Similkameen River International Steering Committee

Similkameen Watershed Study

H327097
Rev. 2
February 2009
Similkameen River International Steering Committee

Similkameen Watershed Study


Reviewed by: Donald G. Murray, P. Eng.

Feb 5, 2009

Date

Feb 5, 2009

Date
Disclaimer

This report has been prepared by Hatch Ltd. for the sole and exclusive use of Similkameen Valley Planning Society (the “Client”) and for the Similkameen Watershed Interim Steering Committee (“ISC”) for the purpose of assisting the management of the Client in making decisions with respect to the potential development of the Similkameen Watershed Study; and shall not be (a) used for any other purpose, or (b) provided to, relied upon or used by any third party.

This report contains opinions, conclusions and recommendations made by Hatch Ltd., using its professional judgment and reasonable care. Use of or reliance upon this report by Client is subject to the following conditions:

(a) the report being read in the context of and subject to the terms of the Agreement between Hatch Ltd. and the Client dated January 9, 2008 (the “Agreement”), including any methodologies, procedures, techniques, assumptions and other relevant terms or conditions that were specified or agreed therein;

(b) the report being read as a whole, with sections or parts hereof read or relied upon in context;

(c) the conditions of the site may change over time due to natural forces or human intervention, and Hatch Ltd. takes no responsibility for the impact that such changes may have on the accuracy or validity or the observations, conclusions and recommendations set out in this report; and

(d) the report is based on information made available to Hatch Ltd. by the Client or by certain third parties; and unless stated otherwise in the Agreement, Hatch Ltd. has not verified the accuracy, completeness or validity of such information, makes no representation regarding its accuracy and hereby disclaims any liability in connection therewith.
# Table of Contents

Executive Summary .................................................................................................................... 1

1. Introduction .......................................................................................................................... 3
   1.1 Authorization and Work Scope ...................................................................................... 3
   1.2 Background to Present Study ....................................................................................... 4
   1.2.1 Similkameen River Hydroelectric Project .................................................................. 4
   1.2.1.1 International Joint Commission Study ................................................................. 4
   1.2.1.2 Similkameen Basin Storage Study (1961) ............................................................. 6
   1.2.1.3 Princeton Power & Light (PP&L) Hydroelectric Investigations ......................... 7
   1.2.1.4 Hatch Energy Update of PP&L Study ................................................................. 8

2. Watershed Site Conditions .................................................................................................... 9
   2.1 General .......................................................................................................................... 9
   2.2 Water Data .................................................................................................................. 11
      2.2.1 Stream Gauging Data ......................................................................................... 11
      2.2.2 Precipitation and Temperature .......................................................................... 11
      2.2.3 Water Quality ..................................................................................................... 12
   2.3 Water Supply ............................................................................................................... 12
   2.4 Water Demand ............................................................................................................ 13
      2.4.1 General ............................................................................................................... 13
      2.4.2 Water Licenses .................................................................................................... 14
      2.4.3 Land Use ............................................................................................................ 14
      2.4.4 Agricultural ........................................................................................................ 15
      2.4.5 Mining ................................................................................................................ 15
      2.4.6 Industrial ............................................................................................................ 16
   2.5 Flood Control ............................................................................................................... 16
   2.6 Water Storage Needs .................................................................................................... 16

3. Potential Storage Sites for Development ........................................................................... 18
   3.1 Shanker’s Bend Site ..................................................................................................... 18
   3.2 Enloe Hydro Project Site ............................................................................................. 18
   3.3 Assessment of Dam Sites within Canada .................................................................... 18
   3.4 Upper Similkameen Storage Sites ............................................................................... 20
      3.4.1 Summary of Initial Stewart-EBA Pre-Feasibility Study ........................................... 20
      3.4.2 Review of EBA Feasibility Study Dam Site ......................................................... 20
         3.4.2.1 Update of Cost Estimates for Pumphouse Dam Site ........................................ 21
         3.4.2.2 Energy Estimates ......................................................................................... 28
         3.4.2.3 Reservoir Storage ....................................................................................... 29
         3.4.2.4 Economic Analysis ...................................................................................... 32
         3.4.2.5 Potential Revenue Sources ....................................................................... 35
         3.4.2.6 Increased Storage ....................................................................................... 38
         3.4.2.7 Summary .................................................................................................... 39

4. Conclusions and Recommendations .................................................................................... 40
   4.1 Conclusions .................................................................................................................. 40
   4.2 Recommendations ....................................................................................................... 41

5. References .......................................................................................................................... 43
Appendices

Appendix A  Listing of Water Licenses

List of Tables

Table 1  Summary of IJC Study Storage Site Data ................................................................. 5
Table 2  Summary of Irrigable Acreage and Water Requirements (For Sprinkler Irrigation) ........... 6
Table 3  Similkameen Basin Potential Water Demand .............................................................. 7
Table 4  Summary of Upper Similkameen River Dam Sites for Hydroelectric Development .......... 8
Table 5  Monthly and Annual Mean Discharges and Extremes of Discharge for the Period of Record of Selected Stations along the Similkameen River ........................................ 10
Table 6  Potential Similkameen Basin Flow Deficiency in Critical Hydrologic Water Year .......... 13
Table 7  Summary of Water Licenses ...................................................................................... 14
Table 8  Principal Statistics of Stewart-EBA Pre-Feasibility Development Options...................... 21
Table 9  EBA Cost Estimate Summary of Pumphouse Site Hydro Alternatives (1994 Price Level) .... 21
Table 10 Engineering Cost Assumptions ................................................................................. 26
Table 11 Revised Cost Estimate Summary of Pumphouse Hydro Alternatives (2008 Price Level) .... 27
Table 12 Summary of Available Energy Estimates (GWh) ...................................................... 28
Table 13 Rule Curve – End of Month Elevation (m) .................................................................. 29
Table 14 Comparison of Streamflow at the Princeton Gauge with and without Flow Regulation from 600 ft (183 m) High Dam................................................................. 33
Table 15 Basic Assumptions for Economic Analyses ................................................................. 34
Table 16 Summary of Total Capital Requirements of Pumphouse Hydro Alternatives (2008 Price Level) ................................................................. 34
Table 17 Estimated Annual Cost of Power for Pumphouse Hydro Alternatives (2008 Price Level) ... 35

List of Figures

Figure 1  Key Map
Figure 2  Potential Sorage Sites
Figure 3  Hydrometeorological Network
Figure 4  Location of WSC Gauging and Climate Data Stations
Figure 5  Similkameen River at Princeton - Hydrographs
Figure 6  Similkameen River near Headley – Hydrographs
Figure 7  Similkameen River near Nighthawk – Hydrographs
Figure 8  Tulameen River at Princeton – Hydrographs
Figure 9  Princeton Airport – Precipitation
Figure 10 Princeton Airport – Temperature
Figure 11 Osoyoos West – Precipitation
Figure 12 Osoyoos West – Temperature
Figure 13  Cumulative Water License Discharges
Figure 14  Electoral Area, Communities and Indian Reserves
Figure 15  Agricultural Land Reserves, Parks and Ski Areas
Figure 16  Recorded Daily Hydrographs for 1972 Spring Flood
Figure 17  Regulated Daily Hydrographs for 1972 Spring Flood
Figure 18  Location Map of Similkameen Storage Dam Site
Figure 19  Similkameen Hydro Project – General Arrangement
Executive Summary

The primary purpose of the Similkameen Watershed Study is to identify the sites that appear to provide the greatest promise of development with respect to water supply, flood control, water quality and hydroelectric development. The study was also to perform a review of past studies and data that summarized the need for such a storage reservoir.

From our initial review of the storage sites previously investigated, the most promising sites that were previously identified and investigated in some detail were those located in the narrow Similkameen River canyon upstream of the town of Princeton. Of the three sites considered by PL&P, the one located furthest downstream held the most promise for development, principally due to its hydroelectric potential, but also due to its location sufficiently upstream in the watershed as to provide for meaningful benefits for water supply, flood control and improved water quality during the summer months.

The most promising project would be comprised of either a roller-compacted-concrete dam or a rockfill embankment dam at a site identified as the Pumphouse location, which evidently was the Pumphouse location for water extraction to the Copper Mountain Mining site operation. A preliminary optimization study of dam height indicated that the dam should be 600 feet high or even possibly higher. The addition of a 3,000-foot long headrace tunnel would add to the hydroelectric potential and appear to reduce the cost of energy. The installed capacity of a hydroelectric installation would be 66 MW and possibly higher resulting in the cost of energy of 10.1 cents per kWh, assuming 30-year bond financing at 6% interest rate. As the project would provide headwater benefits to the proposed 9 MW Enloe Hydroelectric Project and to nine Columbia River Projects, it may be possible to establish cost sharing of the dam development with these other US owners of other hydroelectric installations that would further reduce the cost of a Similkameen Project development, possibly to less than 8.5 cents per kWh. Establishing carbon credit revenue may further reduce the cost of project development; however, some carbon footprint will occur from reservoir development.

Not included in the cost estimate is inclusion of an afterbay dam for flow re-regulation from a hydro plant’s daily peaking operation.

Water quality improvements could be substantial. While water quality data is not specifically known due to lack of data, the minimum water flow rates during the months of August through October could increase from a minimum of 2.5 m3/sec to 7.5 m3/sec, which certainly would improve the local fisheries habitat.

Water supply improvement would probably become more of a US side of the border benefit, although it could improve the potential of agricultural growth on the Canadian lands within the Similkameen watershed. We have not yet received any information on water demand from the US Army Corps of Engineers based on their current investigation of the Shanker’s Bend Project, which is a multipurpose project similar to the Similkameen Project. Some revenue for sale of water for agricultural use should be possible, and this would need to be investigated further with both US and Canadian water users. However, a previous study (Griffing May 1992) indicates that water sales may not be guaranteed due to prior rights held by the Washington Department of Fisheries and Indian Tribes. At any rate this issue would need to be further investigated to establish what baseline condition would need to prevail before additional water could be sold to downstream water users.
The Similkameen Project with a 600-foot high dam at the Pumphouse location would provide some nominal flood control benefits that would reduce the amount of damage to flood control levees and to property when levees are breached. Although the amount of flood damage has not been quantified from past flooding events, the dam should reduce flood damage through flow regulation that reduces the peak flow from the flood hydrograph. For example, the spring 1972 flood of record (a 200-year flood frequency event), with a peak discharge of 929 m3/sec at Hedley, would likely have been reduced by about 121 m3/sec.

It should be noted that during the winter months, frazil ice has created obstructions at bridge crossings, which have caused breaching of levees and subsequent flooding of property. A previous study noted that a reservoir project could actually aggravate such damage occurrences. We have not yet analyzed such an operation scenario to assess what operational changes could mitigate or reduce the occurrences of flood damages from frazil ice formation.
1. Introduction

1.1 Authorization and Work Scope

This Study was authorized by the Similkameen Valley Planning Society (Society) for the purpose of assessing the benefits of a storage dam development for flood control, water supply, ecological flow improvements and hydroelectric power development in the Similkameen River Watershed. Funds for this study were provided by the Similkameen Watershed Interim Steering Committee (ISC), which has the mandate to collate existing information on the hydrology of the Similkameen River and its tributaries and in gathering information in a preliminary step looking at the feasibility of dams and reservoirs on both sides of the Canada-U.S. border. The ISC is comprised of representatives from the Similkameen Valley in B.C. and Okanogan County in Washington State.

This report contains opinions, conclusions and recommendations made by Hatch Energy, using its professional judgment and reasonable care. Use of or reliance upon this report by Society and ISC is subject to the following conditions:

(a) the report being read in the context of and subject to the terms of the General Services Agreement between Hatch Energy and the Society dated January 9, 2008 (the “Agreement”), including any methodologies, procedures, techniques, assumptions and other relevant terms or conditions that were specified or agreed therein;

(b) the report being read as a whole, with sections or parts thereof read or relied upon in context;

(c) the conditions of a potential water development project (Project) may change over time or may have already changed due to natural forces or human intervention, and Hatch Energy takes no responsibility for the impact that such changes may have on the accuracy or validity or the observations, conclusions and recommendations set out in this report; and

(d) the report is based on information made available to Hatch Energy by the Society, ISC or by certain third parties and unless stated otherwise in the Agreement, Hatch Energy has not verified the accuracy, completeness or validity of such information, makes no representation regarding its accuracy and hereby disclaims any liability in connection therewith.

The intent of this initial study is to accomplish the following:

- Provide better definition to the benefits of water supply, flood control, ecological resource improvement and hydro power within the Similkameen watershed and the Okanagan Valley below the confluence of the two rivers that a Similkameen/Tulameen storage dam can provide; and

- Identify potential projects from the more promising sites based on a site survey assessment, which includes a survey of previous investigations of specific sites and from a survey of topographic mapping of the watersheds.

The study is to identify the sites that appear to provide the greatest promise of development based on a qualitative review. Then, once the Steering Committee receives more in-depth input from various
stakeholders, specific projects can be evaluated in detail through pre-feasibility investigations; then later through advanced feasibility investigation if a particular project is to be developed.

A map of the Similkameen River Basin is shown in Figure 1, which also shows the Okanagan River segment to its confluence with the Columbia River.

It should be noted that a parallel study to the one Hatch is performing for the upper Similkameen Basin is being performed by the Seattle District Army Corps of Engineers (COE) for Okanagan PUD, with the purpose of quantifying the water supply potential available for storage at a reservoir storage site at Shanker's Bend, located above Enloe Dam on the Similkameen River on the U.S. side of the international boundary. Because the Hatch study is scheduled for completion prior to the COE study, the COE may be able to perform sensitivity modeling with a storage project identified in the Hatch study for possible development evaluation.

The COE study will review available data from which to: 1) derive characteristics of the Similkameen River Basin, including quantification of Basin runoff; 2) assess current water demand; 3) identify storage needs, including water shortfalls, flood control needs, ecological flow improvement needs and water quality improvement needs; and 4) compare three different size reservoirs at the Shanker’s Bend dam site.

1.2 Background to Present Study

1.2.1 Similkameen River Hydroelectric Project

1.2.1.1 International Joint Commission Study

A 1955 report to the International Joint Commission (IJC) recommended two alternative plans for water resource management in the Okanagan-Similkameen Basin; a major feature of both plans was multipurpose storage on the Similkameen. The first alternative included a 79-m (259.2 ft) high dam at Shanker’s Bend, which would back water in the Similkameen River from a point 12 km (7.46 mile) upstream of Oroville, Washington, to Cawston, B.C. The second alternative called for a lower dam at Shanker’s Bend, which would back up the water to the international border, and included a series of additional dams on the Similkameen Table 1 summarizes the pertinent site data and Figure 2 indicates their locations.
Table 1  Summary of IJC Study Storage Site Data

<table>
<thead>
<tr>
<th>Site</th>
<th>Total Storage (Acre-Feet)</th>
<th>Usable Storage (Acre-Feet)</th>
<th>Total Cost (1955$)</th>
<th>Reservoir Elev. (ft)</th>
<th>Reservoir Elev. (m)</th>
<th>Hydro Capacity (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shanker's Bend High Dam</td>
<td>1,700,000</td>
<td>1,310,000</td>
<td>$42,689,000</td>
<td>1,289</td>
<td>392.9</td>
<td>84,000</td>
</tr>
<tr>
<td>Shanker's Bend Lower Dam</td>
<td>168,000</td>
<td>162,000</td>
<td>$19,085,000</td>
<td>1,175</td>
<td>358.1</td>
<td>11,000</td>
</tr>
<tr>
<td>Nighthawk</td>
<td>106,000</td>
<td>106,000</td>
<td>not determined</td>
<td>1,170</td>
<td>356.6</td>
<td>0</td>
</tr>
<tr>
<td>Ashnola</td>
<td>62,000</td>
<td>62,000</td>
<td>$4,877,000</td>
<td>1,510</td>
<td>460.2</td>
<td>0</td>
</tr>
<tr>
<td>Bromley</td>
<td>405,000</td>
<td>273,000</td>
<td>$14,320,000</td>
<td>2,070</td>
<td>630.9</td>
<td>12,000</td>
</tr>
<tr>
<td>Similkameen #3</td>
<td>18,000</td>
<td>18,000</td>
<td>not determined</td>
<td>2,720</td>
<td>829.0</td>
<td>3,700</td>
</tr>
<tr>
<td>Similkameen #4</td>
<td>25,000</td>
<td>25,000</td>
<td>$2,432,000</td>
<td>3,370</td>
<td>1,027.1</td>
<td>1,900</td>
</tr>
<tr>
<td>Similkameen #5</td>
<td>55,000</td>
<td>55,000</td>
<td>$3,396,000</td>
<td>3,450</td>
<td>1,051.5</td>
<td>0</td>
</tr>
<tr>
<td>Similkameen #6</td>
<td>73,000</td>
<td>73,000</td>
<td>$5,850,000</td>
<td>3,660</td>
<td>1,115.5</td>
<td>0</td>
</tr>
<tr>
<td>Ashnola River #1</td>
<td>48,000</td>
<td>48,000</td>
<td>$5,028,000</td>
<td>3,725</td>
<td>1,135.3</td>
<td>0</td>
</tr>
<tr>
<td>Ashnola River #2</td>
<td>22,000</td>
<td>22,000</td>
<td>$1,473,000</td>
<td>3,850</td>
<td>1,173.4</td>
<td>0</td>
</tr>
<tr>
<td>Tulameen</td>
<td>12,000</td>
<td>12,000</td>
<td>$1,746,000</td>
<td>2,800</td>
<td>853.4</td>
<td>0</td>
</tr>
</tbody>
</table>
1.2.1.2 Similkameen Basin Storage Study (1981)

This study was a compilation of previous studies that investigated storage requirements and potential storage developments from existing lakes. The potential storage of the existing lake sites under investigation was about 31,000 acre-feet (38,238,500 m³); however, to satisfy the total estimated demand for both irrigation and industrial purposes, the study indicated that an additional 48,000 acre-feet (59,208,000 m³) of storage would be required. As many of these lakes have homes around them, the study indicated that properties would need to be acquired to allow the levels of the lakes to be raised for storage augmentation.

In addition to compiling the total irrigable acreage and water demand for the Similkameen Basin, similar information was compiled for each of ten sections, representing a tributary of the Basin or a portion thereof. The water demand for irrigation use would be from May 1st through Sept. 15th.

Table 2 summarizes the total potential irrigable lands and associated water demand that could occur in the future.

### Table 2  Summary of Irrigable Acreage and Water Requirements (For Sprinkler Irrigation)

<table>
<thead>
<tr>
<th>Section</th>
<th>Area Description</th>
<th>Area</th>
<th>Total Requirements</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(acres)</td>
<td>(ha)</td>
<td>(acre-ft)</td>
</tr>
<tr>
<td>1</td>
<td>Similkameen River (from Hedley downstream to International Boundary)</td>
<td>20,318</td>
<td>8226</td>
<td>53,336</td>
</tr>
<tr>
<td>2</td>
<td>Keremeos Creek</td>
<td>1,203</td>
<td>487</td>
<td>3,074</td>
</tr>
<tr>
<td>3</td>
<td>Similkameen River (Upstream of Hedley)</td>
<td>7,930</td>
<td>3211</td>
<td>19,153</td>
</tr>
<tr>
<td>4</td>
<td>Hayes Creek</td>
<td>3,260</td>
<td>1320</td>
<td>6,783</td>
</tr>
<tr>
<td>5</td>
<td>Summers Creek</td>
<td>872</td>
<td>353</td>
<td>1,672</td>
</tr>
<tr>
<td>6</td>
<td>Allison Creek</td>
<td>10,205</td>
<td>4132</td>
<td>19,484</td>
</tr>
<tr>
<td>7</td>
<td>Upper Otter Creek (Upstream of Thalia)</td>
<td>2,227</td>
<td>902</td>
<td>3,291</td>
</tr>
<tr>
<td>8</td>
<td>Lower Otter Creek (From Otter Lake to Thalia)</td>
<td>2,389</td>
<td>967</td>
<td>3,779</td>
</tr>
<tr>
<td>9</td>
<td>Tulameen River</td>
<td>1,885</td>
<td>763</td>
<td>4,366</td>
</tr>
<tr>
<td>10</td>
<td>Wolf Creek</td>
<td>828</td>
<td>335</td>
<td>1,290</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>51,117</td>
<td>20695</td>
<td>116,228</td>
</tr>
</tbody>
</table>

The potential total water use was estimated as shown in Table 3. At the time of the study, there was a Canadian license for water consumption of 155 cfs (4.4 m³/s) for mining and 1.5 cfs (0.042 m³/s) for water works. American water licenses for irrigation were variable and ranged from 151.6 cfs to 213.6 cfs (4.29 m³/s to 6.05 m³/s). In addition there was a hydro license to use 250 cfs (7.08 m³/s). The study indicated a deficiency of water availability of 79,462 acre-feet (98,016,377 m³), which principally occurred from July through Sept. 15th.
From an investigation of potential storage sites within the Similkameen Basin, the following sites were identified, which had a total existing storage of 10,110 acre-feet (12,470,685 m³) and potential for development of 31,074 acre-feet (38,329,779 m³):

1. Lightning Lake;
2. Allison Lake;
3. Yellow Lake;
4. Nickle Plate Lake plus Winters Creek Diversions
5. Wolf Lake system (e.g. Wolf, Issitz, Lorn and Willis);
6. Davis Lake system;
7. Otter Lake;
8. Missoula Lake plus Dillard Creek Diversion; and
9. Chain Lake system (e.g. Chain, Link and Osprey).

It should be noted that from a subsequent economic evaluation of the Similkameen Storage Project (Griffing May 1992), it was concluded that actions taken as a result of earlier studies resulted in pressurization of all major irrigation districts and improved efficiencies throughout the basin, which may have addressed some of the immediate concerns of water deficits.

1.2.1.3 Princeton Power & Light (PP&L) Hydroelectric Investigations

Studies were initiated in 1990 to investigate the pre-feasibility of hydroelectric development in the upper Similkameen Basin at prospective dam sites (Stewart-EBA Consulting Ltd.). The sites investigated (Table 4) were different from those indicated in earlier studies and were downstream of the Similkameen River confluence with the Pasayten River. The sites were selected based on the steepness of the river channel in this river reach, the significant portion of the drainage in the Basin occurring upstream of these sites and based on a site reconnaissance that indicated minimal overburden cover of the rock at each dam site and an apparent bedrock profile, which minimizes construction quantities, but also did not present the probability of high foundation preparation costs.
Table 4  Summary of Upper Similkameen River Dam Sites for Hydroelectric Development

<table>
<thead>
<tr>
<th>Site</th>
<th>Dam Height</th>
<th>Normal Operating Pool Elev.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ft.</td>
<td>m</td>
</tr>
<tr>
<td>Pumphouse</td>
<td>120; 290</td>
<td>36.5; 88.4</td>
</tr>
<tr>
<td>Copper Mountain</td>
<td>180; 480</td>
<td>54.8; 146.3</td>
</tr>
<tr>
<td>Saturday Creek</td>
<td>300</td>
<td>91.4</td>
</tr>
</tbody>
</table>

The pre-feasibility study investigated three alternative plans in combination of dams and tunnels that developed the hydraulic head between El. 3050 and El. 2410 feet (929.6 m and 734.5 m). The upper boundary was limited to El. 3050 ft (929.6 m) so as to not encroach into a BC Forest Service Recreation Park. Below El. 2810 ft (56.4 m), the river gradient became flatter, which dramatically increased the cost of developing the hydroelectric development below this point. The alternative plan that was recommended for development was comprised of a 500-foot-high (152.4 m) rockfill dam at the Copper Mountain site, a 13,000-foot-long (3,962.2 m) headrace tunnel, a short steel penstock, and a 22 MW powerhouse structure – all at an estimated capital cost of $70 million (1992 price level).

A later study focused on a single dam site (Pumphouse) with a normal maximum pool level at three alternative levels:

- El. 2800 ft (853.4 m) [39,700 acre-ft (4,8969,950 m³) storage from 300-ft (91.4 m) high dam];
- El. 2925 ft (891.5 m) [120,000 acre-ft (148,020,000 m³) from 425-ft (129.5) high dam]; and
- El. 3050 ft (929.6 m) [297,300 acre-ft (366,719,550 m³) from 550-ft (167.6 m) high dam].

The selected project for possible development included the large dam with installed capacity of 60 MW, which could produce approximately 228.9 GWh on an average annual basis. This estimate was based on the hydrologic period 1965-1990. Project construction costs exclusive of engineering and contingencies were estimated to be $85,933,000.

1.2.1.4 Hatch Energy Update of PP&L Study

An independent engineering review of the 1994 Princeton Power & Light (PP&L) study by Hatch Energy in August 2006 revealed a higher cost estimate of project development with a 600-foot (182.9 m) high dam at the Pumphouse location once engineering, contingencies and financing costs were included. Hatch Energy also considered a smaller 240-foot (73.1 m) high concrete arch dam at a site 300 feet (91.4 m) upstream with a 20 MW installation. The addition of a 3,000-foot (914.4 m) long tunnel would increase the size of the downsized hydroelectric project to 28 MW.
2. Watershed Site Conditions

2.1 General
The Similkameen River drains about 7,600 square kilometres (2,934.3 sq. mi) of British Columbia’s southwestern interior to its confluence with the Okanagan River. Rising in the Cascade Mountains, the river flows over 200 km (124.3 mile). The upper reaches of the river are fast flowing and the valley walls are steep; in the lower reaches from Keremeos to the international border, the valley widens and flattens.

The Basin has one distinct highwater event per annum; during May and June over 60% of the Basin’s annual runoff occurs as a result of snowmelt. This late spring freshet is followed by rapid decline in flows during July and August, often creating a surface water deficit for water users. Fall and winter flows remain well below average for the year, even though low-elevation precipitation may result in moderate rises in the river. Mean annual runoff average 230 mm (9") over the entire Basin; however, most of this contribution originates above El. 1,070 m (3,500 ft).

Table 5 presents a summary of monthly mean discharges and extremes at the different gauging stations along the Similkameen River. As the data indicates, the runoff of the Similkameen River near Princeton represents about 37% of the river flow from 20% of the drainage. Figure 3 presents a map showing the location of these gauging stations and other weather stations within the Similkameen basin.

The Similkameen River is not known for its diversity or abundance of fish. There are no salmon or migratory steelhead due to natural falls at Enloe, Washington that creates an anadromous fish barrier.
### Table 5  Monthly and Annual Mean Discharges and Extremes of Discharge for the Period of Record of Selected Stations along the Similkameen River

<table>
<thead>
<tr>
<th>Station #</th>
<th>08NL007</th>
<th>08NL038</th>
<th>08NL006</th>
<th>08NL022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Station Name</td>
<td>Similkameen R. near Princeton</td>
<td>Similkameen R. near Hedley</td>
<td>Similkameen R. near Keremeos</td>
<td>Similkameen R. near Nighthawk</td>
</tr>
<tr>
<td>Period of Record</td>
<td>1914-17; 1939-1965</td>
<td>1911-12; 1914-32</td>
<td>1911-27; 1928</td>
<td></td>
</tr>
<tr>
<td>Drainage Area (Km²)</td>
<td>1,850</td>
<td>5,590</td>
<td>5,960</td>
<td>9,190 (regulated)</td>
</tr>
<tr>
<td>(mi²)</td>
<td>714</td>
<td>2,158</td>
<td>2,301</td>
<td>3,548</td>
</tr>
<tr>
<td><strong>Monthly Mean Discharge</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan</td>
<td>5.3 (m³/s)</td>
<td>11.5 (m³/s)</td>
<td>13.3 (m³/s)</td>
<td>17.1 (m³/s)</td>
</tr>
<tr>
<td>Feb</td>
<td>5.5 (m³/s)</td>
<td>12.6 (m³/s)</td>
<td>13.7 (m³/s)</td>
<td>18.7 (m³/s)</td>
</tr>
<tr>
<td>Mar</td>
<td>6.1 (m³/s)</td>
<td>16.1 (m³/s)</td>
<td>16.7 (m³/s)</td>
<td>19.4 (m³/s)</td>
</tr>
<tr>
<td>Apr</td>
<td>17.5 (m³/s)</td>
<td>34.8 (m³/s)</td>
<td>48.6 (m³/s)</td>
<td>54.7 (m³/s)</td>
</tr>
<tr>
<td>May</td>
<td>87.1 sq.mi</td>
<td>3,075 cfs</td>
<td>6,603 cfs</td>
<td>209.0 (m³/s)</td>
</tr>
<tr>
<td>Jun</td>
<td>99.0 (m³/s)</td>
<td>3,495 cfs</td>
<td>7,380 cfs</td>
<td>201.0 (m³/s)</td>
</tr>
<tr>
<td>Jul</td>
<td>34.3 (m³/s)</td>
<td>1,211 cfs</td>
<td>63.8 (m³/s)</td>
<td>60.3 (m³/s)</td>
</tr>
<tr>
<td>Aug</td>
<td>9.0 (m³/s)</td>
<td>16.7 (m³/s)</td>
<td>17.6 (m³/s)</td>
<td>26.1 (m³/s)</td>
</tr>
<tr>
<td>Sep</td>
<td>5.9 (m³/s)</td>
<td>10.5 (m³/s)</td>
<td>13.1 (m³/s)</td>
<td>17.5 (m³/s)</td>
</tr>
<tr>
<td>Oct</td>
<td>7.3 (m³/s)</td>
<td>11.6 (m³/s)</td>
<td>17.4 (m³/s)</td>
<td>20.4 (m³/s)</td>
</tr>
<tr>
<td>Nov</td>
<td>8.3 (m³/s)</td>
<td>14.5 (m³/s)</td>
<td>17.2 (m³/s)</td>
<td>24.7 (m³/s)</td>
</tr>
<tr>
<td>Dec</td>
<td>7.2 (m³/s)</td>
<td>14.7 (m³/s)</td>
<td>13.1 (m³/s)</td>
<td>21.7 (m³/s)</td>
</tr>
<tr>
<td>Annual</td>
<td>24.6 (m³/s)</td>
<td>868 cfs</td>
<td>50.5 (m³/s)</td>
<td>55.2 (m³/s)</td>
</tr>
<tr>
<td>Maximum Daily Discharge (m³/s)</td>
<td>476 (m³/s)</td>
<td>16,807 cfs</td>
<td>929 (m³/s)</td>
<td>32,803 cfs</td>
</tr>
<tr>
<td>(May 72)</td>
<td>(May 72)</td>
<td>(May 28)</td>
<td>(Jun 72)</td>
<td>(Jun 72)</td>
</tr>
<tr>
<td>Minimum Daily Discharge (m³/s)</td>
<td>0.14 (m³/s)</td>
<td>2.92 (m³/s)</td>
<td>2.35 (m³/s)</td>
<td>3.68 (m³/s)</td>
</tr>
<tr>
<td>(Jan 40)</td>
<td>(Sep 70)</td>
<td>(Dec 29)</td>
<td>(Jan 74)</td>
<td></td>
</tr>
</tbody>
</table>
2.2 Water Data

To assist in possibly better understanding the Similkameen Basin, we reviewed stream gauging, precipitation and water quality data as available at http://scitech.pyr.ec.gc.ca at four points of interest on the Similkameen River and two on the Tulameen River.

2.2.1 Stream Gauging Data

As discussed above, four current WSC gauges operating stations on the Similkameen River and two on the Tulameen River were identified to provide historical information on the long term runoff characteristics of the watershed. The WSC gauges include the following:

- Similkameen River above Goodfellow Creek, 08NL070, DA = 407 km² (157.1 mi²);
- Similkameen River at Princeton, 08NL007, DA = 1,850 km² (714.3 mi²);
- Similkameen River near Hedley, 08NL038, DA = 5,590 km² (2,158.3 mi²);
- Similkameen River near Nighthawk, 08NL022, DA = 9,190 km² (3,548.3 mi²);
- Tulameen River below Vuich, 08NL071, DA = 256 km² (98.8 mi²); and
- Tulameen River at Princeton, 08NL024, DA = 1,760 km² (679.5 mi²).

The locations of the above noted stream gauges are shown on Figure 4. The historical hydrographs for each of the above noted stream gauges are provided on Figures 5 to 8. Also provided on the above figures are the 10 year annual, the 10 year summer (May to October), and the 10 year winter (November to April) moving averages. The moving averages are provided to show the historical trends of the streamflow to determine whether flows are increasing or decreasing over the period of record. Data for the Goodfellow (Similkameen) and Vuich (Tulameen) gauging stations have not been provided due to their relative short period of record as well as their being the furthest upstream gauges having limited drainage areas. In all cases, the trend is towards reduced annual runoffs, and in particular, greater reduced summer runoffs. Winter runoffs have tended to increase slightly; this may be due to global warming where a greater percentage of the precipitation occurs as rainfall rather than snowfall. However, the overall trends indicate a reduced annual runoff. Reduced runoff would directly impact the hydro generation with reduced potential.

2.2.2 Precipitation and Temperature

Similarly, climatic data related to precipitation and temperature was downloaded from two local weather stations, one at Princeton Airport and secondly, one at Osoyoos. Figures 9 and 10 provide the precipitation and temperature analysis for the Princeton station; while Figures 11 and 12 provide the precipitation and temperature analysis for the Osoyoos station. At both Princeton and Osoyoos, the trend is for increased temperatures throughout the year, both summer and winter. At Princeton, the overall annual trend for precipitation is a slight increase; however, during the winter period the trend is for a decrease in precipitation. At Osoyoos, the trend is for increased precipitation throughout the year, both summer and winter. Increased precipitation would tend to suggest increased watershed runoff; however, this is contrary to the recorded data within the Similkameen watershed. This is perhaps due in part to increased rates of evaporation and evapotranspiration with
increased temperature. Also, there may have been increased water diversion from the rivers for water supply and irrigation demands over time.

2.2.3 Water Quality
We would expect that seasonal releases from stored water could have a significant benefit to fish habitat, which would represent considerable value to the Similkameen River Basin and further downstream to the Okanagan River Basin. Such benefits should be estimated in terms of improved survival fish because of increased summer flows and reduced temperatures in late summer and fall. Water quality data is not recorded at any of the above mentioned streamflow gauges; however, the water quality would be expected to improve downstream of the proposed hydroelectric installation because of increased flow releases during the summer and early fall. Adverse water quality from proposed mining operations in the basin is not anticipated as tailing ponds will be implemented with any potential mining operation and due to current legislation, all effluent released to natural stream courses will require strict monitoring measures.

2.3 Water Supply
Water supply in the Basin is from the Similkameen River and its tributaries. Most of the water is taken from a shallow groundwater well system that is mostly recharged by the Similkameen River, which is a meandering stream with a coarse gravel bottom, which were deposits from when a dam of ice and glacial debris impounding a glacial lake suddenly broke about 10,000 years ago. These floods were essentially erosive events but, at the end of the flood, large amounts of sand and gravel were deposited, especially at places where the valleys became wider. The upper aquifer may well be torrential gravel which is usually highly permeable.

Two well fields (East and West) supply the Keremeos Irrigation District, which is the principal water user in the Similkameen Watershed. The East Well Field consists of 6 wells with a total pump capacity of about 438 L/s (8,324,688 GD). The West Well Field consists of 4 wells with a total pump capacity of 263 L/s (4,998,614 GD). All wells are 400 mm (15.7") diameter except for one 200 mm (7.9") well in each of the well fields. The 400 mm (15.7") wells are completed with 300 mm (11.8") pipe size stainless steel spiral-wound well screens. Specific capacities of the 400 mm (15.7") wells vary from 30 L/s/m (1.13/GD/ft.) to 66 L/s/m (382,324 GD/ft) of drawdown.

The nature of the surficial deposits filling the Similkameen Valley is known mostly from many water wells that have been constructed in the near-surface aquifer. A log from a 126-m-deep (413.4 ft.) test well shows two other gravelly sand aquifers separated by till below the upper gravel aquifer. However, the upper aquifer which extends from near surface to 43 m (141.1 ft.) is very productive so it is the only one being exploited.

A large irrigation scheme that was built for the Keremeos Irrigation District in 1930 initially diverted water from the Ashnola River, a large tributary of the Similkameen River. When the irrigation system required major repairs in 1967, the irrigation water from groundwater was found to be less than repairs to the Ashnola Surface Water System so the system was reconstructed using two well fields to supply the entire demand. The present system was put into operation in 1973; two additional wells were added and minor changes to the system were made in 1978.
2.4 Water Demand

2.4.1 General

Existing studies of water demand within the Similkameen Basin appear to be lacking. While recorded average consumption of water in the town of Princeton is currently about (0.045 m³/s (1.6 cfs)) Keremeos Irrigation District does not record water taken from the Similkameen River; however, from pump capacity ratings, we know that the demand does not exceed 700 litres/sec (~25 cfs). As the principal areas of current and future water demand would center on agricultural and mining, we would recommend that further studies be performed that would investigate current water demands from these economic sectors.

A Similkameen Basin Storage Study (Harris 1981) provided estimates of possible flow deficiency from a critical dry hydrological year based on future demand potential, which is summarized in Table 6. The deficiency is considered to be the volume of storage release required to supplement the natural flow. Deficiency does not include Canadian entitlement. The potential Canadian Demand is those values shown in Table 3. The American Demand is a combination of irrigation demand and hydroelectric demand, although the hydroelectric water demand in August and September was reduced considerably to only consider water for firm energy, and not for secondary energy. Although, not explicitly stated, the water demand for hydro generation would appear to have been for the Enloe hydroelectric project, which would have had a water license of 450 cfs (12.7 m³/s), based on maximum flow at rated output. The Enloe Project has not been operating since 1958, but the Okanagan PUD has a new license for a 9 MW installation with a design flow of 1600 cfs (45.3 m³/s).

It should be noted that the flows recorded at the Nighthawk stream gauging station in 1540 represented the driest stream flow on record. Nevertheless, water supply deficits would be shown to occur for most if not all dry years in August through mid-September based on the potential water demand values shown in Table 6.

Table 6 Potential Similkameen Basin Flow Deficiency in Critical Hydrologic Water Year

<table>
<thead>
<tr>
<th>Month</th>
<th>Natural Flow Year 1940</th>
<th>American Demand</th>
<th>Canadian Entitlement</th>
<th>Potential Canadian Demand</th>
<th>Total Deficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>cfs m³/s</td>
<td>cfs m³/s</td>
<td>cfs m³/s</td>
<td>cfs m³/s</td>
<td>Flow (cfs) m³/s</td>
</tr>
<tr>
<td>April</td>
<td>2033 57.6</td>
<td>448.4 12.7</td>
<td>151.5 4.3</td>
<td>208 5.9</td>
<td>0 0 0 0 0</td>
</tr>
<tr>
<td>May</td>
<td>5022 142.2</td>
<td>401.6 11.4</td>
<td>151.5 4.3</td>
<td>598 16.9</td>
<td>0 0 0 0 0</td>
</tr>
<tr>
<td>June</td>
<td>2772 78.5</td>
<td>426.6 12.1</td>
<td>151.5 4.3</td>
<td>649 18.4</td>
<td>0 0 0 0 0</td>
</tr>
<tr>
<td>July</td>
<td>660 18.7</td>
<td>463.6 13.1</td>
<td>151.5 4.3</td>
<td>672 19.0</td>
<td>475.6 13.5 29,487 36.4</td>
</tr>
<tr>
<td>August</td>
<td>293 8.3</td>
<td>243.4 6.9</td>
<td>58.6 1.7</td>
<td>635 18.0</td>
<td>576.4 16.3 35,737 44.1</td>
</tr>
<tr>
<td>Sept. 1-15</td>
<td>202 5.7</td>
<td>161.6 4.6</td>
<td>40.4 1.1</td>
<td>515 14.6</td>
<td>474.6 13.4 14,238 17.6</td>
</tr>
</tbody>
</table>


2.4.2 Water Licenses

Table 7 provides a summary listing of the water licenses for various water uses including domestic, irrigation, mining and power generation / storage on the Similkameen River. If fully utilized, the overall domestic waterworks use rate would represent an average withdrawal rate of 31.8 cfs (0.9 m³/s); irrigation would represent an average withdrawal rate of 35.3 cfs (1.0 m³/s) assuming the irrigation season would extend from July 1st to September 30th; and mining would represent an average withdrawal rate of 17.7 cfs (0.5 m³/s). The water usage rate for power generation would not result in an actual withdrawal rate as the water is returned to the natural river channel immediately downstream of the power plant. Figure 13 presents an accumulation of the water licenses which has been relatively stagnant in growth since 1970. Additional details with respect to the individual water licenses are provided in Appendix A.

Table 7  Summary of Water Licenses

<table>
<thead>
<tr>
<th>Application</th>
<th>No. of Licenses</th>
<th>Quantity</th>
<th>Unit</th>
<th>Quantity in m³/s</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Municipality</td>
<td>21</td>
<td>73,500</td>
<td>GD</td>
<td>0.004</td>
<td>Year Round</td>
</tr>
<tr>
<td>Waterworks</td>
<td>1</td>
<td>9,855,000</td>
<td>GY</td>
<td>0.001</td>
<td>Year Round</td>
</tr>
<tr>
<td>Waterworks</td>
<td>1</td>
<td>2,000,000</td>
<td>GD</td>
<td>0.11</td>
<td>TYP. July 1st to Sept 30th</td>
</tr>
<tr>
<td>Waterworks</td>
<td>1</td>
<td>21,880,000</td>
<td>GD</td>
<td>1.15</td>
<td>TYP. Oct 1st to June 30th</td>
</tr>
<tr>
<td>Irrigation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Irrigation</td>
<td>84</td>
<td>8,611</td>
<td>AF</td>
<td>1.34</td>
<td>TYP. July 1st to Sept. 30th</td>
</tr>
<tr>
<td>Local Auth.</td>
<td>11</td>
<td>18,973</td>
<td>AF</td>
<td>2.95</td>
<td>TYP. July 1st to Sept. 30th</td>
</tr>
<tr>
<td>Mining</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydraulic</td>
<td>2</td>
<td>2</td>
<td>CFS</td>
<td>0.05</td>
<td>Year Round</td>
</tr>
<tr>
<td>Process</td>
<td>3</td>
<td>8,034,000</td>
<td>GD</td>
<td>0.42</td>
<td>Year Round</td>
</tr>
<tr>
<td>Power</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>General</td>
<td>1</td>
<td>1,200</td>
<td>CFS</td>
<td>33.98</td>
<td>Year Round</td>
</tr>
<tr>
<td>Storage</td>
<td>1</td>
<td>300,000</td>
<td>AF</td>
<td>11.74</td>
<td>Year Round</td>
</tr>
</tbody>
</table>

Notes:
GD: Gallons per Day
GY: Gallons per Year
AF: Acre Feet Per Annum
CFS: Cubic Feet Per Second

2.4.3 Land Use

Land use patterns within the Similkameen Basin help establish water needs but also set boundaries as to where storage dams would be of most use and where their locations could create a negative impact due to the displacement of communities or land use. Figures 14 and 15, taken from Environmental Canada Environmental Service report (Sherwood 1981), presents, respectively, a map of electoral areas and communities and a map of agricultural land reserves and parks. These figures generally support the contention that if any storage reservoir were to be built in the basin, the location of a large dam would be more beneficial in the upper Similkameen Basin upstream of the numerous Indian Reserves and the agricultural land reserves.
Land use within the basin generally consists of agriculture, mining, and forestry industry. Tourism is also important and is supported by a number of Provincial Parks. An updated study of the one prepared by the Environmental Conservation Services is needed to better assess the current land use patterns within the Basin.

2.4.4 Agricultural

Agriculture is generally ranked the third largest industry within the Basin. Much of the agriculture is from fruit trees. Keremeos has a fruit processing plant, packing plant, cold storage facility and five local irrigation districts. Most of the arable lands are found in the valley bottoms (see Figure 15). Irrigation is essential during the summer months for most crops. However, without provision for storage or groundwater supplies, the potential for agricultural expansion is limited (Sherwood 1981).

The Lower Similkameen Indian Band has eight reserves between the Ashnola River and the international boundary. The area is capable of sustaining a wide variety of crops, but irrigation is essential. The Upper Similkameen Band has nine reserves in the Princeton-Hedley area. Several reserves are subject to periodic flooding and resulting erosion (Sherwood 1981). Soils are stony and unsuitable for agriculture on most reserves, but hay and forage crops are grown in some areas.

2.4.5 Mining

The Similkameen Basin is part of a generally highly mineralized area of North America (Sherwood 1982). Local areas of high mineral potential in the Basin are: the Tulameen River; the Similkameen Valley from Hedley to Princeton; and the areas south of and including the Copper Mountain mine. The Copper Mountain mine was recently purchased, and the Copper Mountain Mining Company is in the process of reestablishing the mine in Pit Nos. 1, 2 and 3 and will be hiring a large number of employees to operate the mine.

This mine and others within the Basin are dependent upon either Similkameen River or the groundwater for their milling process, and the demand can be appreciable. We do not know what is the current water demand from mining activities, however, we are aware of what an upper limit might be from the previous investigation by the Environmental Ministry of Mines.

The Copper Mountain Mine is adjacent to a potential reservoir storage project in the Similkameen River upstream of the town of Princeton. From Copper Mountain, the mined ore would be transported over the Similkameen River by a suspended conveyor belt to the Ingerbelle Mill. Here it is crushed and ground to a fine powder, treated with chemicals, then filtered and dried, producing a concentrate, which is then shipped elsewhere for further treatment. The tailings from the plant flow by gravity to a 1,312 ft. (400-m-long) suspension bridge, which crosses the Similkameen River at a point just downstream of a pump house and travels to a tailings pond or cyclone station. Water is reclaimed from the pond and pumped back to the concentrator. Additional water, mostly for cooling, would be withdrawn from the Similkameen and tributary creeks. No waste material would be discharged into the river.

As the Similkameen River crossing occurs downstream of the three storage project locations identified in the EBA study, there does not appear to be a potential impact toward a storage reservoir development within the proposed sites.
2.4.6 Industrial
The forestry industry has historically been a significant factor in the economy of the Similkameen Basin (Sherwood 1983). The Basin lies in the southwestern corner of the Kamloops Forest Region and comprises of tow Timber Supply Areas: Okanagan and Merritt Weyerhaeuser Canada Ltd. operates a large sawmill in Princeton and is the largest employer in the region.

2.5 Flood Control
Peak flood levels in the Similkameen Basin generally occur between early May and mid-June as increasing temperatures melt the accumulated snowpack in the mountainous areas. The highest flood levels on record for locations on the mainstem Similkameen River occurred in 1972 when rapidly rising temperatures during late May acted on an exceptionally heavy snowpack to produce peak flows of 16,607 cfs (476 m³/s) at Princeton (upstream of the Tulameen River), 32,803 cfs (929 m³/s) near Hedley and 44,844 cfs (1270 m³/s) near Nighthawk. The flood level near Princeton was estimated to have been a 120-year return-period flood, with the flows at Hedley and Nighthawk being greater than a 200-year return-period flood. Figure 16 presents a hydrograph of the spring flood of record at Princeton, near Hedley and near Nighthawk. If a multi-storage reservoir project with 1,440 acre-feet (1,776,240 m³) of useable storage were to be constructed in the upper Similkameen Basin, Figure 17 presents an estimate by Griffing (Nov. 1992) of an outflow hydrograph at the Princeton, Hedley and Nighthawk locations using a COE HEC-5 operational mod. The outflow hydrographs were more significant at Princeton, but provided some measurable level of benefits to the other parts of the Basin. It should be noted that the reservoir did not start with minimum pool when routing the hydrograph through the reservoir, but considered operational objectives that would fill the reservoir toward the end of the freshet snowmelt period.

Riverbank protection extends intermittently along the Similkameen River from Princeton to the Lower Similkameen Indian Reserve (Sherwood 1983). The dykes and ripraping were constructed during and after the 1972 flood event. Sections of the Indian Reserve to the international boundary were also dyked under the Agricultural and Rural Development Subsidiary Agreement (ARDSA) for both flood control and agricultural.

2.6 Water Storage Needs
Previous studies have indicated a need for developing a large multipurpose storage project with the indication that up to 80,000 acre-feet (98,680,000 m³) could be needed for water supply within the Similkameen and Okanagan basin areas during the July-September period. For flood control, the storage of a multipurpose project would likely need to be greater than 80,000 acre-feet (98,680,000 m³) to begin to provide some benefits of reducing flood damages within the Basin, as evidenced from the Griffing Consultants hydrology analyses (Nov. 1992). The greater the storage reservoir, it stands to reason that water quality for fisheries would be improved, especially during the late summer months when colder water could be withdrawn from the reservoir and low flow levels would increase considerably below a storage dam. It should be noted that while irrigable acreage that have interruptible rights with cut-off dates of September 15th or earlier could benefit from increased late summer flows, such flows can not be guaranteed due to prior rights held by the Department of Ecology because of prior rights to by the Department of Fisheries and Indian Tribes.
increased in late summer thus lessening political pressure to possible receive additional water during this period.

With increased storage comes greater potential for energy production as high flows during the freshet months are stored for more steady state release in the other months when flow levels are not as high. Furthermore, energy production in the region is more valuable during the non-freshet months; there is typically a surplus of energy during the freshet months when many hydro facilities are operating at high capacity levels. This surplus generally results in a low-value of energy.

With the future redevelopment of the Enloe Hydroelectric Project and the existence of nine Columbia River dams between Wells and Bonneville, considerable headwater benefits would result in improved reservoir operation of these other hydro projects and increase their respective revenue from a large storage project in the Similkameen Basin.
3. Potential Storage Sites for Development

3.1 Shanker’s Bend Site
The Okanogan PUD is currently undertaking an investigating of a multipurpose storage project on the Similkameen River at Shanker’s Bend, which would be located just upstream of Enloe Reservoir. Three different sized storages are being considered, with the medium size reservoir being defined as the limit for not extending the project reservoir into Canada. The storage sizes being investigated include:

- A high dam, capable of impounding a reservoir of about 1.7 million acre-feet (2097 Mm³) to a maximum pool elevation of 1,289 feet (393 m);
- A medium dam, capable of impounding a reservoir of about 168,000 acre-feet (207.23 Mm³) to a maximum pool elevation of 1,175 feet (358.1 m); and
- A low dam, capable of impounding a reservoir of about 50,000 acre-feet (61.68 Mm³) to a maximum pool elevation of 1,155 feet (352.0 m).

3.2 Enloe Hydrc Project Site
The Public Utility District No. 1 of Okanogan County (District) proposes to restore hydropower generation at Enloe Dam on the Similkameen River. Enloe Dam is a 54-foot high (16.5 m), 315-foot (96.0 m) long concrete gravity arch structure designed to act as an overflow spillway. The spillway crest length is 276 feet (84.1 m). Enloe Dam impounds a small reservoir approximately two miles long by 250 feet wide (76.2 m); with an average depth of 8.4 feet (2.6 m) at the existing dam crest elevation of 1444.3 feet (318.3 m). The dam was constructed to provide hydro power (3.2 MW), but was decommission in July 1958, when less expensive energy became available to Okanagan PUD from BPA projects. The PUD currently has a license application to refurbish Enloe dam and add headworks, penstocks and a powerhouse structure containing two Kaplan turbine units with a total installed capacity of 9.0 MW. The hydraulic capacity of the plant would be approximately 1600 cfs (45.3 m³/s).

The project is proposed to be a run-of-river project, but with no storage or peaking operation. The average annual generation is estimated to be 45.0 GWh, which results in a 57% capacity factor.

3.3 Assessment of Dam Sites within Canada
As the intent of this study was to provide better definition to the benefits of water supply, flood control, ecological resource improvement and hydro power from a Similkameen/Tulameen storage dam within the Similkameen watershed and the Okanagan Valley below the confluence of the two rivers, we only made a cursory review of tributaries off of the Similkameen River. Further investigations of dam sites previously identified in Table 1 may be warranted.

As indicated in Section 1.2, storage considerations in the Similkameen River Basin have been evaluated off and on for more than 60 years, principally for providing increased availability of water for potential irrigation demand. Expansion of storage from a large number of existing lakes had been evaluated early on in the 1900s in order to meet growing irrigation demands. Generally, those early studies concluded there was little potential for new storage sites within the basin.
previously proposed, either from drawdown or from construction of low-level embankment dams (Harris 1981). With such a plan, water could be provided to a larger area of suitable agricultural lands within the Basin than would not be possible from a single storage project. However, this plan was not adopted as it would have required provincial funding; the sites provided little potential for hydroelectric development that often provides important revenue base for supporting multi-purpose storage projects.

Of the larger storage sites previously surveyed in the 1955 IJC study, a few stood out, e.g. Similkameen 3 (164,000 ac-ft storage) (202.3 Mm³); Bromley (273,000 ac-ft storage) (336.7 Mm³), Ashnola (62,000 ac-ft storage) (76.4 Mm³) and Shanker’s Bend (1,310,000 ac-ft usable storage) (1616 Mm³) (see Figure 2). The upper Similkameen and Ashnola dam sites, as listed in Table 1, encroached into Provincial Parks (see Figure 15), which may preclude their construction. While the Bromley and Ashnola dam sites on the mainstem of the Similkameen River were identified as potentially viable storage sites, they are no longer socially or economically feasible under current settlement patterns and land tenures. Through the process of elimination, the dam site with the least opposition for development, yet appears to provide the greatest potential of hydro power, flood control, water supply and water quality improvement would seem to be from the Similkameen #3 dam site. This dam site was the area of more detailed feasibility investigation in the early 1990’s.

A dam site at a single location as proposed by PP&L would appear to be a good choice for the following reasons:

- The dam site on the mainstem of the Similkameen River with a 1580 km² (610 sq. mile) drainage captures more than 1/3 of the total Similkameen mean flow;
- The dam site is high enough in the upper Similkameen Basin to potentially meet the desired Basin attributes of increased water supply, flood control, ecological flow improvement and hydro power development.
- The steep canyon walls of the Similkameen help to minimize the cost of dam construction by reducing the volume of materials required, which helps reduce the cost of hydroelectric development;
- The mean river gradient of 0.0083 is steeper than the lower Similkameen channel, which may help to improve the feasibility of a hydroelectric site; and
- The site appears to avoid impact to any communities or First Nation lands. There appears to be no requirement of relocation of roads, utilities and homes.

A potential drawback of the PP&L selected dam site is that unless the dam is very high, there may not be sufficient storage to significantly improve flood control, water supply and water quality. The dam sites investigated by PP&L are located in a narrow canyon that minimizes storage potential for moderately high dams; however, the cost of dam development becomes less costly for narrow sites as the volume of materials for construction is reduced. A large dam with significant reservoir storage may also appreciably increase the total revenue from hydroelectric production due to shifting energy to the low-flow months when the value of energy is highest.
Besides the Upper Similkameen Dam site, the other dam site with potential promise for providing storage is at the Shanker's Bend on the Similkameen River. This site is on the U.S. side of the border and is undergoing further investigations by the Okanogan PUD.

The Ashnola Basin provides about 1/3rd of the flow that the Similkameen River provides near the Princeton stream gage. The river segment between Cathedral Park in the upper basin and near the confluence is significantly steeper than for the Similkameen River dam sites investigated by PP&L. The site might be viable for hydro generation, but storage opportunities within this river reach appear minimal. In any case, the ISC has indicated that land tenure, social and environmental issues eliminate the Ashnola from further consideration as a potential dam site.

### 3.4 Upper Similkameen Storage Sites

#### 3.4.1 Summary of initial Stewart-EBA Pre-Feasibility Study

In 1990, Stewart-EBA Consulting, Ltd. performed a pre-feasibility study of the dam sites which had the greatest potential for hydroelectric development in the Similkameen River Basin, which were those sites located above the town of Princeton but below the limits of the Provincial Park that is located near the confluence of the Pasayten River. Accordingly, EBA evaluated three dam sites and combine the dams into cascading hydroelectric development plans, which would maximize the available hydraulic head between El. 3050 ft. (930 m), which represented the lower boundary of a Forestry Park, and El. 2410 ft. (735 m), which represents the egress point of a narrow canyon with a steep river gradient. Downstream of this point the river gradient flattens making it more costly for hydroelectric development.

The three development plans were:

- Plan #1 comprised of a 120-ft-high (36.5 m) Pumphouse Dam Site; a 180-ft-high (54.8 m) Copper Mountain Dam Site; a 300-ft-high (91.4 m) Saturday Creek Dam Site; six units with a total installed capacity of 25 MW;
- Plan # 2 comprised of a 290-ft-high (88.4 m) Pumphouse Dam Site; a 300-ft-high (91.4 m) Saturday Creek Dam Site; four units with a total installed capacity of 24 MW; and
- Plan # 3 comprised of a 120-ft-high (36.5 m) Pumphouse Dam Site; a 480-ft-high (146.3 m) Copper Mountain Dam Site; four units with a total installed capacity of 22 MW.

Of the three plans, Plan #3 showed the highest internal rate of return (IRR) on investment, predominantly from the Copper Mountain Dam component.

#### 3.4.2 Review of EBA Feasibility Study Dam Site

The feasibility study focused on developing a single dam at the Pumphouse site for hydroelectric development and considered three different dam heights, each with different installed capacities of between 35 and 60 MW. The dam heights for the three cases were stated to be 300 feet (91.4 m), 425 feet (129.5 m) and 550 feet (167.6 m). However, actual dam heights could be as much as 50-ft higher (15.2 m) when considering potential dam foundation and dam crest freeboard for spillway capacity requirements. EBA assumed that the spillway would only need to pass the 100-year-flood...
frequency; however, each will need to demonstrate that it can safely pass the probable maximum flood (PMF), which would be a considerably higher flood.

The principal statistics of these alternatives are summarized in Table 8.

<table>
<thead>
<tr>
<th>Option</th>
<th>Dam Height ft</th>
<th>Dam Height m</th>
<th>Max Res. Elev. ft</th>
<th>Max Res. Elev. m</th>
<th>Min Res. Elev. ft</th>
<th>Min Res. Elev. m</th>
<th>Usable Storage (acre-feet)</th>
<th>Usable Storage Mm³</th>
<th>Plant Capacity MW</th>
<th>Plant Generation GWh</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td># 1</td>
<td>350</td>
<td>106.6</td>
<td>2,799.3</td>
<td>853.2</td>
<td>2,685.9</td>
<td>818.6</td>
<td>31,700</td>
<td>39.1</td>
<td>35</td>
<td>97.2</td>
<td>31.7%</td>
</tr>
<tr>
<td># 2</td>
<td>475</td>
<td>144.7</td>
<td>2,924.3</td>
<td>891.3</td>
<td>2,804.3</td>
<td>854.7</td>
<td>81,000</td>
<td>99.9</td>
<td>50</td>
<td>158.2</td>
<td>35.1%</td>
</tr>
<tr>
<td># 3</td>
<td>600</td>
<td>182.8</td>
<td>3,049.2</td>
<td>929.3</td>
<td>2,929.3</td>
<td>892.7</td>
<td>164,000</td>
<td>202.3</td>
<td>60</td>
<td>233.8</td>
<td>44.5%</td>
</tr>
</tbody>
</table>

The 1994 EBA study did not recommend any specific development from the options analyzed. It only presented the cost estimates for construction and energy estimates. The cost estimates of these projects, as estimated in the 1994 study are summarized in Table 9. The estimates did not include engineering, contingencies and financing costs. The study report recommended adding a 25% contingency to cover uncertainties of construction costs.

<table>
<thead>
<tr>
<th>Item</th>
<th>Option 1 (35 MW)</th>
<th>Option 2 (50 MW)</th>
<th>Option 3 (60 MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dam and Spillway</td>
<td>$15,802,000</td>
<td>$40,868,000</td>
<td>$61,748,000</td>
</tr>
<tr>
<td>Intake and Penstock</td>
<td>2,178,000</td>
<td>2,464,000</td>
<td>2,940,000</td>
</tr>
<tr>
<td>Powerhouse</td>
<td>16,625,000</td>
<td>19,475,000</td>
<td>18,995,000</td>
</tr>
<tr>
<td>Substation &amp; Transmission</td>
<td>2,250,000</td>
<td>2,250,000</td>
<td>2,250,000</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>$36,855,000</strong></td>
<td><strong>$65,057,000</strong></td>
<td><strong>$85,933,000</strong></td>
</tr>
</tbody>
</table>

1 Estimates do not include land, engineering, contingencies or financing costs.

3.4.2.1 Update of Cost Estimates for Pumphouse Dam Site

3.4.2.1.1 General

We have prepared an update of the EBA cost estimates, based on our review of the design and when considering current market conditions. The reconnaissance grade estimates were principally derived from empirical formulas and the use of more conservative assumptions than previously assumed in the 1994 feasibility study. We also evaluated an alternative concrete-arch dam at a site approximately 300 feet (91.4 m) upstream of the Pumphouse site. We have also considered the addition of a 3000-foot-long (914.3 m) headrace tunnel for maximizing the development of the available head as suggested by EBA in its 1994 study. Figure 18 shows the general location of the Pumphouse Dam site with the largest features and associated features the tunnel and powerhouse
sites. Figure 19 shows more specific site plans of the Option 3 RCC dam and the alternative location of the arch dam site.

When updating the cost estimate for developing the Project, we tried to consider the effects of recent dramatic cost escalations that would not have been entirely captured through the use of the USBR cost trend escalation factors. A report by the Brattle Group dated September 2007, titled “Rising Utility Construction Costs – Sources and Impacts” states that between January 2004 and January 2007, the costs of steam-generating plant and transmission projects, the cost of equipment has risen between 25% and 35%, which can be extended to recent bidding of hydro turbine-generating equipment, with which we are familiar. The reason for such cost escalation to equipment fabrication and civil works construction are due to the following: 1) rising material costs, such as steel and cement; 2) shop and fabrication capacity; 3) rising cost of construction field labour; and 4) the currently high market for large construction projects, i.e., the queuing and bidding for such projects.

With such recent construction escalation of pricing to both equipment procurement and civil works construction, we’ve placed increased emphasis on further increasing such cost increases in our cost update.

3.4.2.1.2 Geology and Geotechnical Conditions

An earlier geology study of the study area (V. Preto 1972) indicates that bedrock is extremely variable in nature, ranging from very sound and competent, recent intrusions rocks, to weathered and poorly indurated volcanic rocks and relatively old sedimentary rocks. Stewart-EBA state in its 1992 pre-feasibility study that there do not appear to be any geology conditions adverse to the development of the proposed dams.

Following glaciation, erosion has removed most evidence of glaciation within the Similkameen River canyon. Mos: overburden deposits now present within the canyon consists of alluvial sand and/or gravel deposits and talus deposits of weathered rock debris.

EBA state in its 1994 study that the rock outcrops exposed at the proposed Pumphouse dam site are prominent and appear to be considerably more competent than in other areas of the canyon. While there have been many faults identified in the area, none of the known discontinuities extend under the dam site.

3.4.2.1.3 Dam Cost

3.4.2.1.3.1 RCC Dam Type

The cost review was based on the premise that RCC was a suitable dam type for the site and that the seismic and flood design criteria, which as yet has adequately been established, would not have an appreciable effect on dam cost.

The 1994 EBA study revised its dam type recommendation from a concrete-faced rockfill structure to a roller compacted concrete (RCC) structure. Both of these options are preference over other types of dams due to the lack of clay and site for an impermeable material source. An analysis of mining waste rock indicated that the rock was not acidic.
The RCC dam would involve importing fly ash and cement to the site and processing waste rock from nearby mining operations for use as coarse aggregate and tailings for fine aggregate. The use of waste rock and tailings could help reduce the cost of RCC construction by eliminating the need to establish a quarry for concrete aggregate material source.

A limited program of geochemical testing was previously carried out (Stewart-EBA, 1990) to identify whether the use of waste rock or tailings for dam construction could cause acid rock drainage, which could pose a problem in the use of such material. Acid rock drainage can occur when rock containing mineralization with various sulphur compounds is exposed to conditions which liberate the sulphur as an acid solution. Test results indicate that there is more than sufficient neutralization potential to offset the acid generating potential, particularly for waste rock from Pit No. 3.

The EBA study assumed an average excavation to sound rock foundation of approximately 15 feet (4.5 m), which appears to be reasonable given the description of the geology at the site.

The dam crest elevation was based on a 100-foot-wide (30.5 m) ungated spillway capable of passing the 100-year-return-period flood. Based on this assumption, the height of the dam would be about 15 feet (4.5 m) above normal maximum reservoir elevation. However, the dams are high structures and, per Canadian Dam Association Dam Safety Guidelines, would be classified as very high consequence category, and the spillway structure would need to be designed to pass the probable maximum flood (PMF). Therefore the proposed dam would need to be taller than assumed by EBA. If the development of the dam is to be pursued, we recommend that a PMF study be performed to derive the flood, which will need to be passed through the spillway structure without overtopping the dam crest. For the purpose of our review, we assumed that the PMF would be 3 times the flood of record (May 1972 flood), or approximately 1,400 m$^3$/sec (49434 cfs). We also assumed that passing the flood over the top of the dam crest with a 300 (91.5 m) to 600-foot (183 m) descent may not be a suitable design approach for a number of reasons. Accordingly, we assumed a separate spillway structure that would be located on either abutment, but that the spillway would be comprised of a 500-foot-long (152.4 m) side channel spillway with a chute width of about 50 feet (15.2 m). The spillway crest would need to be about 10 feet above normal maximum pool level. Separating the spillway from the RCC structure would further simplify the construction of the RCC dam.

The dam assumed that the downstream slope would be 0.70 vertical to 1.0 horizontal and that the upstream slope would be vertical. The crest width was assumed to be 20 feet (6.0 m), although the upper 20 feet (6.0 m), of the dam height maintained this 20-foot (6.0 m), thickness before sloping downward at the 0.7:1.0 slope. The design appears typical of many similar dam sections assuming that the seismic conditions are of low intensity at the site.

In our review of the EBA estimate of RCC volume needed for dam construction, we used an empirical formula that relates dam slope, dam length, crest width and other shaping characteristics of the dam. From this review, we concluded that the 1,760,000 cubic yards of RCC quantity estimated is low. Our quantity estimate indicates that the dam volume would be higher, or approximately 2,230,000 cubic yards.
Based on the volume of the concrete in the RCC dam, we calculated the unit price of RCC based on another empirical formula. For an RCC dam constructed in North America with similar volume as the Project, the average unit price, inclusive of facing concrete, would on January 2008, be estimated to be about $44 per cubic yards (cy). When relating the cost of the RCC placement to that of the entire dam, which would include the cost of concrete and RCC, dam excavation, foundation work, the spillway and outlet works, a factor of 1.5 was assumed to be multiplied to the RCC cost component. For the two smaller RCC dam sizes (470 (143.2 m) and 345-ft-high structures (105.1 m), we estimated the concrete volumes to be 1,150,000 CY and 470,000 CY, respectively. Then, we assumed corresponding cost adjustment multipliers of 1.7 and 1.9.

The total cost estimate for the RCC dam structures would not include the cost of river diversion, access to site, land acquisition, environmental mitigation or recreation facilities.

3.4.2.1.3.2 Arch Dam Type

From our review of the topography about 300 feet (91.4 m) upstream of the Pumphouse dam site of the EBA study, we identified a site with good topographic characteristics for an arch dam (see Figure 19). The crest width to dam height ratio is less than 1.4 for a 240-foot (73.1 m) high dam, which is a very good indicator for a low-cost concrete arch dam site, assuming good rock conditions exist. We then added another 30-feet (9.1 m) to this height; although the abutments would include a more conventional concrete gravity section, with the right abutment including gated spillway structures.

Similar to the RCC dam calculation of concrete volume and unit pricing, we used empirical formulas for estimating the cost estimate of two alternative dam sizes at the site. Both alternatives would be significantly smaller than for the RCC site.

3.4.2.1.4 Diversion Tunnel

In the pre-feasibility study, the diversion tunnel was assumed to be 20-feet (6.0 m) in diameter. We used this diameter in our estimate. The length of the tunnel was measured on the drawing to be 1,200 feet (365.7 m); however, we reduced this length to 1,000 feet (304.8 m) to account for expected portal excavation. We used in-house cost curves for estimating excavation costs. We assumed only modest rock supports (15% of excavation costs). We assumed that 150 feet (45.7 m) of tunnel at each portion would need to be lined with concrete.

For the arch dam alternatives, we assumed the diversion tunnel to be of a shorter length.

For the cofferdams and other assumption, we increased that portion of the EBA cost estimate by USBR cost trends for the 17 Western States to account for price escalation between today and January 1994.

3.4.2.1.5 Penstock

3.4.2.1.5.1 Surface Penstock

The feasibility study stated that the penstock was comprised of a short tunnel; however, we assumed that the penstock would be trenched and that a steel pressure vessel would be encased in concrete. We estimated that economic diameter of the penstock to be approximately 11.5 feet (3.5 m). Our
estimate of steel for the pipe, based on expected transient pressure, was considerably higher than estimated by the study engineer. With our estimate of civil work quantities, we applied unit pricing based on our experience with similar projects in North America.

3.4.2.1.5.2 Headrace Tunnel

The topographical information indicates that a 3,000-foot-long (914.4 m) tunnel can develop an additional 80 feet (24.4 m) of gross head for hydro power. The analysis of this modification could improve the overall economics of the project; however, such a feature would probably required a small hydro unit at the foot of the dam for ecological flows needed in the bypass channel that extends over the distance of the headrace tunnel between the dam and main powerhouse structure.

For the headrace tunnel, we assumed a 13-foot-diameter (3.9 m) horseshoe-shaped, concrete-lined tunnel that would be conventionally driven from a downstream portal location up on the hillside to maintain a relatively low pressure. A high-pressure surface penstock comprised of steel pipe would then descend to the powerhouse structure at river level. Moderate amount of supports were assumed, with steel sets for about 100 feet (30.5 m) at each portal location, then rock bolts and shotcrete as required for the balance of the distance.

3.4.2.1.6 Powerhouse

The powerhouse locations were generally near the foot of the dam and were assumed to be a surface structure that would house three Francis turbine units. The sizes of the units are such that the Francis units would likely be horizontal rather than vertical units, which would help to reduce slightly the cost of the powerhouse structure.

The feasibility study didn't provide any details of its powerhouse cost estimate. Therefore, we used empirical formulas for estimating the costs for the turbine, generator and turbine inlet valves. The cost formula uses the following parameters: design head, unit speed and installed capacity. Cost coefficient for this equation was taken from somewhat recent purchased Francis turbine-generator equipment for similar powerhouse design. We then further escalated the turbine-generator equipment costs by 20% to account for recent increases in equipment pricing that may not have been captured from USBR cost trend indices. Other elements of the project costs such as miscellaneous power house equipment, accessory electrical equipment and the powerhouse civil structure were derived as a percentage of turbine-generator equipment cost as based on the plant installed capacity and unit speed. Such estimating methodology is similar to U.S. Bureau of Reclamation cost estimating guide for hydroelectric power plants. Other mechanical features, such as bridge cranes and draft tube gates were estimated separately.

3.4.2.1.7 Transmission Line and Substation Cost

The BC Hydro 138 kV transmission line runs directly passed the proposed powerhouse site. This line is interconnected with the West Kootenay Power and Princeton Light & Power systems at Princeton.

Because the cost of interconnecting the project to the BCTC transmission system is expected to be low, this feature was not reviewed. We simply escalated its previous cost estimate by the USBR cost trends for the 17 Western States to account for price escalation between today and January 1994. If
the project is to be further developed, we recommend that load flow studies be performed to ensure that the existing transmission line can receive additional capacity.

3.4.2.1.8 Direct Construction Cost
The direct construction cost (DCC) includes the total of all costs directly chargeable to a specific project including land, relocations, and environmental mitigation, and construction and equipment contracts. As mentioned, our estimate of DCC does not include land acquisition or environmental mitigation measures.

The estimated costs of the items included in the DCC for the construction elements of project components were based on conceptual layouts and preliminary dimensions of the various facility features. As applicable, the estimates as presented identify the bid quantities of construction and apply unit prices to these quantities to obtain estimated construction costs at a January 2008 bid price level.

3.4.2.1.9 Total Construction Cost
The total construction cost (TCC) includes the direct construction cost plus contingencies, engineering and owner administrative costs. Such costs are often expressed as a percentage of the DCC and were reviewed on this basis as shown below. The total construction costs estimated herein assume built-in escalation during the construction period.

3.4.2.1.10 Engineering
The approximate Engineering and Owner Administration budget that we assume would be needed for a project of this scope were assumed to be on a sliding scale as shown in Table 10.

<table>
<thead>
<tr>
<th>Table 10</th>
<th>Engineering Cost Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Item</td>
<td>Option 1 (35 MW)</td>
</tr>
<tr>
<td>Engineering Design</td>
<td>8.0%</td>
</tr>
<tr>
<td>Construction Management</td>
<td>4.5%</td>
</tr>
<tr>
<td>Owner Administration</td>
<td>2.5%</td>
</tr>
<tr>
<td>Total</td>
<td>15.0%</td>
</tr>
</tbody>
</table>

Engineering Design would include feasibility investigations, environmental studies and project licensing.

3.4.2.1.11 Contingencies
The use of contingencies provides for those unexpected or unknown costs that may develop. For reconnaissance level investigations, where there is an absence of subsurface investigations, it is normal practice to assume a 25% contingency on the DCC and engineering. Such an assumption was stated as appropriate for the 1992 pre-feasibility study although it wasn’t included in its cost estimate. The rationale was that too high of a contingency level may prematurely eliminate a
potentially viable hydro project from further consideration; it was better to first perform additional investigations to better establish project development costs.

In our evaluation of costs, we assumed contingencies to be 25% of the DCC plus engineering contingencies.

The study indicated that the mining activity in the vicinity of the dam has an abundance of subsurface information; however, we have not seen any of it in order to determine whether contingencies should be higher or lower. In general, specific site information is needed before any confidence in dam, tunnel, and powerhouse structure construction costs can be assessed. Similarly, we find that before any contractor bidding takes place, a comprehensive subsurface investigation is needed; otherwise civil works construction costs will invariably escalate as site conditions change from those that were assumed.

3.4.2.1.12 Total Investment Cost

The total investment cost is the sum of the total construction cost plus IDC. Interest during construction (IDC) was estimated from a typical cash flow formula for hydro development. We assumed 2 to 2½ years construction of the project. The interest rate of short-term financing was assumed to be the same as long term financing. Table 11 presents a summary of the total investment cost for each of the alternatives. The previous studies did not include GST in their cost estimate; presumably because hydroelectric projects are considered to be renewable energy projects receive tax breaks on development.

<table>
<thead>
<tr>
<th>Item</th>
<th>Option 1 (35 MW)</th>
<th>Option 2 (50 MW)</th>
<th>Option 3 (60 MW)</th>
<th>Option 3 w/ Tunnel</th>
<th>Arch Dam (25 MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mobilization</td>
<td>$3,300,000</td>
<td>$5,700,000</td>
<td>$8,300,000</td>
<td>$9,000,000</td>
<td>$1,800,000</td>
</tr>
<tr>
<td>Dam and Spillway</td>
<td>55,000,000</td>
<td>102,700,000</td>
<td>152,900,000</td>
<td>152,900,000</td>
<td>27,600,000</td>
</tr>
<tr>
<td>Intake and Penstock</td>
<td>3,510,000</td>
<td>3,970,000</td>
<td>4,730,000</td>
<td>$17,030,000</td>
<td>1,990,000</td>
</tr>
<tr>
<td>powerhouse</td>
<td>23,500,000</td>
<td>27,670,000</td>
<td>29,680,000</td>
<td>$33,050,000</td>
<td>19,190,000</td>
</tr>
<tr>
<td>Substation &amp; Transmission</td>
<td>3,620,000</td>
<td>3,620,000</td>
<td>3,620,000</td>
<td>$3,990,000</td>
<td>3,620,000</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>$88,930,000</strong></td>
<td><strong>$143,660,000</strong></td>
<td><strong>$199,230,000</strong></td>
<td><strong>$215,970,000</strong></td>
<td><strong>$54,200,000</strong></td>
</tr>
<tr>
<td>Contingencies</td>
<td>22,200,000</td>
<td>35,900,000</td>
<td>49,800,000</td>
<td>54,000,000</td>
<td>13,600,000</td>
</tr>
<tr>
<td>Engineering</td>
<td>16,700,000</td>
<td>22,400,000</td>
<td>24,900,000</td>
<td>27,000,000</td>
<td>10,200,000</td>
</tr>
<tr>
<td><strong>Total Construction Cost</strong></td>
<td><strong>$127,830,000</strong></td>
<td><strong>$201,960,000</strong></td>
<td><strong>$273,930,000</strong></td>
<td><strong>$296,970,000</strong></td>
<td><strong>$78,000,000</strong></td>
</tr>
<tr>
<td>Interest During Construction</td>
<td>8,400,000</td>
<td>13,300,000</td>
<td>22,600,000</td>
<td>24,500,000</td>
<td>6,400,000</td>
</tr>
<tr>
<td><strong>Total Investment Cost</strong></td>
<td><strong>$136,230,000</strong></td>
<td><strong>$215,260,000</strong></td>
<td><strong>$296,530,000</strong></td>
<td><strong>$321,470,000</strong></td>
<td><strong>$84,400,000</strong></td>
</tr>
</tbody>
</table>
3.4.2.2 Energy Estimates

Monthly average energy estimates for the different alternatives is summarized in Table 12. It should be noted that most of the energy produced from any of the alternatives is during the freshet months of May through July. If a project has a large storage reservoir (e.g., Option 3), then generation increases during the other months as the storage is depleted to minimum pool at the start of the following freshet period.

Table 12 Summary of Available Energy Estimates (GWh)

<table>
<thead>
<tr>
<th>Month</th>
<th>Option 1 35 MW</th>
<th>Option 2 50 MW</th>
<th>Option 3 60 MW</th>
<th>Option 3 w/Tunnel</th>
<th>Arch 25 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>2.5</td>
<td>4.9</td>
<td>19.7</td>
<td>20.3</td>
<td>2.7</td>
</tr>
<tr>
<td>Feb</td>
<td>1.9</td>
<td>3.5</td>
<td>14.0</td>
<td>14.5</td>
<td>2.1</td>
</tr>
<tr>
<td>Mar</td>
<td>2.4</td>
<td>3.9</td>
<td>8.3</td>
<td>9.0</td>
<td>3.1</td>
</tr>
<tr>
<td>Apr</td>
<td>6.0</td>
<td>9.5</td>
<td>12.9</td>
<td>14.9</td>
<td>7.5</td>
</tr>
<tr>
<td>May</td>
<td>19.9</td>
<td>26.2</td>
<td>28.6</td>
<td>33.5</td>
<td>18.5</td>
</tr>
<tr>
<td>Jun</td>
<td>24.2</td>
<td>34.2</td>
<td>37.4</td>
<td>42.7</td>
<td>17.9</td>
</tr>
<tr>
<td>Jul</td>
<td>16.4</td>
<td>22.7</td>
<td>27.0</td>
<td>32.5</td>
<td>15.4</td>
</tr>
<tr>
<td>Aug</td>
<td>9.2</td>
<td>13.8</td>
<td>19.5</td>
<td>24.4</td>
<td>4.1</td>
</tr>
<tr>
<td>Sept</td>
<td>5.1</td>
<td>12.3</td>
<td>17.9</td>
<td>21.1</td>
<td>2.2</td>
</tr>
<tr>
<td>Oct</td>
<td>2.9</td>
<td>11.9</td>
<td>16.1</td>
<td>17.4</td>
<td>2.4</td>
</tr>
<tr>
<td>Nov</td>
<td>3.4</td>
<td>9.3</td>
<td>16.9</td>
<td>17.7</td>
<td>3.4</td>
</tr>
<tr>
<td>Dec</td>
<td>3.3</td>
<td>6.0</td>
<td>15.6</td>
<td>16.3</td>
<td>3.0</td>
</tr>
<tr>
<td>Mean</td>
<td>97.2</td>
<td>158.2</td>
<td>233.9</td>
<td>264.3</td>
<td>82.3</td>
</tr>
</tbody>
</table>

The generation estimates for Options 1 through 3, were previously estimated in the 1994 PP&L study by Acres International (now Hatch Ltd.) using a reservoir operational model, which is still available for use in further optimization of project installed capacity and storage size. The model accounted for reservoir evaporation losses, assumed head losses through the penstock were 2% of gross head, and an average plant efficiency of 89%. This average efficiency is consistent with the plant operating at near best gate operation for most of the time due to the reservoir providing extensive flow regulation capability. Three different installed capacities were evaluated for each of the three storage options with the largest installed capacity summarized in Table 12. Design head is generally established at about 1/3rd of maximum drawdown from normal maximum pool. The energy estimates for the Arch dam alternative, were based on a monthly-average spreadsheet model, which provides an initial approximation of energy generation. We did not assume that storage would be used with the possible exception of daily peaking operation, if such an operation were permitted.
The turbine guidelines presented by the USBR indicate limits to maximum and minimum turbine heads of 125% and 65% of rated head, which equates to a minimum head of (65/125) equal to 52% of maximum head. However, such a reservoir level fluctuation may not be desirable for a number of reasons, including lower head, less turbine unit efficiency and rough turbine operation. At the minimum extreme head, power drops off in proportion to $H^{1.5}$ (where $H$ equals net head); therefore, the maximum power at minimum head would only be about 37% of power at rated head. Efficiency would likely drop about 15%, and the unit will tend to run rougher.

The storage for the three different dam sites was predicated on drafting reservoir from normal maximum pool level by 120 feet (37.5 m). Therefore, the smaller reservoirs would have larger percentage swing of net head from maximum head – up to approximately 38%, as oppose to the largest reservoir, which would only have a maximum head swing of about 21%. From this cursory review, it appears that the largest reservoir certainly could have used more of its storage potential for increasing project generation. With the addition of the tunnel, the argument of increasing available storage becomes even more profound. If a Similkameen reservoir storage project is to be further investigated for possible develop, we recommend further optimization investigation of reservoir size for maximizing energy production.

3.4.2.3 Reservoir Storage

3.4.2.3.1 General

From previous studies, it was suggested that the need for additional storage in the basin could ultimately be on the order of 80,000 acre-feet (98.68 Mm$^3$), based on maximum water demands from mining, industry, irrigation and hydroelectric. Such storage requirements could be provided by Options 2 and 3; although, this would necessitate a different operational regime of these options that might reduce the hydroelectric potential of these options.

The use of storage as assumed by the power operational models for each of the alternatives investigated made use of a reservoir “rule curve” as shown in Table 13. The model makes decisions on whether a plant can generate more or less based on the reservoir level and the amount of river inflow. If the reservoir level is below the rule curve, the plant is told to shut down and no outflow releases are made; therefore, there would never be an instance when the reservoir falls much below the rule curve, unless the curve is rising and there is not much inflow. Such a scenario could occur during a late freshet period.

Table 13  Rule Curve – End of Month Elevation (m)

<table>
<thead>
<tr>
<th>Month</th>
<th>Option 1</th>
<th></th>
<th>Option 2</th>
<th></th>
<th>Option 3</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>m</td>
<td>ft</td>
<td>m</td>
<td>ft</td>
<td>m</td>
<td>ft</td>
</tr>
<tr>
<td>Jan</td>
<td>825.80</td>
<td>2709.45</td>
<td>863.90</td>
<td>2834.46</td>
<td>902.00</td>
<td>2959.46</td>
</tr>
<tr>
<td>Feb</td>
<td>820.80</td>
<td>2693.04</td>
<td>858.90</td>
<td>2818.05</td>
<td>897.00</td>
<td>2943.06</td>
</tr>
<tr>
<td>Mar</td>
<td>816.86</td>
<td>2680.12</td>
<td>854.96</td>
<td>2805.12</td>
<td>893.06</td>
<td>2930.13</td>
</tr>
<tr>
<td>Apr</td>
<td>816.86</td>
<td>2680.12</td>
<td>854.96</td>
<td>2805.12</td>
<td>893.06</td>
<td>2930.13</td>
</tr>
<tr>
<td>Month</td>
<td>Option 1</td>
<td>Option 2</td>
<td>Option 3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>-------</td>
<td>----------</td>
<td>----------</td>
<td>----------</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>m</td>
<td>ft</td>
<td>m</td>
<td>ft</td>
<td>m</td>
<td>ft</td>
</tr>
<tr>
<td>May</td>
<td>830.80</td>
<td>2725.85</td>
<td>868.90</td>
<td>2850.86</td>
<td>907.00</td>
<td>2975.87</td>
</tr>
<tr>
<td>Jun</td>
<td>853.44</td>
<td>2800.14</td>
<td>891.54</td>
<td>2925.14</td>
<td>929.64</td>
<td>3050.15</td>
</tr>
<tr>
<td>Jul</td>
<td>853.44</td>
<td>2800.14</td>
<td>891.54</td>
<td>2925.14</td>
<td>929.64</td>
<td>3050.15</td>
</tr>
<tr>
<td>Aug</td>
<td>849.80</td>
<td>2788.19</td>
<td>887.90</td>
<td>2913.20</td>
<td>926.00</td>
<td>3038.21</td>
</tr>
<tr>
<td>Sep</td>
<td>845.30</td>
<td>2773.43</td>
<td>883.40</td>
<td>2898.44</td>
<td>921.50</td>
<td>3023.44</td>
</tr>
<tr>
<td>Oct</td>
<td>842.30</td>
<td>2763.59</td>
<td>880.40</td>
<td>2888.59</td>
<td>918.50</td>
<td>3013.6C</td>
</tr>
<tr>
<td>Nov</td>
<td>838.30</td>
<td>2750.46</td>
<td>876.40</td>
<td>2875.47</td>
<td>914.50</td>
<td>3000.47</td>
</tr>
<tr>
<td>Dec</td>
<td>842.30</td>
<td>2763.59</td>
<td>880.40</td>
<td>2888.59</td>
<td>918.50</td>
<td>3013.6C</td>
</tr>
</tbody>
</table>

Based on the modeling performed by Acres International (EBA 1994), the reservoir level was assumed to be at minimum pool at the beginning of the freshet period on April 30th with maximum pool level, provided that sufficient flow volume has occurred, on June 30th. Over the ensuing 2½ month irrigation period, when water availability deficits generally occur from July 1st through September 15th, these reservoirs were only forecasted to use only a modest amount of storage. In fact, during July no storage from the project reservoir was assumed to be used to augment possible low flows, principally because July was viewed as a relatively high-flow month as river flows were still benefiting from snowmelt in the upper watershed.

### 3.4.2.3.2 Flood Control Benefits

The 1972 spring flood, which was estimated to exceed the 200-year frequency event, caused a number of damages to the Similkameen Basin. Bridges on a number of creeks were washed out (Similkameen Spotlight; Jan 16, 1991). Sixty families within the town of Princeton were moved from their homes. Flooded basements in lower areas were common. In Hedley, bridges carrying water lines were washed out and the town was without water. Homes washed downstream as 20 Mile (32.2 km) Creek changed course. A dike gave way in Keremeos, and flood waters rushed into town.

If the project included the largest dam size, e.g. 600-ft-high (188 m), then some incidental flood control benefits would result in reducing flood damages. As the river includes a levee system for flood protection up to the 200-year flood, the spring flood of 1972 would be of particular interest to analyze to assess how the flood levels may have been reduced if a large Similkameen Storage Dam were in-place. The 1972 spring flood peaked in the upper Similkameen Basin on about May 31st with a maximum daily-average discharge of 472 m³/sec (16,671 cfs). The flood levels remained high and peaked again on about June 10th with a peak discharge of about 420 m³/sec (14,834 cfs). It would appear that the reservoir storage levels for any of the options, unless there was a low-level flood-release cutlet, would be at normal maximum pool level and thereby provide only incidental flood benefits based on the available storage above the spill crest.
A hydrology study for the Similkameen Hydroelectric Project prepared by PWS Engineering in November 1992, assessed the storage capability of the 600-ft (188 m) high dam in the upper basin and concluded that some modest improvements would result. The project included spill gates that would be used to limit reservoir outflow to approximately 300 m³/sec (10,596 cfs). They estimated that for the spring 1972 flood, the project would have reduced the peak daily discharge by 121 m³/sec (4,273 cfs) from the recorded peak of 929 m³/sec (32,812 cfs). Modeling was based on the use of the COE HEC-5 reservoir operation computer modeling program.

More detailed modeling would need to take place for any final conclusion, but it would appear that for the smaller sized reservoir options, little benefit for flood control would occur.

Frazil Ice: In turbulent streams the first ice to form is frazil ice, which are small crystals suspendec in the turbulent flow. In river reaches where turbulence is not sufficient to keep the frazil ice mixec in the stream, the ice rises to the surface to form a sheet of ice. If there are obstructions within the river, such as bridges or reservoirs, there could be a large accumulation of frazil ice, which causes undesirable channel restrictions and back water. Frazil ice is a current common occurrence within the Similkameen River, which creates ice jams that reduces the carrying capacity of the river channel and increases the instances of overtopping of flood control levees. An editorial in the Similkameen Spotlight, dated January 9, 1991 addressed ice jam and flooding issues. On January 19, 2005, an ice jam in the Similkameen caused flooding of parts of the valley and forced the evacuation of 200 people from their homes.

The PWS Engineering Study (1992) states that reservoir releases at a Copper Mountain Dam site could create a condition favourable to the generation of frazil ice. Higher than normal water temperatures released through the hydro plant could delay ice cover formation and thus increase the opportunity for frazil ice formation.
3.4.2.3.3 Low Flow Augmentation

Modeling work was performed to illustrate the effect of the 600-ft (183 m) dam storage project on minimum flow releases at different gauging locations.

From a water quality perspective, Table 14 illustrates possible improvement of water quality in August through February from increased flows in the Similkameen River below the dam site of a large storage reservoir. Improvement could have extended into March and April if it were not for the adopted rule curves which left little carry over storage for these two months. For the smaller reservoirs, flow augmentation would be considerably less. More detailed modeling is needed in order to better assess potential improvement to water quality.

The water temperature in the Similkameen River can be affected by dam discharge temperature down to approximately 3 miles (5 kilometers) below the town of Hedley. During the winter months, the reservoir water would be warmer than the river water temperatures, and during the summer months, reservoir water temperature could be cooler or warmer than river water temperatures depending on the depth of water to the power intake.

3.4.2.3.4 Water Supply

Of the storage options, the large 600-ft. high (183 m) dam may only provide the best opportunity for meeting the water supply requirements within the basin. While the PP&L proposed operation does not show any benefit in July, this is due to the assumptions applied to the reservoir operation model rather than what the project could actually deliver in terms of carry over water in potentially critical irrigation months of July through September 15th.

3.4.2.4 Economic Analysis

Annual costs of the power project would be apportioned into fixed and variable costs. For this analysis, the fixed amount, amortization of the Total Capital Requirements less earnings on Reserves, is based on 6% interest rate financing over an assumed 30-year term and service life. Variable annual costs escalate each year and include operation and maintenance (O&M) costs, administrative and general expenses, interim replacements and insurance. The basic assumptions for determining the annual fixed and variable costs of the power project are shown in Table 15. The development of the annual cost as well as the resulting unit cost of power for each of the alternative development schemes considered herein are shown in 2008 dollars in Tables 16 and 17.

Per the Water Resource Protection Act (Bill M 215 – 2007), water-use royalty charges will be paid to the B.C. provincial government as fixed to a percentage of the average market price of power. For other recent facilities with which we are familiar this rate is based on the product of the Facility installed capacity and a cost rate of $3,620/MW plus the product of the Facility energy production and a cost rate of $1.086/MWh for the initial generation of 160 GWh from each hydrop plant and $5.069/MWh for any additional generation. Power generated by BC Hydro and Columbia Power would be exempted from such royalty fees. Other expenses for project development would include right of way costs, which were not included in the analysis.
### Table 14: Comparison of Streamflow at the Princeton Gauge with and without Flow Regulation from 600 ft (183 m) High Dam

<table>
<thead>
<tr>
<th>Month</th>
<th>Unregulated</th>
<th></th>
<th></th>
<th>Regulated</th>
<th></th>
<th></th>
<th>Amount change</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min</td>
<td>Mean</td>
<td>Min</td>
<td>Mean</td>
<td>Min</td>
<td>Mean</td>
<td>Min</td>
<td>Mean</td>
<td></td>
</tr>
<tr>
<td></td>
<td>m³/s</td>
<td>cfs</td>
<td>m³/s</td>
<td>cfs</td>
<td>m³/s</td>
<td>cfs</td>
<td>m³/s</td>
<td>cfs</td>
<td></td>
</tr>
<tr>
<td>Jan</td>
<td>1.65</td>
<td>58.3</td>
<td>5.90</td>
<td>208.4</td>
<td>8.18</td>
<td>288.9</td>
<td>15.35</td>
<td>542.2</td>
<td></td>
</tr>
<tr>
<td>Feb</td>
<td>2.11</td>
<td>74.5</td>
<td>5.18</td>
<td>183.0</td>
<td>7.47</td>
<td>263.8</td>
<td>16.64</td>
<td>587.7</td>
<td></td>
</tr>
<tr>
<td>Mar</td>
<td>2.82</td>
<td>99.6</td>
<td>6.85</td>
<td>241.9</td>
<td>2.82</td>
<td>99.6</td>
<td>10.52</td>
<td>371.6</td>
<td></td>
</tr>
<tr>
<td>Apr</td>
<td>4.34</td>
<td>153.3</td>
<td>16.96</td>
<td>599.0</td>
<td>4.34</td>
<td>153.3</td>
<td>17.01</td>
<td>600.8</td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>29.60</td>
<td>1045.5</td>
<td>78.45</td>
<td>2770.8</td>
<td>24.88</td>
<td>878.8</td>
<td>39.73</td>
<td>1403.3</td>
<td></td>
</tr>
<tr>
<td>Jun</td>
<td>43.10</td>
<td>1522.3</td>
<td>97.95</td>
<td>3459.6</td>
<td>9.21</td>
<td>325.3</td>
<td>72.36</td>
<td>2555.7</td>
<td></td>
</tr>
<tr>
<td>Jul</td>
<td>8.50</td>
<td>300.2</td>
<td>33.79</td>
<td>1193.5</td>
<td>7.69</td>
<td>271.6</td>
<td>33.47</td>
<td>1182.2</td>
<td></td>
</tr>
<tr>
<td>Aug</td>
<td>3.82</td>
<td>134.9</td>
<td>8.94</td>
<td>315.8</td>
<td>7.52</td>
<td>265.6</td>
<td>12.68</td>
<td>454.2</td>
<td></td>
</tr>
<tr>
<td>Sep</td>
<td>2.75</td>
<td>97.1</td>
<td>5.00</td>
<td>176.6</td>
<td>7.58</td>
<td>267.7</td>
<td>17.71</td>
<td>625.5</td>
<td></td>
</tr>
<tr>
<td>Oct</td>
<td>2.37</td>
<td>83.7</td>
<td>5.24</td>
<td>185.1</td>
<td>7.56</td>
<td>267.0</td>
<td>14.45</td>
<td>510.4</td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>2.29</td>
<td>80.9</td>
<td>7.79</td>
<td>275.1</td>
<td>7.72</td>
<td>272.7</td>
<td>13.13</td>
<td>463.7</td>
<td></td>
</tr>
<tr>
<td>Dec</td>
<td>1.98</td>
<td>69.9</td>
<td>6.50</td>
<td>229.6</td>
<td>7.92</td>
<td>279.7</td>
<td>15.41</td>
<td>544.3</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Min</th>
<th>Mean</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>m³/s</td>
<td>cfs</td>
</tr>
<tr>
<td></td>
<td>6.53</td>
<td>230.6</td>
</tr>
<tr>
<td></td>
<td>5.36</td>
<td>189.3</td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>-4.72</td>
<td>-166.7</td>
</tr>
<tr>
<td></td>
<td>-33.89</td>
<td>-1197.0</td>
</tr>
<tr>
<td></td>
<td>-0.81</td>
<td>-28.6</td>
</tr>
<tr>
<td></td>
<td>3.70</td>
<td>130.7</td>
</tr>
<tr>
<td></td>
<td>4.83</td>
<td>170.6</td>
</tr>
<tr>
<td></td>
<td>5.19</td>
<td>183.3</td>
</tr>
<tr>
<td></td>
<td>5.43</td>
<td>191.8</td>
</tr>
<tr>
<td></td>
<td>5.94</td>
<td>209.8</td>
</tr>
</tbody>
</table>

Note: The amount change is calculated as the difference between the regulated and unregulated values.
Table 15  Basic Assumptions for Economic Analyses

<table>
<thead>
<tr>
<th>Item</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Period</td>
<td>24 to 30 months</td>
</tr>
<tr>
<td>Financing Term</td>
<td>30 years</td>
</tr>
<tr>
<td>Financing Interest Rates</td>
<td>6%</td>
</tr>
<tr>
<td>Reinvestment Rate</td>
<td>Same as interest rate</td>
</tr>
<tr>
<td>Financing Reserve</td>
<td>1/2 year of debt service</td>
</tr>
<tr>
<td>Financing Expenses</td>
<td>3% of Total Investment Cost</td>
</tr>
<tr>
<td>O&amp;M Cost</td>
<td>$10/kW plus 0.1% of Dam Cost</td>
</tr>
<tr>
<td>Administration &amp; General</td>
<td>40% of O&amp;M</td>
</tr>
<tr>
<td>Insurance</td>
<td>0.1% of TIC</td>
</tr>
<tr>
<td>Renewal and Replacement</td>
<td>$4/kW plus 0.05% of Dam Cost</td>
</tr>
</tbody>
</table>

Table 16  Summary of Total Capital Requirements of Pumphouse Hydro Alternatives (2008 Price Level)

<table>
<thead>
<tr>
<th>Item</th>
<th>Option 1 (35 MW)</th>
<th>Option 2 (50 MW)</th>
<th>Option 3 (60 MW)</th>
<th>Option 3 w/ Tunnel</th>
<th>Arch Dam (25 MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Investment Cost</td>
<td>$136,230,000</td>
<td>$215,260,000</td>
<td>$296,530,000</td>
<td>$321,470,000</td>
<td>$84,400,000</td>
</tr>
<tr>
<td>Reserve Account</td>
<td>5,300,000</td>
<td>8,330,000</td>
<td>11,415,000</td>
<td>12,375,000</td>
<td>3,285,000</td>
</tr>
<tr>
<td>Cost of Issuance</td>
<td>4,380,000</td>
<td>5,730,000</td>
<td>6,280,000</td>
<td>6,810,000</td>
<td>2,710,000</td>
</tr>
<tr>
<td>Gross Financing Requirement</td>
<td>$145,910,000</td>
<td>$229,320,000</td>
<td>$314,225,000</td>
<td>$340,655,000</td>
<td>$90,395,000</td>
</tr>
<tr>
<td>Cost per kW</td>
<td>$4,170</td>
<td>$4,590</td>
<td>$5,240</td>
<td>$4,980</td>
<td>$3,620</td>
</tr>
</tbody>
</table>

Table 16 indicates a high cost of development for the EBA study Options 1 through 3, which include large roller compacted concrete (RCC) structures. Alternative concrete arch dams may provide improved economics for power development; however, the lack of storage with these smaller structures may not provide much in other water resource benefits, e.g. flood control, water supply, improved water quality.
Table 17  Estimated Annual Cost of Power for Pumphouse Hydro Alternatives (2008 Price Level)

<table>
<thead>
<tr>
<th>Item</th>
<th>Option 1 (35 MW)</th>
<th>Option 2 (50 MW)</th>
<th>Option 3 (60 MW)</th>
<th>Option 3 w/ Tunnel</th>
<th>Arch Dam (25 MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Debt Service</td>
<td>$10,600,000</td>
<td>$16,660,000</td>
<td>$22,830,000</td>
<td>$24,750,000</td>
<td>$6,570,000</td>
</tr>
<tr>
<td>less Interest Credit on Reserve</td>
<td>-320,000</td>
<td>-500,000</td>
<td>-680,000</td>
<td>-740,000</td>
<td>-200,000</td>
</tr>
<tr>
<td>Net Amortization Costs</td>
<td>$10,280,000</td>
<td>$16,160,000</td>
<td>$22,150,000</td>
<td>$24,010,000</td>
<td>$6,370,000</td>
</tr>
</tbody>
</table>

**Operating Costs:**

- Operation and Maintenance: 405,000 603,000 753,000 753,000 278,000
- Administration and General: 162,000 241,000 301,000 301,000 111,000
- Insurance: 136,000 215,000 297,000 321,000 84,000
- Interim Replacement: 168,000 251,000 316,000 316,000 254,000
- Water-Use Royalty Payments: 230,000 350,000 770,000 950,000 180,000

**Total Operating Costs:** 1,101,000 1,660,000 2,437,000 2,641,000 907,000

**TOTAL ANNUAL COST (2008 $'s):**

- Annual Generation (MWh): 97,200 158,200 233,800 264,200 82,300
- First Year Cost of Energy: 11.74/kWh 11.34/kWh 10.54/kWh 10.14/kWh 8.84/kWh

3.4.2.5 Potential Revenue Sources

3.4.2.5.1 Project Hydro Generation

In an offering memorandum by Similkameen Hydro-Power Ltd, dated November 20, 1992, the developer stated that about 1/3rd of the Project generation would be sold to Princeton Light and Power Company (PL&P) with the balance sold to BC Hydro and West Kootenay Power (currently FortisBC). In January 2007, PL&P customers officially joined the FortisBC customer base. The project energy produced by a hydroelectric project in the Similkameen Basin would presumably be used by FortisBC. The storage component of the large hydro facility would be of high value to FortisBC or any other utility, which could probably support a higher energy cost over a smaller hydro installation with minimal storage.

One aspect of the project operation would be time of day operation, e.g. would the project be operated as a base-load plant with constant flow releases from the power plant or would the project be a peaking plant that could operate on a constant basis for 16 hours Monday through Friday, with little or no generation during the other months, except during the freshet months of May through mid-July. Current environmental regulatory requirements may limit the rate of project ramping such that a hydro plant operation would be limited, unless a downstream regulating dam were added to the project development. Such a dam would allow the Similkameen Project to provide peaking generation while regulating the flows to produce a constant base-flow downstream of the project.
3.4.2.5.2 Headwater Benefits to Downstream Hydro Projects

3.4.2.5.2.1 General

The other potential revenue source for project development could come from existing or new hydroelectric developments that are located downstream of a Similkameen Storage Project. These hydro projects were previously identified in an earlier study by Griffing Consultants Inc. dated May 1992. In that study, Griffing estimated the increase of Enloe Project generation from flow regulation of an upper storage project (per the 1992 EBA recommendation) to be about 2.2 GWh.

3.4.2.5.2.2 Enloe Hydro Project

Based on our initial review and analyses, if a large storage project were constructed in the Similkameen Basin at the Pumphouse site, significant increases in generation would occur at the proposed Enloe Hydroelectric Project due to flow regulation, which reduces the stream flow during the fresher months when the hydro plant would be at full output and spilling water over its dam and increases flow in other months when the Enloe Project could generate more due to lack of water. With the large 500-ft-high (152.4 m) Pumphouse Dam, we estimate additional generation from headwater benefits to be slightly greater than 9 GWh annually, or an increase of project generation of 20%. More importantly, the generation would occur during the non-fresher months when the value of energy would be highest.

If Shanker’s Bend storage dam were to be constructed, the headwater benefits from an upper Similkameen River storage dam may diminish somewhat.

3.4.2.5.2.3 Columbia River Hydro Projects

On the Columbia River, there are nine large hydro projects installation from Wells through Bonneville Dam. Griffing estimated that from flow regulation from a large Similkameen Storage Project would result in a shift of generation during the non-fresher months that would result in additional annual benefits of about 600 kwh/acre-foot (0.486 kwh/m³) of storage, which is based on optimistic storage to energy conversion assumptions that would show downstream Columbia River projects generation increase of 98 GWh. If we assume that only 80% of the available head between Wells and the Pacific Ocean could be realized for 80% of the Similkameen Dam storage (164,000 acre-feet useable)[202 Mm³], with an average plant efficiency of 02%, then 69 GWh of additional energy would occur for these Columbia River hydro projects from a Similkameen storage project. If the revenue could be captured from the additional 69 to 98 GWh, such a revenue boost could help make a Similkameen Storage Project more economically attractive.

The study did not comment on whether reaching an agreement with the downstream hydro project owners was achievable to obtain such additional revenue. The downstream owners include Bonneville Power Administration (BPA) for the McNary, John Day, The Dalles, and Bonneville Dams (all COE operated) and Douglas, Chelan and Grant PUDs for the Wells, Rock Reach, Rock Island, Wanapum and Priest Rapids Dams.

As many of the US Hydro Projects are under FERC license, they are bound by regulations that seek payment to upstream storage projects located in the United States. Such regulations per 18 CFR §11.11 might be the basis of negotiating a fair agreement for compensation of a Similkameen Storage Project. The basis of payment is prorated by net energy gained of all downstream users plus the storage
project. Payment would only be for the interest, depreciation and operating costs of the dam and reservoir, and not for other project components, e.g., power plant and headrace tunnel. As the dam component represents approximately 75% of the development costs and if headwater benefits to the lower projects could be shown to be equal to the project generation, about 15% of the project operating expenses (20% x 75%) could be supported by other parties. Under this formula, the cost of energy to the owners of the downstream hydro project would be about 5¢/kWh and the cost of energy from the Project would be approximately 8.5¢/kWh.

As part of a future project-specific feasibility, discussions with the downstream ownership group is needed to discuss their willingness to support a Similkameen Storage project through royalty payments, and what acceptable additional energy calculations would suffice. Again FERC suggests the use of reservoir operational model in estimating energy with and without a storage project in deriving royalty payments. The Columbia River system has been extensively modeled as a part of new operating parameters for increasing spillage during the freshet months when Salmon species are migrating up the River. In general with reduced hydro operation, there is a corresponding reduction of spill. Therefore, it stands to reason that flow regulation from a Similkameen Storage Project would result in increased generation for the downstream U.S. hydro projects on the Columbia River. It also is recognized that the value of the generation during the non-freshet months is greater than during the freshet months. Therefore, the Columbia River stakeholders could be willing to pay more than 5¢/kWh generation.

3.4.2.5.3 Carbon Credits

Because the Project is a hydroelectric facility that uses a renewable resource to generate electricity, it will qualify for carbon credits under the Kyoto protocol and can thereby receive additional revenue through the sale of its carbon credits. While the Project does have a reservoir, its impoundment size would be sufficiently large that it would need to consider the effects of carbon emissions from woody debris and from the lost vegetation resource that would be displaced with a reservoir.

An assessment of the amount of pollutants involved would need to be determined; based on other thermal generation plants with which we are familiar, the amount of pollution could be anywhere from 400 to 800 tonnes CO2/GWh. Assuming an Intermediate amount of 600 tonnes CO2/GWh and assuming that $15/tonne could be received from carbon trading, then the carbon revenue could be as much as 0.9 ¢/kWh.

For other similar projects with which we are familiar, revenue from carbon credits is assumed up until the year 2012, which is the end of the commitment period under the Kyoto Protocol. It is likely that a subsequent commitment period will be established but to date no legally binding requirements have been established beyond 2012 and therefore no revenue contribution has generally been accounted for. As storage project, if it were to be developed, would likely not be in commercial operation until after 2012, inclusion of any revenue from carbon credits would currently be considered speculative.
3.4.2.5.4 Water Pricing

The issue of water pricing for downstream users of the Similkameen Storage Project was not previously addressed in the PL&P investigations. Reservoir projects developed by governmental institutions usually provide free water for delivery to irrigation districts as a form of farming subsidy. However, many other projects have been developed on the basis of selling water to end users, with water cost to irrigation users usually sold at less cost than to municipal users. Water for consumptive use would also have a direct effect to hydroelectric projects located downstream on the Columbia River. A Northwest Council organization internet article made reference to Bonneville Power Administration (BPA) information developed in 2003 that estimated annual irrigation withdrawals at 14.4 million acre-feet. Expressed in terms of hydropower production, the annual net withdrawals are equal to 625 MW of average electricity production. At an average cost of $50/MWh in 2006, the value of the water was estimated to be $274 million, or about $20/acre-foot. With the recent rise of energy prices, the cost of water from this analysis would be about $40/acre-foot.

Calculating the hydropower value of irrigation withdrawals is only one way to express the value of water. Other ways would be to compare the cost with other alternatives of development, such as from the Shanker’s Bend Storage Reservoir, or from aquifers deep into the ground if they can be identified separate from the surface groundwater source that is directly connected with and an extension of the Similkameen River source. Pumping water out of the ground or over land to higher elevations is energy-intensive. A USA article (Edwin Clark April 2007) stated that pumping 480 cubic meters of water a height of 100 meters requires some 200 kWh of electricity. At a price of 10 cents/kWh, the cost is $20, which does not include the pump, well and piping. This would be equivalent to approximately $50/acre-foot. One hundred meter lifts is not unusual lift for wells tapping ground water. In northern China lifts of 1,000 meters are sometimes required. In Arizona pumping lifts in excess of 300 meters is common. If water were to be extracted by the Copper Mountain Mining Company from a Similkameen Storage Reservoir rather than from the river bottom, considerable savings in pumping energy production would be achieved that could justify a price in excess of $100/acre-foot.

3.4.2.6 Increased Storage

The most recently completed study for reservoir development stated that the maximum level of reservoir would be at El. 3050 ft (929.6 m) due to a bridge river crossing near Manning Park (EBA 1994), which is located just upstream of the Similkameen River confluence with the Pasayten River. However, earlier investigations (Griffing 1992) seem to indicate that the maximum size development could be as much as to El. 3116 ft (950.0 m), if it were economically and technically viable to construct a larger dam at the Pumphouse site.

The economic analysis as summarized in Table 16, indicates an that a larger reservoir size could result in further lowering the cost of energy from the development With an increase of water surface to the forest service bridge (El. 938 m; 3,076.6 ft.), a dam at the Copper Mountain site would contain an additional 45,600 acre-feet (56.20 Mm³) over the El. 3050 ft (929.6 m) level.
The 950 m (3140 ft.) level would back water up to Hwy 3 at a point about 1.1 km (3610 ft.) upstream of the Copper Creek Crossing, but would not flood the highway. It would mean that the forest service road would need to be removed, but would increase storage by 120,700 acre-feet (149 Mm³). With the dam site at the Pumphouse location, the storage amount would increase further.

With any future feasibility analysis of a storage project at the Pumphouse site, we would recommend that further optimization studies be performed to establish the preferred size of the project reservoir, which likely is somewhat higher than 3050 ft. (929.6 m), but lower than 3,116 ft. (950 m). The analysis should also include a review of the preferred minimum operational pool. The analysis should also consider the use of gated versus ungated service spillway design. For example, the introduction of 3.0 ft. (0.9 m) high flashboards across the spillway crest for raising the normal maximum pool level could result in significant additional generation benefits.

3.4.2.7 Summary

Based on our review and update of the 1994 EBA estimate of large dam alternatives at the Pumphouse dam site, Option 3, with the largest reservoir, is shown to provide a lower cost of energy than for the other alternatives. The addition of a tunnel would appear to be promising, but evaluation of its construction cost would need to be carefully reviewed.
4. Conclusions and Recommendations

4.1 Conclusions

Set forth below are the principal opinions we have reached during our review of documentation provided to us as shown in Section 5 of this study of a possible multipurpose project in the Similkameen Watershed. For a complete understanding of the estimates, assumptions, and analyses upon which these opinions are based, this Report should be read in their entirety. On the basis of our review, we are of the opinion that:

1. The only apparent storage project within the Canadian portion of the Similkameen Watershed that could provide some measure of improvement to water supply, water quality, flood control and hydroelectric generation would be located upstream of the town of Princeton within the confines of a relatively narrow canyon in the vicinity of the Copper Mountain Mine. Other sites previously identified that were downstream of Princeton would appear to be non-starters due to the extent of a reservoir impoundment that would displace lands with community development or are within Indian Reservation.

2. Of the three dam sites previously investigated within the Similkameen Canyon, the dam site located furthest downstream at the Pumphouse site appeared to be more promising than the site at the Copper Mountain and Saturday Creek sites, principally because it helped to maximize the useful storage and energy potential of the development.

3. Based on a reconnaissance-level cost review of the three storage sites evaluated at the Pumphouse site, the largest reservoir with the maximum 60 MW installed capacity provided the more promising cost of power, which was estimated to be 10.54¢/kWh. If a 3000 ft. (914.4 m) long tunnel were added for increasing the installed capacity to 68 MW, the cost of energy would decrease to approximately 10.14¢/kWh.

4. The total capital requirements of a 600-foot-high (183 m) Pumphouse Dam, a 3000 ft (914.4 m) headrace tunnel and hydro plants with total installed capacity of 68 MW is estimated to be approximately $340,655,000 and could deliver in an average hydrological year an energy amount of approximately 264 GWh.

5. While revenue source from improved firm water supply, water quality and flood control may not be possible, headwater benefit review for the Enloe Hydro Project and for nine Columbia River hydro developments from Wells to Bonneville Dam can be estimated. If such additional energy were included in the Project development, the composite cost of energy development might be lower than 7.84¢/kWh.

6. From the analyses performed to date, a larger dam with increased storage capacity and higher installed capacity could result in increased economic attractiveness. The maximum size reservoir for development may be limited to a level that would not flood Hwy 3, which would be 66 feet (20.1 m) higher than the currently suggested normal maximum pool El. 3050 ft. (929.6 m).
7. A smaller downsized project that would make use of a 240-foot-high (73.2 m) concrete-arch design as oppose to a 600-ft (183.0 m) high RCC dam design, could be developed and deliver energy at a cost of 8.8¢/kWh for a 25 MW installation. However, such a project would not deliver any headwater benefits with respect to water quality, water supply, and flood control or to downstream hydro developments. Also, a much higher percentage of the total generation would occur during the freshet months as oppose to the non-freshet period when the value of energy is greatest.

8. The study currently underway for the Shanker’s Bend site should be investigated for additional feasibility on the U.S. side of the border with a Canadian project.

4.2 Recommendations

If a proponent was interested in pursuing the development of a water storage project in the Basin, the focus of development should be with a large storage project with a dam height in excess of 600 feet (183 m). Additional studies would need to be undertaken to better verify economic feasibility and in defining headwater benefits associated with water quality, water supply, flood control and hydroelectric generation. Obtaining water rights for project development may initially be done to better protect the development costs which are to follow. The following investigations are recommended:

1. Geologic mapping of the dam and powerhouse sites and tunnel alignment.

2. Topographic mapping of the reservoir area with more detailed mapping of the powerhouse, tunnel and dam sites.

3. Geophysical and geotechnical program to better define foundation conditions for structures and tunnelling constraints.

4. Optimization studies of plant installed capacity and reservoir storage size.

5. Development of feasibility level drawings with quantity takeoffs and cost estimate for developing the project.

6. Final reservoir operational studies to estimate Project generation.

7. Perform flood control studies associated with the project development, including assessment of flood damages with and without a specific storage project.

8. Complete studies associated with water shortages during a critical dry year to establish increased of firm water needs that would be beneficial to agricultural, mining and industrial interests within the Basin.

9. With respect to water quality, perform fish survey studies and minimum instream flow studies to establish the threshold level for improved fisheries. This ecological flow requirement could dictate whether the incorporation of a tunnel to the project is beneficial or should be dropped from further development considerations.

10. Initial discussions with BPA, Grant PUD, Douglas PUD, Chelan PUD and Okanogan PUD to
Project that would increase the generation from their hydroelectric projects and establish what payment mechanism, in principal, would be accepted. This would be followed with estimates of additional average annual generation that would be generated from each downstream hydro project from a specific upstream storage project.

11. Complete economic analysis based on expected form of financing resulting in an initial draft pro forma model.

12. If financial feasibility is established, proceed with the preparation of an Environmental Assessment application as required in obtaining the environmental permit for project development.
5. References


8. Pro forma input and results with 2009 Similkameen Storage Dam Hydro Project in-service date, no author and undated.


Figures
Annual Average

Average Discharge (m³/s)

Year

Annual 10 Year Moving Average

Average Discharge (m³/s)

Year

Summer 10 Year Moving Average

Average Discharge (m³/s)

Year

Winter 10 Year Moving Average

Average Discharge (m³/s)

Year

Note: Summer is May to October and Winter is November to April
Similkameen Watershed Study
Similkameen River near Hedley - Hydrographs

Note: Summer is May to October and Winter is November to April
Note: Summer is May to October and Winter is November to April
Note: Summer is May to October and Winter is November to April

Figure 8
Similkameen Watershed Study
Tulameen River at Princeton - Hydrographs
Note: 1) Station Elevation is 700m
2) Summer is May to October and Winter is November to April
Note: 1) Station Elevation is 700m
2) Summer is May to October and Winter is November to April

Similkameen Watershed Study
Princeton Airport - Temperature
Note: 1) Station Elevation is 297m
2) Summer is May to October and Winter is November to April
Note: 1) Station Elevation is 297m
2) Summer is May to October and Winter is November to April

Similkameen Watershed Study
Osoyoos West - Temperature
FIGURE 19
SIMILKAMEEN HYDRO PROJECT - GENERAL ARRANGEMENT

Potential Arch Dam Site

RCC Dam
(1994 Feasibility Assessment Study, EBA Engineering)

Reservoir
EL 3050'

HATCH energy
Appendix A

Listing of Water Licenses
C151036 32.E.021.1.F (PS566894) Shikakoon River Inletion 15.4\% T N 168 DALEN DR PENTICTON BC V2V1V6 PRIN: KENEDUS Current WA 10413001 20001902
C151050 32.E.021.1.F (PS566875) Shikakoon River Inletion 12.1\% T N 168 LORRAINE RD PENTICTON BC V2V1V6 PRIN: HEDLEY Current WA 10781030 00000000
C151061 32.E.002.1.P (PS797001) Shikakoon River Inletion 9.8\% T N PO BOX 127 KERERUOS BC V0N1N0 PRIN: HEDLEY Current WA 10781030 00000000
C151063 32.E.012.1.E (PS566979) Shikakoon River Inletion 15.8\% T N 168 LORRAINE RD PENTICTON BC V2V1V6 PRIN: HEDLEY Current WA 10439113 00000000
C151064 32.E.002.1.I (PS797005) Shikakoon River Inletion 7.4\% T N PO BOX 127 KERERUOS BC V0N1N0 PRIN: HEDLEY Current WA 10439113 00000000
D091478 0904 DB (PS583893) Shikakoon River Domestic 599 OD M N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current Sec. 18 Amendment 10730403 0
* 32.E.002.1.I (PS567005) Shikakoon River Inletion 28.9\% T N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current Sec. 18 Amendment 10730403 0
* 0904 EE (PS584072) Shikakoon River Domestic 599 OD M N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current Sec. 18 Amendment 10730403 0
* 32.E.002.1.I (PS567005) Shikakoon River Inletion 28.9\% T N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current Sec. 18 Amendment 10730403 0
F093568 0905 23 (PS566412) Shikakoon River Inletion 19.9\% T Y VEGETATION FORMER LAND AND LIVESTOCK CO MAN MAPLE ST VANCOUVER BC V6V1V6 PRIN: PERCETON Current WA 10530002 0
F091571 6010 CG (PS584347) Shikakoon River Inletion 28.4\% T N 168 LAKEVIEW DR & R. JUNE PRIN: HEDLEY Current WA 10730421 0
F091602 60.E.021.1.J (PS797046) Shikakoon River Inletion 30.2\% T N SWINGING G RANCH LTD KEN GEORGE RD RICHARDS BC V0X1X9 PRIN: KERERUOS Current WA 10459091 0
F091626 82.E.012.1.C (PS583757) Shikakoon River Inletion 30.4\% T N SITE 76 CORP 13 RN 1 KERERUOS BC V0X1X9 PRIN: PERCETON Current WA 10439113 0
F091637 82.E.012.1.C (PS583757) Shikakoon River Inletion 19.6\% T N SITE 76 CORP 13 RN 1 KERERUOS BC V0X1X9 PRIN: PERCETON Current WA 10439113 0
F091692 6641 TC (PS566670) Shikakoon River Inletion 65.7\% T N PLEASE CONTACT NEAREST MINISTRY OF ENVIRONMENT WATER MANAGEMENT OFFICE PRIN: HEDLEY Pending Appointed Priest 10590024
F092114 60.E.14.1.L (PS797045) Shikakoon River Inletion 3.6\% T N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current WA 10502226 0
F092558 32.E.012.2.J (PS566679) Shikakoon River Inletion 129\% T N STEWART FARM G 2014 3RD ST VANCOUVER BC V6Y1Y8 PRIN: KERERUOS Current WA 10506423 0
F092794 82.E.012.1.K (PS569577) Shikakoon River Inletion 100\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
F093075 60.E.13.1.J (PS797042) Shikakoon River Inletion 29.5\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
* 60.E.012.1.L (PS566679) Shikakoon River Inletion 100\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
F093372 6012 DD (PS566542) Shikakoon River Inletion 114.8\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
* 6012 2 (PS566539) Shikakoon River Inletion 114.8\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
F093623 6012 DD (PS566542) Shikakoon River Inletion 114.8\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
* 091373 6012 DD (PS566542) Shikakoon River Inletion 114.8\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
* 6012 2 (PS566539) Shikakoon River Inletion 114.8\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
F093635 6014 UU (PS567272) Shikakoon River Inletion 3.2\% T N 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10506428 0
C151045 6014 UU (PS567272) Shikakoon River Inletion 14.5\% T N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current WA 10829420 0
F092035 6009 WH (PS568796) Shikakoon River Inletion 14.5\% T N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current WA 10829420 0
F092035 6009 V (PS568796) Shikakoon River Inletion 14.5\% T N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current WA 10829420 0
F092035 6009 WH (PS568796) Shikakoon River Inletion 14.5\% T N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current WA 10829420 0
F092035 6009 V (PS568796) Shikakoon River Inletion 14.5\% T N PO BOX 211 HEDLEY BC V0X1X9 PRIN: HEDLEY Current WA 10829420 0
F100000 02.E.021.2.B (PS563193) Shikakoon River Inletion 238\% T N S 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10430413 0
F100000 02.E.021.2.A (PS563193) Shikakoon River Inletion 238\% T N S 168 LAKEVIEW DR & R. JUNE PRIN: KERERUOS Current WA 10430413 0
E100505 BENTLEY (PS551648) Shikakoon River Power-General 1250 bos T N SUITE 100 1975 SPRINGFIELD ROAD KELOWNA BC V1Y2Y9 PRIN: PLETZON Active Application 10499658 0
* 32.E.002.1.I (PS567005) Shikakoon River Inletion 100\% T N 168 LAKEVIEW DR & R. JUNE PRIN: HEDLEY Current WA 10730403 0
