possible cost savings associated with downsizing the facility will be investigated prior to moving forward with the design and license application.
- The estimated development cost for the facility is approximately $2,640 per MW of installed capacity or $66 MM which would require a starting energy rate of $70/MWh, increasing 2.5% per year.
- The estimated annual operations and maintenance cost for the facility is approximately $951,000/year.
- The estimated cost of instream flow requirements as a PM&E measure range from $264,480 to $1,082,320 with an instream flow requirement of 50 and 100 cfs respectively.
- The estimated cost of ramping rate restrictions as a PM&E measure cannot be estimated at this time as no ramping rate restrictions have been proposed for the Project. Agency consultation and review of relevant resource studies will likely determine any proposed PM&E measures and will be investigated at that time.
- The estimated cost of recreational flows as a PM&E measure will be directly impacted by any ramping rate restrictions imposed on the Project. A preliminary estimate which assumes no ramping rate restrictions are imposed ranges from $326,240 to $647,360 with recreational flow rages between 350-500 and 350-1,100 respectively.

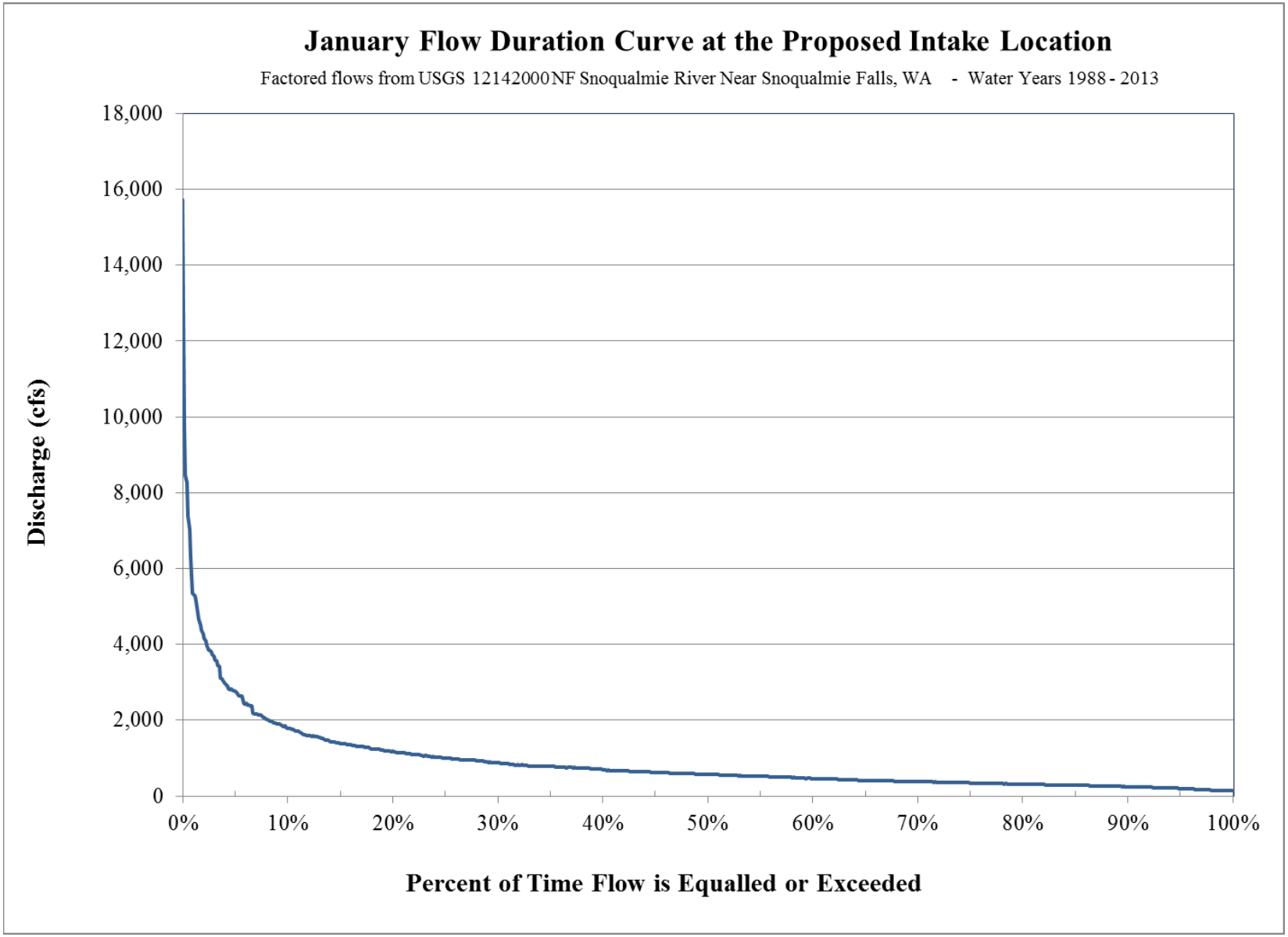
5 REFERENCES

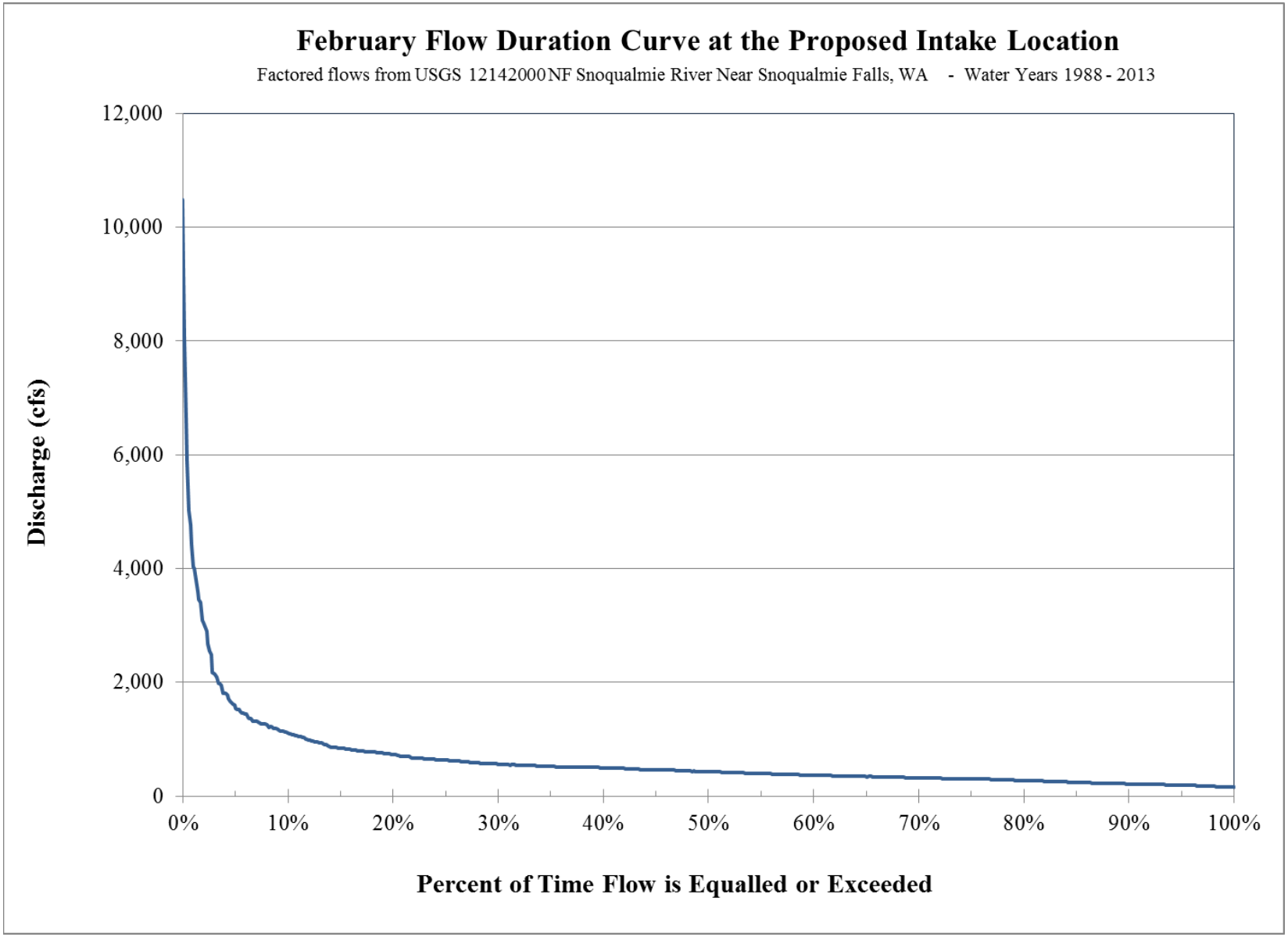
2012, BCH, LLC, Hydropower Potential and Project Economics Study Plan, Bellingham, WA

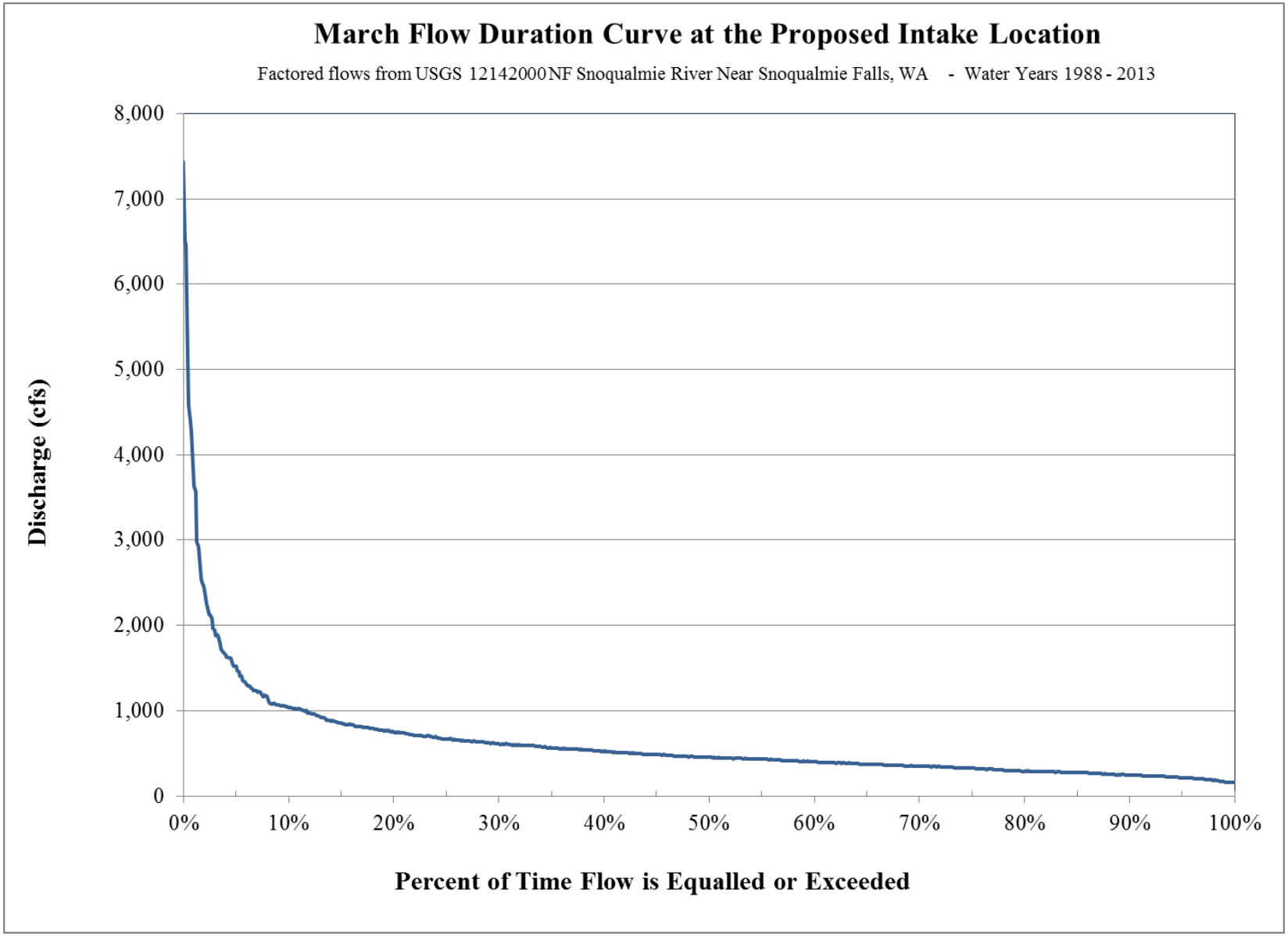
APPENDIX A - ANNUAL & MONTHLY FLOW DURATION CURVES

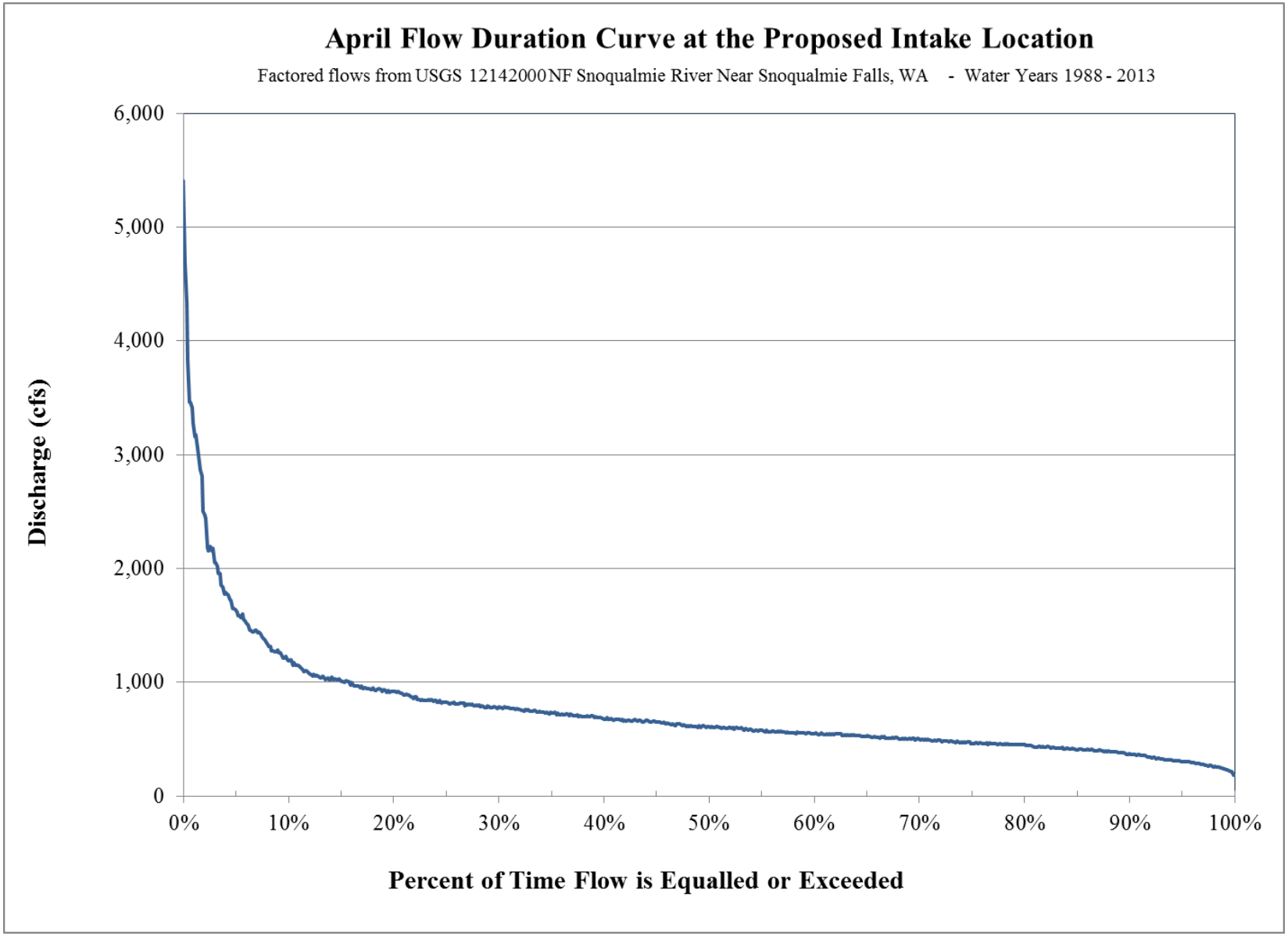


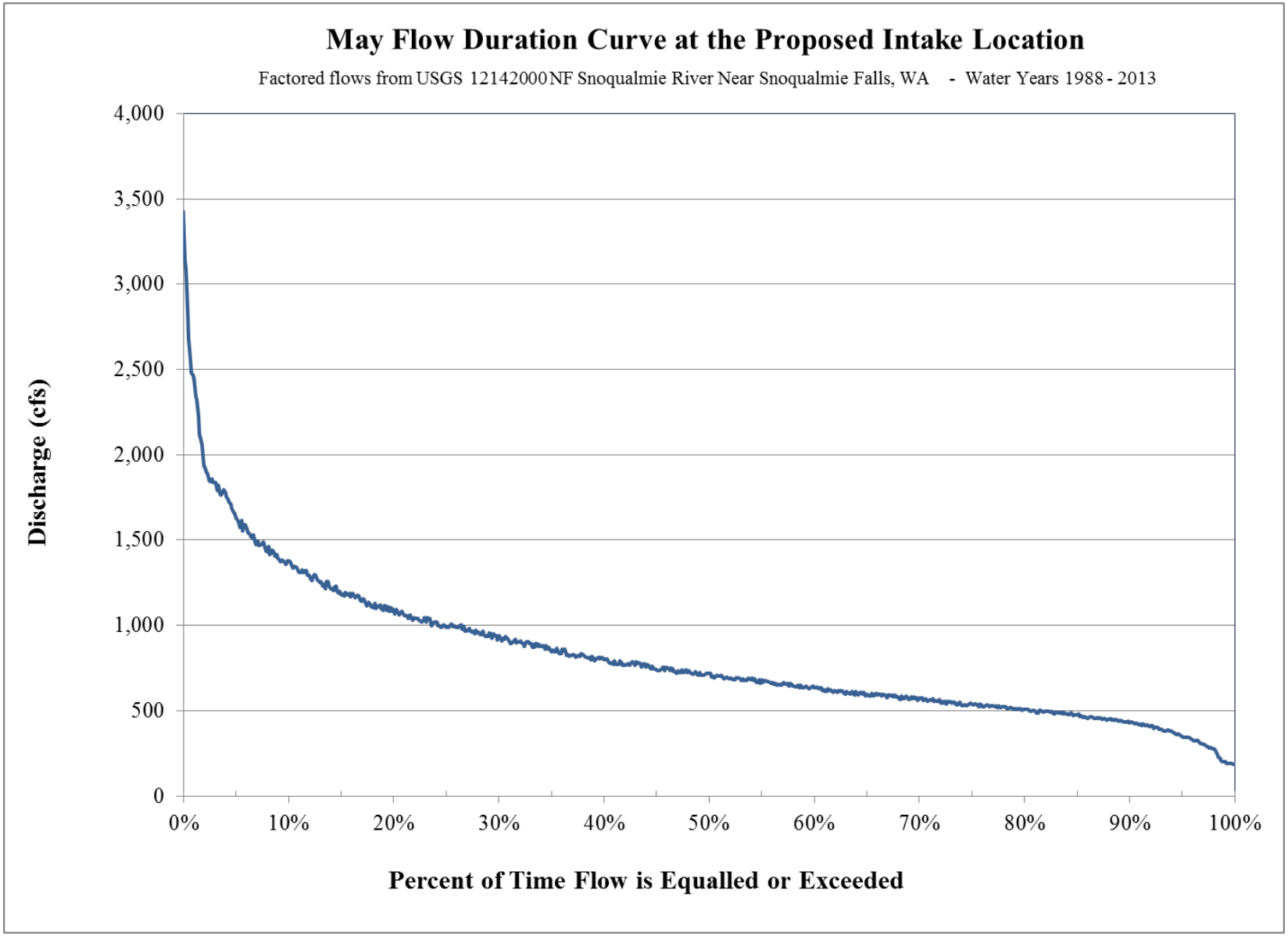
Annual Flow Duration	
Percent of Time Flow is Equalled or Exceeded	Average Flow (cfs)
5%	1,649
10%	1,261
15%	972
20%	872
25%	692
30%	667
35%	568
40%	502
45%	505
50%	446
55%	355
60%	359
65%	304
70%	271
75%	227
80%	161
85%	120
90%	86
95%	62
100%	32

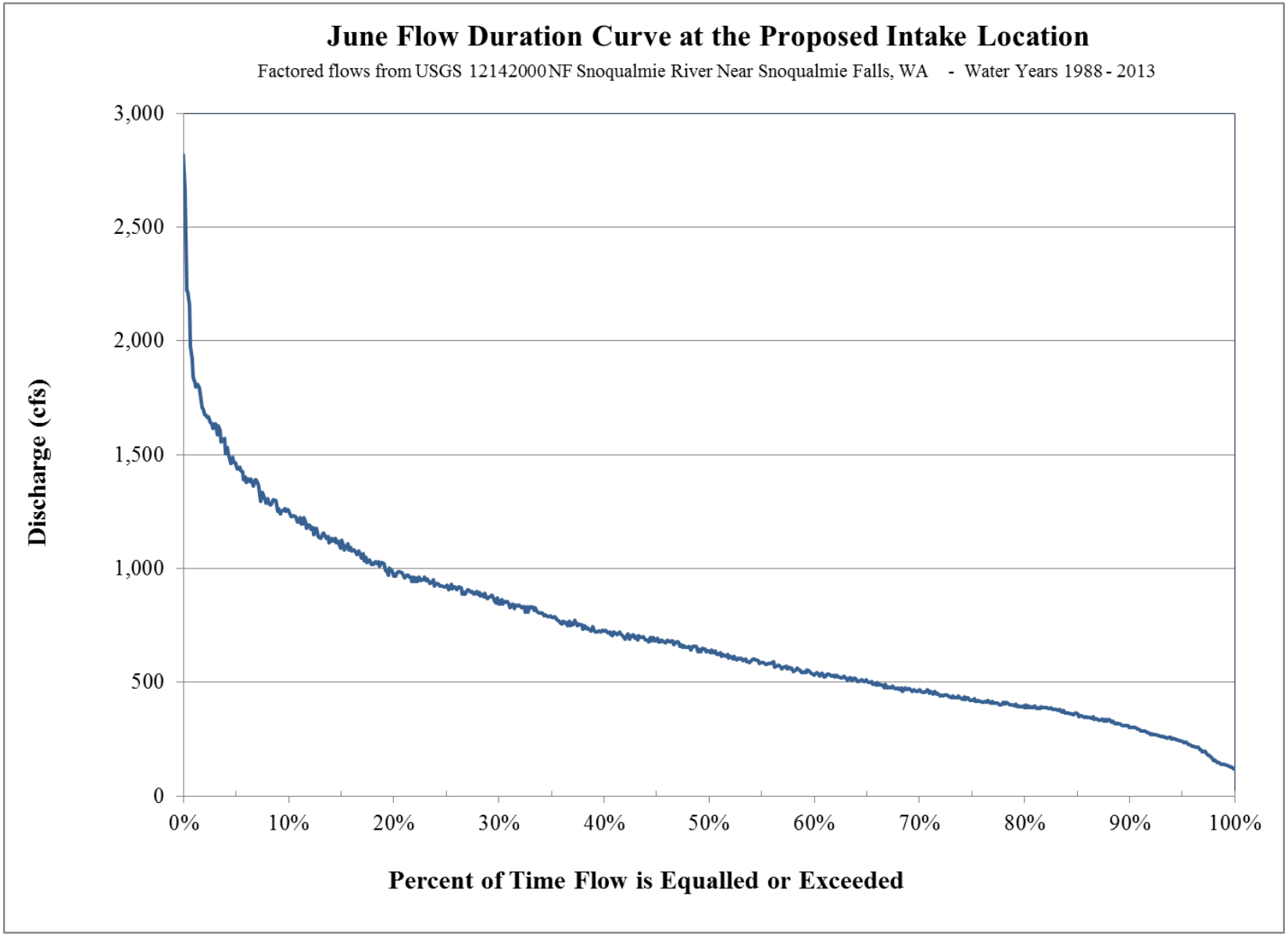

January Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded

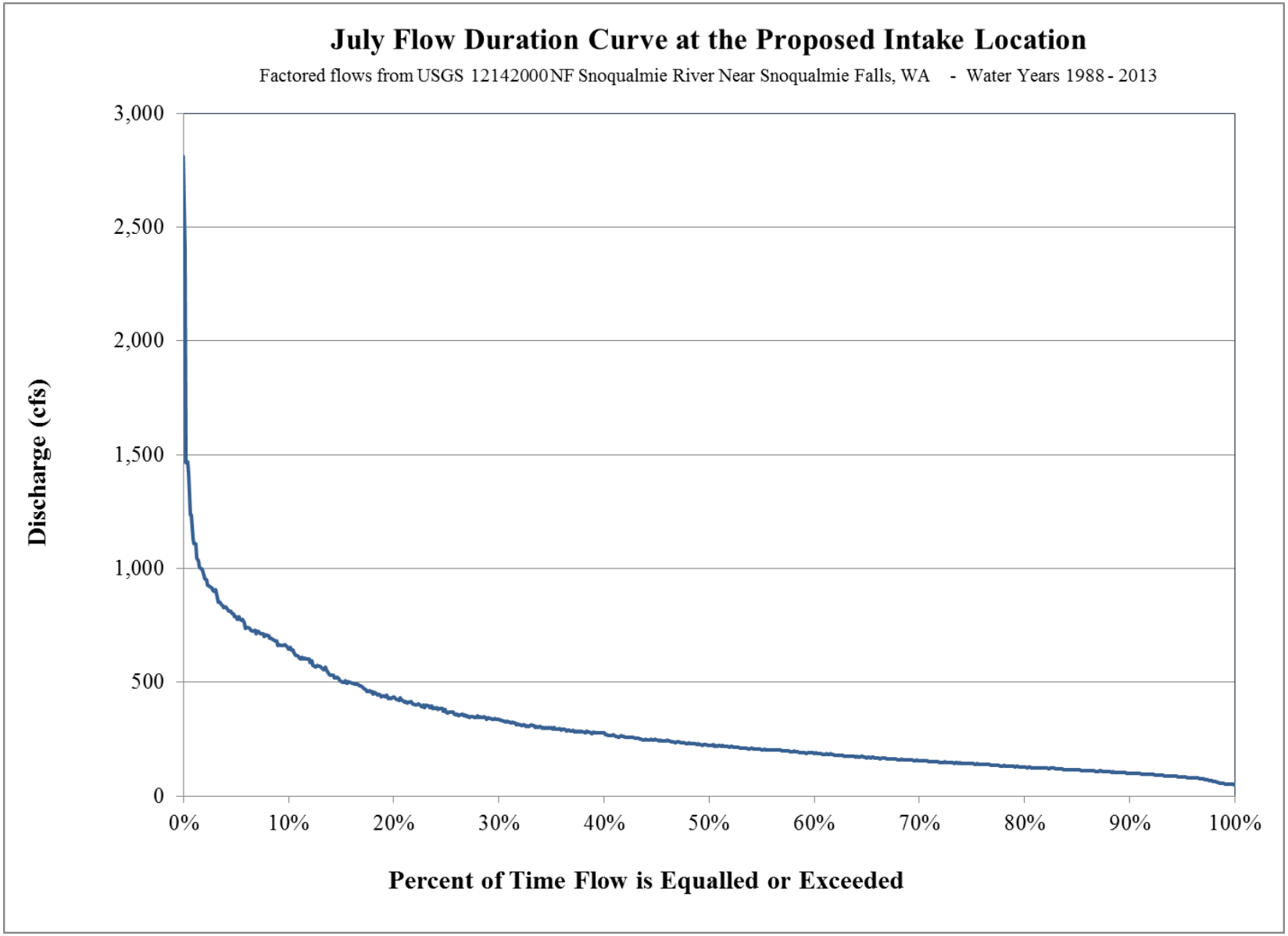

February Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
12,000
10,000
8,000
6,000
4,000
2,000
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded

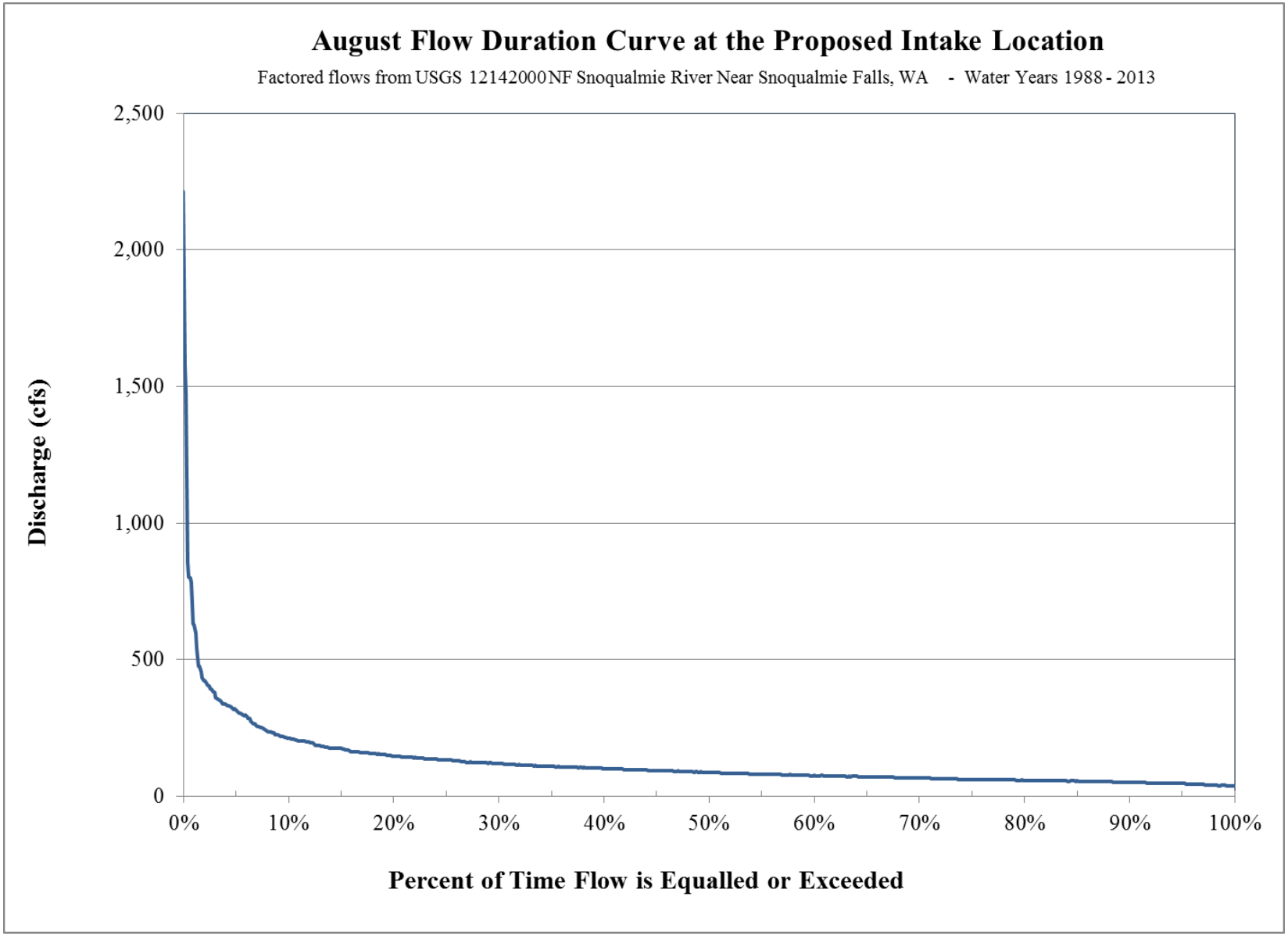

March Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded

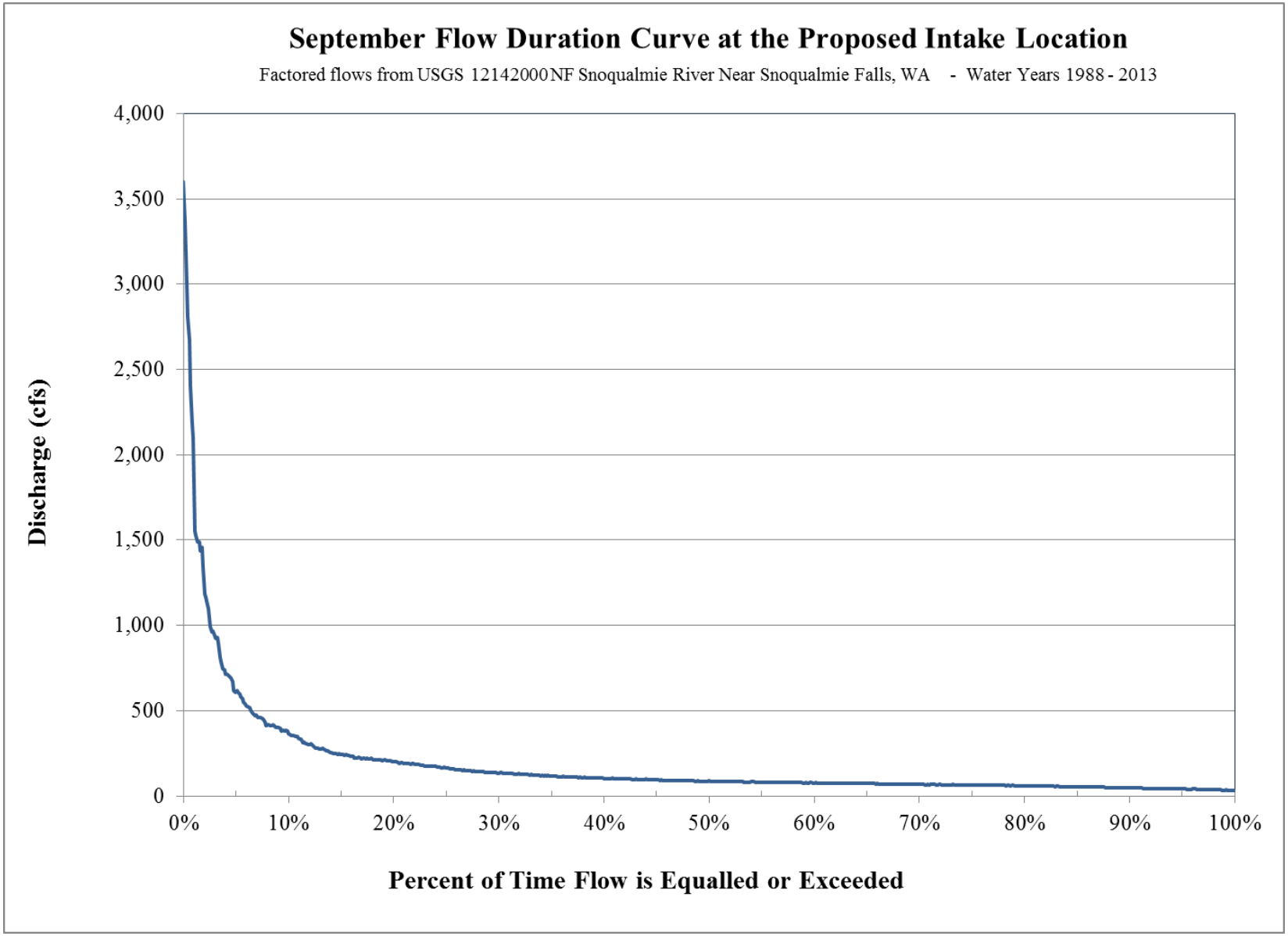

April Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
6,000
5,000
4,000
3,000
2,000
1,000
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded

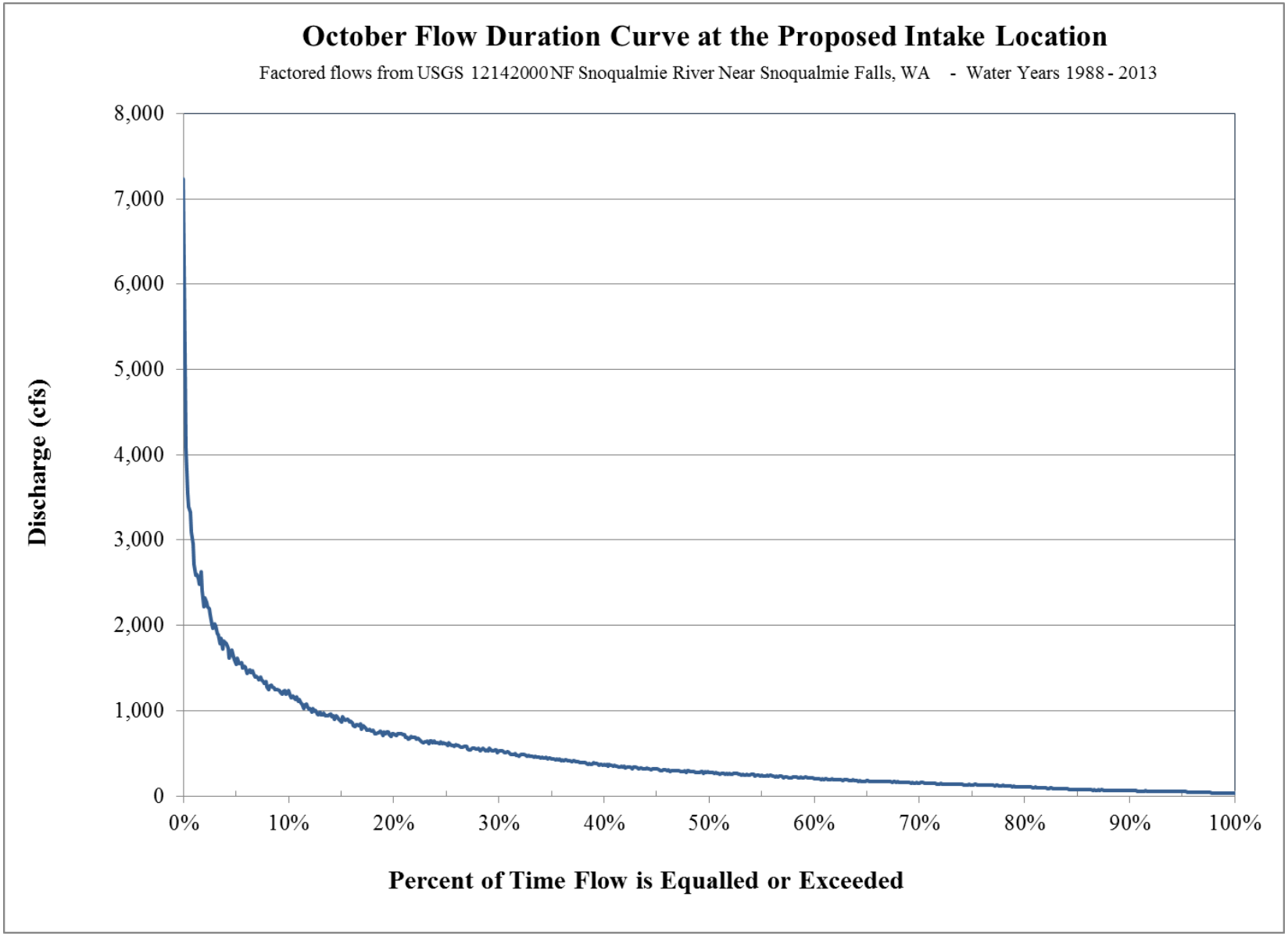

May Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded

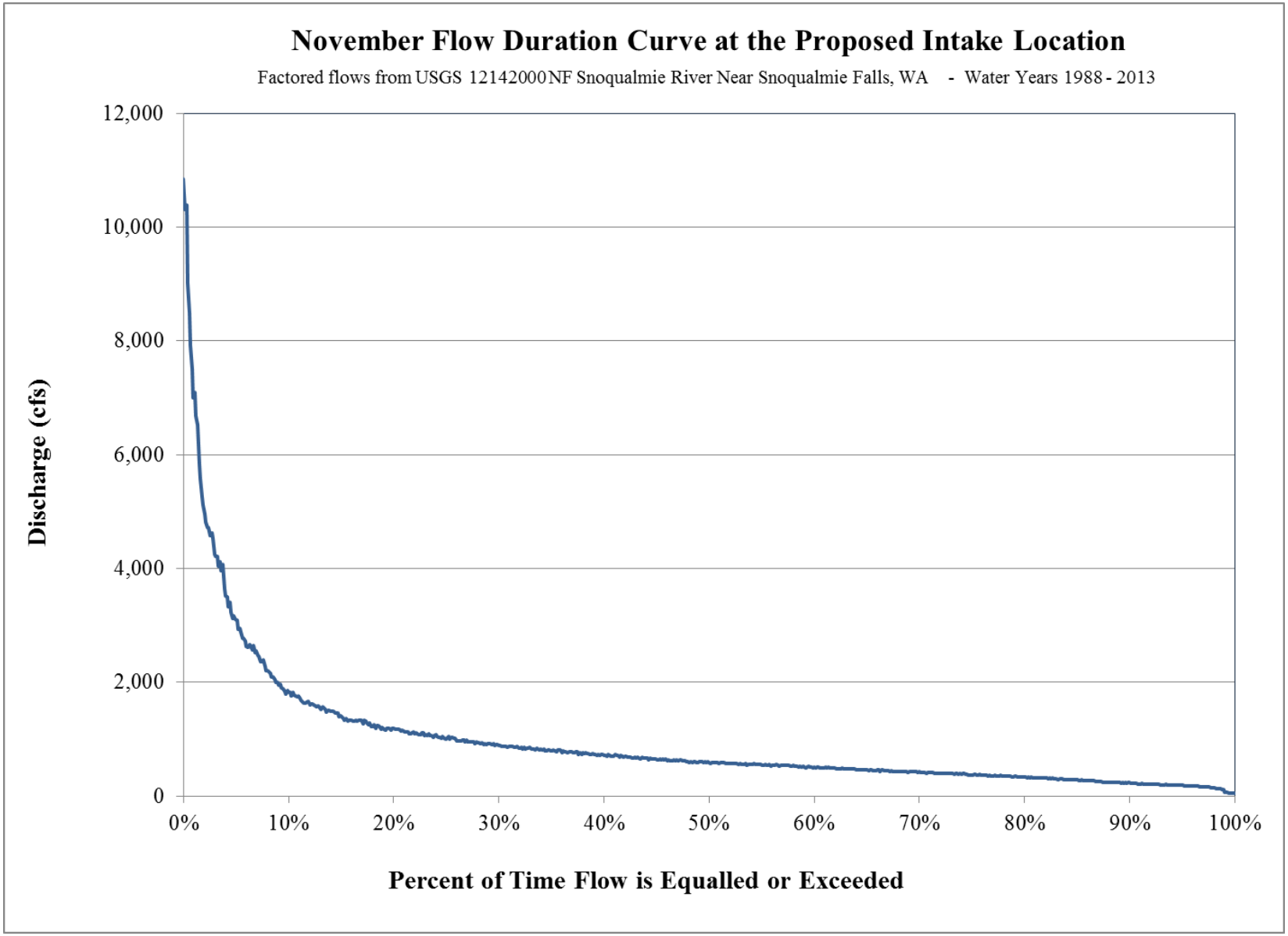

June Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
3,000
2,500
2,000
1,500
1,000
500
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded

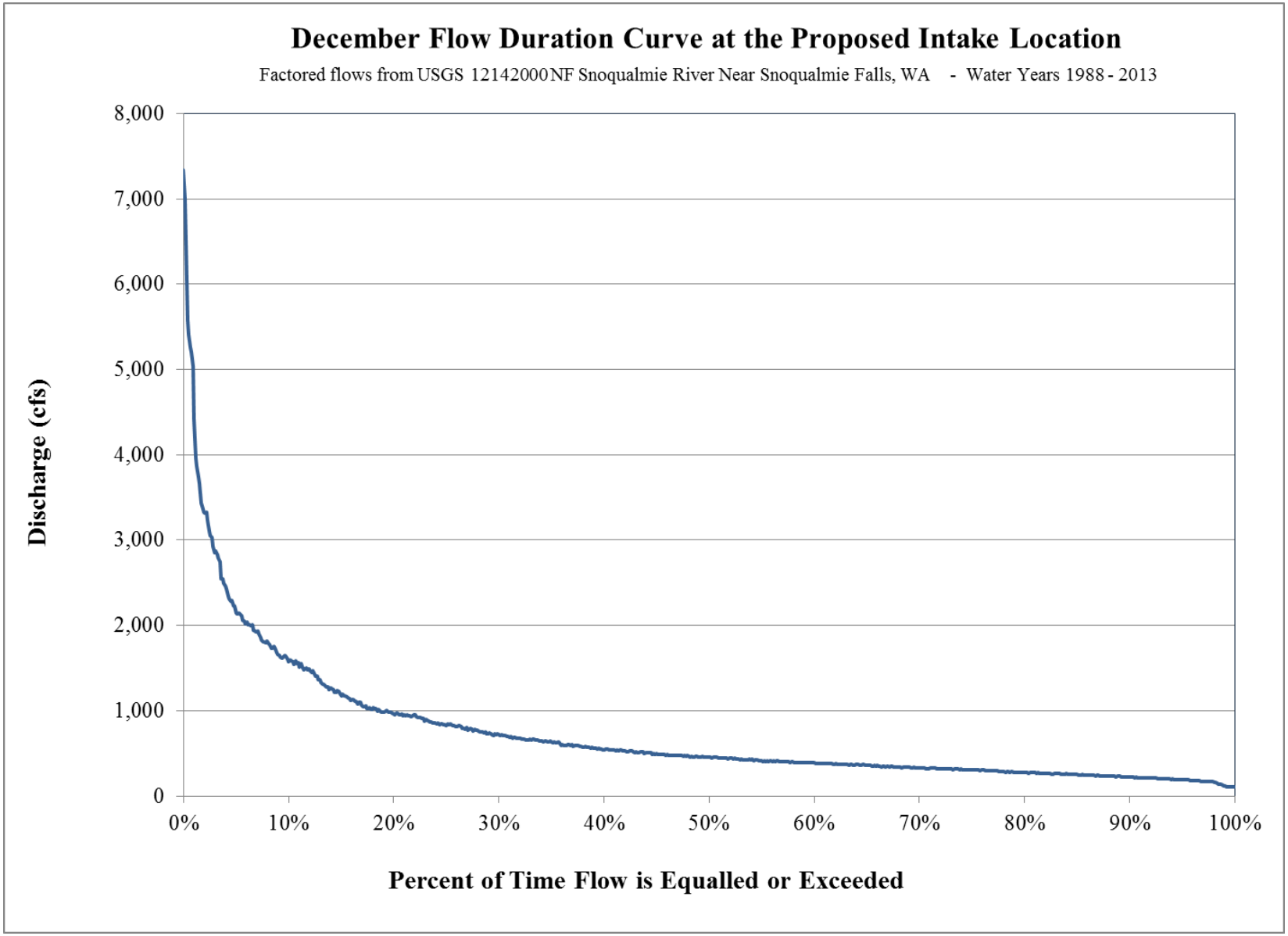

July Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
3,000
2,500
2,000
1,500
1,000
500
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded


August Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
2,500
2,000
1,500
1,000
500
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded


September Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded


October Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded


November Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
12,000
10,000
8,000
6,000
4,000
2,000
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded


December Flow Duration Curve at the Proposed Intake Location
Factored flows from USGS 12142000 NF Snoqualmie River Near Snoqualmie Falls, WA - Water Years 1988 - 2013
Discharge (cfs)
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percent of Time Flow is Equalled or Exceeded