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Presented by: **Eri A. Boye**

Master of Science Thesis:

A feasibility and economic study into the use of micro hydro power applications to generate electricity from the Victoria *Capital Regional District's* municipal water facility.

Victoria, British Columbia, Canada.

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February 2011

A feasibility and economic study in the use of micro hydro power applications to generate power from the Victoria *Capital Regional District's* municipal water facility.

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CAPITAL REGIONAL DISTRICT
Water Services

By: Eri A. Boye

Supervisors:

Mr. Tim Tanton
Mr. Jónas Elíasson
Mr. Helgi Jóhannesson

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Master of Science
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Student:

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Examiner(s):
(Print Name and Date)

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QUOTES:

“My method is different. I do not rush into actual work. When I get a new idea, I start at once building it up in my imagination, and make improvements and operate the device in my mind. When I have gone so far as to embody everything in my invention, every possible improvement I can think of, and when I see no fault anywhere, I put into concrete form the final product of my brain.” - Nikola Tesla

“Work smarter, not harder.” - Eri A. Boye

ABSTRACT:

The Victoria *Capitol Regional District* (*CRD*) operates several pressure reducing facilities (PRF) as part of their potable municipal waterways. The Humpback PRF has the largest flow and head conditions, and was used as the study site in this thesis. A feasibility and economic study was conducted to observe the viability of a proposed hydropower station at the Humpback PRF.

Feasibility analysis of flow and pressure:

Flow and head conditions vary over the course of time, with lows in 2004 of 0.2 cubic meters per second (m^3/s) and 15 meters (m) of head, to highs in 2009 of 2.3 m^3/s and 67 m of head. The Sooke Reservoir is the source of water and has a head tank open to atmospheric conditions at an elevation of 169 m.a.s.l. The proposed centerline for the hydro turbine runner is around 109 m.a.s.l., allowing for a brute head of 60 m at that point. Frictional headlosses were calculated, and are not as significant as the head losses that result in the treatment plants. Average flow and head conditions were established, and used to determine the turbine design size, and were found to be:

- 1.3 cubic meters per second
- 48.0 meters of head.

Economic analysis:

RETScreen, a free downloadable program created by The Government of Canada, was used to perform six (6) economic scenarios. Two (2) export price rates were set, and applied to three (3) economic scenarios: best, expected, and worst case resulting in the six different scenarios. Market options, penalties, ownership options, and future steps were examined. A summary of the Humpback PRF power potential was provided by RETScreen and is listed below:

Proposed Turbine Size: 426 kW (.426 MW)
Power Output (80.8% capacity factor): 3,014 MWh

The economic potential of this project was studied with two prices and under a best, an expected, and a worst case scenario. The best case scenario with the higher electricity export price rate had a rate of return of over 60% on the equity invested. In contrast, the worst case scenario with the lower electricity export price rate had a return on investment of -6%. Penalties and other accrued costs were not incorporated in either of these rates of return but are noted within this paper.

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Many more friends and family: you are not forgotten, and neither are the huge contributions that you have so willingly donated to help me.

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- Mr. Raymond Fung at the District of West Vancouver – Engineering and Transportation
- Mr. Bruce Sellar and GILKES at Vancouver Island Technology Park
- Mr. Tim Tanton and everyone at the Victoria Capitol Regional District – Integrated Water Services

PREFACE:

The ability to access hydropower and potable water delivery systems are essential to human life as we wish it to be. The global human demand for electricity and fresh water is ever increasing. Due to the nature of hydropower and its economic, social, and environmental benefits, hydropower will be an important contributor to the energy mix of the future.

Water delivery, and the ease of availability to fresh water for all people, is an essential human service. Water delivery infrastructures have a huge scope of sizes and shapes. In some poorly developed parts of the inhabited planet, no water delivery infrastructures exist at all. As the inhabited portions of this planet grow, there will be an increasing demand for both electricity and water delivery and use. The areas on earth that have the greatest need for hydropower also have the greatest potential.

Any infrastructure development involves an environmental footprint, and there is a global growing thirst for electricity and fresh water storage. It is the proposed idea in this study to combine the ideas of hydropower and distribution waterways. In the case studied, the Victoria (British Columbia, Canada) *Capital Regional District*'s (*CRD*'s) municipal potable waterways were observed. A proposed location for a turbine was studied, and this location was at the *CRD*'s Humpback Pressure Reducing Facility (PRF).

The role of this paper was to:

- Provide background information regarding electricity and municipal waterways including the *CRD*'s waterways to the Humpback PRF
- Analyze Flow (l/s or m^3/s) and Head (m) feasibility conditions over the course of 2004, 2005, 2006, 2007, 2008, and 2009
- Calculate the potential head losses due to friction in the waterways
- Develop a turbine size for the proposed hydropower processes
- Perform economic analyses under varying long term conditions
- Highlight important aspects, processes, penalties, or future steps of the proposed project
- Inform the CRD of the feasibility and economic hydropower potential at the Humpback PRF

It should be noted that hydropower projects are flexible in nature, can be implemented in non-traditional ways, and could be used on existing waterways to generate electricity as a by-product, or as part of a combined cycle.

ABBREVIATIONS AND ACRONYMS:

kW	Kilowatt
MW	Megawatt
kWh	Kilowatt Hour
MWh	Megawatt Hour
GWh	Gigawatt Hour
B.C.	British Columbia (BC)
CHP	Combined Heat and Power
HRSG	Heat Recovery Steam Generators
CCPP	Combined Cycle Power Plants
PRF	Pressure Reducing Facility
PRV	Pressure Reducing Value
UV	Utra-Violet
LCA	Life Cycle Assessement
CRD	*Capital Regional District*
m.a.s.l.	meters above sea level
TBM	Tunnel Boring Machine
CFD	Computational Fluid Dynamics
FDC	Flow Duration Curve
SOP	*BC Hydro's* Standing Offer Program
IRR	Internal Rate of Return
CND	Canadian Dollars ($)
USD	United States Dollars ($)
tCO_2	Tones of Carbon Dioxide

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1) INTRODUCTION:

1.1) GOAL & SCOPE:

The purpose of this study is to quantify the power generating and economic potential of a proposed micro hydro generation station at the Victoria *Capital Regional District's (CRD)* Humpback Pressure Reducing Facility (PRF). The proposed idea involves a combined cycle technique, combining the current *CRD* municipal waterway system with a potential hydro turbine. This turbine would be introduced to the local potable water system, and would be physically in contact with the local water in those waterways. Any surplus kinetic and/or potential energy in the water flowing through the Kapoor Tunnel and connected waterways were studied for the possibilities of generating electricity from them. The Humpback PRF is currently part of this system and is used to control the pressure of the water coming from the Sooke Reservoir.

This analysis was done by quantifying the availability of water discharge and pressure heads for the purpose of power generation. Water discharge and pressure head values were provided by the *CRD*, and measured at the Humpback PRF.

The goals of this study were to create a stochastic model showing the variations in water discharges (liters per second, or cubic meters per second) and pressure heads (meters) over the course of a day, month, year, as well as to determine a range in values that could be used in a turbine design. Data was obtained for the years 2004 to 2009. An economic analysis was also included to determine the practicality of this project.

Is it possible that every time a faucet is turned on, it could also be initiating a combined process that generates electricity?

1.2) BACKGROUND INFORMATION:

The *Capital Regional District* (*CRD*) has approximately 20,000 hectares (ha) of protected water supply lands that are dedicated to supplying potable water to the 340,000 residents of the Greater Capital Region (Capital Regional District, 2010). Precipitation is captured from the Sooke Watershed and stored in the Sooke Reservoir which is located northwest of the City of Victoria at an elevation of approximately 175 metres above sea level (m.a.s.l.).

From the Sooke Reservoir, the municipal water flows into a head tank which is under atmospheric conditions (open to the atmosphere and not under additional pressure) at an elevation of 169 m.a.s.l. This water then travels through the 8.8 km long Kapoor Tunnel to the Japan Gulch Ultra Violet (UV) and Chloramination Plants before it reaches the Humpback Pressure Reducing Facility (PRF) (Figure 1) (Capital Regional District, 2009). The Humpback PRF is the largest *CRD* facility in terms of flow and pressure across the valves, and has the greatest potential for hydroelectric generation (Planit Management and Stantec Consulting, 2004).

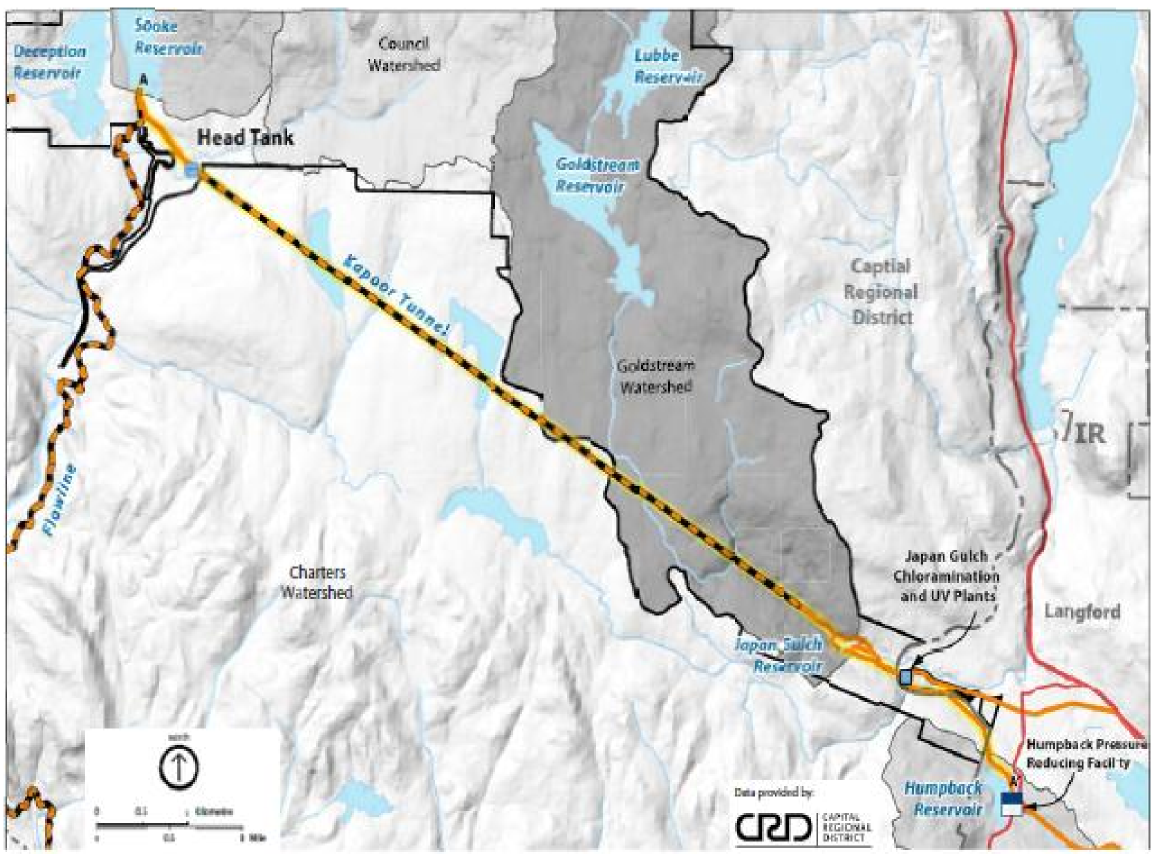

Figure 1: System overview of the flow path of water through the Sooke Reservoir, Head Tank, Kapoor Tunnel, Japan Gulch Chloramination and UV Plants, as well as the Humpback Pressure Reducing Facility. Figure courtesy of the CRD (Capitol Regional District, 2008).

Data measurements on flow rates and pressure heads were provided from the Humpback PRF since 2003. In 2007, which is assumed to be a typical year, the flow rates ranged from a low of 0.1 cubic meters per second (m^3/s) to a peak of 2.5 m^3/s, (Capitial Regional District, 2009). The elevation difference between the aforementioned head tank and the downstream side of the Humpback PRF totals approximately 56 meters. Frictional head losses are estimated to be between 4 to 18 meters of head; singular head losses have not yet been calculated (Planit Management and Stantec Consulting, 2004).

A few key market feasibility components have been examined for this project. These include two rates at which the electricity could be sold, as well a best, an expected, and a worst case scenario under these two prices. All of these scenarios would require gaining physical access to the market via the electrical grid. This could be done by interconnecting the proposed Humpback Power Station with the current distribution grid. Two other ideas that will be mentioned in this report include 1) finding a non *BC Hydro* buyer for the electricity and 2) using the potential power produced onsite in the Japan Gulch Chloramination and UV Plants.

1.3) FEASIBILITY STUDY:

The first step in this study was to gather the historical flow rates and pressure values collected by the *CRD*. The *CRD* collected data on an hourly basis for the years of 2003 to 2009 at the Humpback PRF (Figure 2). A typical yearly data set consists of 8760 entries representing an entry at the beginning of every hour on every day for a year. In cases where there were gaps within the data, due to temporary failures of the measuring equipment, the record system, or any other reason, the gaps were noted and removed from the analysis. The data sets were carefully screened for anomalies.

- A set of statistical and stochastic tests were performed on the data sets
- A relationship between head (m) or pressure and the flow rates (L/s, or m^3/s) was determined

- Head (m) losses were roughly calculated to determine the head losses by friction in the waterways
- This feasibility study helped to constrict the turbine(s) and power plant size, which was used in the economic study

Figure 2: The view inside of the Humpback Pressure Reducing Facility (PRF). Two of the three existing pressure reducing values (PRV) are shown, with the other one located to the left of the picture (Planit Management and Stantec Consulting, 2004).

1.4) ECONOMIOC STUDY:

Economic factors were examined to determine an appropriate turbine(s) type and size. Some design factors, like those required by the *CRD*, have no flexibility in them and are nonnegotiable. These include, but are not limited to minimizing safety risks to the potable water, operational health and safety, precise downstream pressure control, *CRD* flexibility with regard to operating schedule, and a fundamental priority that potable water be the primary purpose of the *CRD*'s waterways.

RETScreen is a clean energy project analysis software created and distributed by Natural Resources Canada (Natural Resources Canada, 2010). It was used to test the economic and power generation potential of a turbine being introduced into the *CRD's* waterways at the Humpback PRF. Suitable pressure head (m) and flow rate (L/s, or m^3/s) values from the Humpback PRF were used as inputs in the RETScreen analysis. A set of output values and results to a range of scenarios was produced using this software.

Three economic scenarios were created:

- Best case
- Expected case
- Worst case

These scenarios have a set of different resulting rates, costs, incentives, and outputs. A short summary of some outputs from RETScreen are and shown below (Table 1).

Table 1: Economic Output from RETScreen.

Pre-tax IRR - equity
Pre-tax IRR - assets
Simple payback
Equity payback
Net Present Value (NPV)
Annual life cycle savings
Benefit-Cost (B-C) ratio
Debt service coverage
Energy production cost
GHG reduction
CO2 Car/light Truck
CO2 40yr Reduction

The RETScreen analysis was used to determine if the studied conditions of the project are economically and/or technically feasible.

Two key market *Trial Prices* were looked at for this project. A best, an expected, and a worst case scenario were examined for these *Trial Prices*. This process would require gaining physical access to the market via the electrical grid. *BC Hydro* would therefore have to be included in this process from its conception.

A number of incentives, debt interest rate, interest rate, discount rates, construction and development costs, as well as other factors were inputted into RETScreen. These and many other variables set the analysis conditions in RETScreen, whereas the algorithms and codes used for the calculations were created by the program. All of these economic variables were then compared with a series of third party involvement scenarios. Any future decisions based on the findings within this paper will need to be made by the *CRD*. Furthermore, should the *CRD* decide to advance towards project construction, a formal process would have to be presented to the *B.C. Water Supply Commission Board*. Permitting is also part of the advancement process, as could be a possible environmental impact assessment (EIA).

1.5) EXPECTED RESULTS:

It was expected that an accurate design range for pressure head (m) and flow (L/s, or m^3/s) values would be calculated. This set of conditions was then inputted to calculate the electricity power generation potential for the Humpback PRF. This design range should account for or acknowledge the possibility of head losses from both friction as well as singular losses.

It was expected that three economic scenarios would be created: a best, an expected, and a worse case. These three economic scenarios would then be run with two *Trial Prices*. These scenarios would have a series of calculated variables, i.e. construction costs, annual revenues, annual operating costs, and rates of return on the investment. It was expected to then be able to determine, under the studied conditions, if the project is economically and technically feasible.

1.6) LIMITATIONS:

The focus of this thesis is in the fields of Engineering, Sciences, and Economics. A combined system approach, combining municipal potable waterways and hydropower, was used in this study. Despite both of these systems being fundamental to a developed world, they are not commonly found working symbiotically on the same system. There is limited publically available literature regarding this combined system. A few engineering companies have looked into this possibility, and have even successfully installed this idea in places such as Boulder, Colorado, U.S.A. Other municipal waterways have attempted this process as well, with similar systems operating in cities in the United Kingdom, as well as locally, in West Vancouver, British Columbia, Canada. Most of the municipalities and the engineering firms that work on these cases are not readily willing to give out information. As a result, mistakes are repeated and/or the technology can not freely progress or advance. The author of this paper would like to note at this time that much of the provided material used in the analysis was asked by the providers not to be made public.

The statistical analysis process was thorough, and as a result time consuming. The project also acknowledges that there was a limited time to complete this thesis. Time constraints limited the depth of the study. For such a project to come to fruition, many resources must be allocated to it. The concept of ordering a generation unit and powerhouse tailored to a set of conditions takes time, and it has to be forged from scratch.

2) BACKGROUND:

2.1) AN INTRODUCTION TO ELECTRICITY:

The human journey, especially throughout the last 200 years or so, has been based largely on our improving ability to convert available energy into forms that are useful to us. From the times humans have walked on this planet, lightning has occurred, a visible and dramatic show of the power that can exist in electricity. Another long know source of electricity is from animals; for example, more than one type of fish was recorded in Egyptian texts to be able to shock a target. It should be noted here that the concept of relating hydropower to electricity is a modern one. At least 2000 years ago people were using water to move wheels that would allow for the grinding of grains which was part of the process to make breads (National Energy Education Development, 2010).

After hundreds of years of study, Benjamin Franklin popularized the idea that electricity could be captured and used as he hooked a kite up to a key in 1752 and flew it into a storm sending shocks to the touch and sparks (National Energy Education Development, 2010).

Alessandro Volta, an Italian scientist, was the next prominent figure. He created the first electric cell by soaking paper in salt water. Once it was sopping wet, he placed zinc and copper slugs on opposite sides creating a chemical reaction which produced an electric (National Energy Education Development, 2010). Volta has since been honoured by the SI unit system, with the Volt (V) being a measure of electromotive force.

In the study of hydro power, hydro power generation, or hydro electric power plants (HEPP), the ingenious English physicist and chemist Mr. Michael Faraday must be mentioned. He is credited with discovering the magical process that happens when a magnet is passed through a copper wire, producing an electric (National Energy Education Development, 2010). He also discovered the physical electromagnetic force and benzene, and popularized the terms Volta had worked on: anode, cathode, electrode, and ion. He has also been honoured by the SI unit system; Farad (F) is a measure of capacitance and the Faradays Constant is a known value of the charge on a mole of electrons. Almost all the hydro electricity that is harnessed today comes from a process involving magnets and coils of copper wire. These processes and principles can be commonly seen in electric generators and electric motors.

In 1879, a switch went off in Thomas Edison's brain and all his years of hard work trying to find a filament in a light bulb came to fruition as he took common cotton thread and soaked it in carbon, creating a long lasting iridescent light (National Energy Education Development, 2010). 1879 also marked the year of the first HEPP, which occurred at Niagara Falls (National Energy Education Development, 2010). Mr. Edison then opened his own power plant in 1882, and provided limited electricity to the very local vicinity using a direct current (DC) at a steep price of $5.00 per kWh (National Energy Education Development, 2010). In 1895, George Westinghouse initiated a new HEPP at Niagara Falls and was able to transmit this electricity over 200 km to customers using an alternating current (AC) (National Energy Education Development, 2010). This was just the beginning of an avalanche of change that would occur on the electrical landscape.

The story of humans and electricity is a complex and continuously evolving one. Being that, one thing has remained relatively constant and that is the ever increasing demand for energy that humans are after. We have a growing thirst and hunger towards the availability, acquisition, storage, and use of energy, especially in the form of electricity. In fact, "in 1920, only two percent of the energy in the U. S. was used to make electricity. Today, about 41 percent of all energy is used to make electricity" (National Energy Education Development, 2010). As the global demand for technology increases, and as economically depressed countries develop, this trend will inevitable continue.

2.2) AN INTRODUCTION TO HYDROPOWER:

As was mentioned at the beginning of the previous section, *An Introduction to Electricity*, the concept of relating hydropower to electricity is a modern one. Hydropower also called hydraulic or water power, is essentially a way of using water's kinetic (mechanical) and/or potential energy to perform a useful task or process. The word "hydro" is Latin for "water". Water power has been used for thousands of years in various forms of irrigation (and as municipal water), and by various geographically located people on this planet Earth. It has been used to power many different types of mills, cranes, and lifts, and has also been used as a leveling device, clock, seasonal indicator, and for many other functions. Most importantly, water is needed in the human physiological processes and is paramount for most of the life and many of the naturally occurring processes on this planet.

Hydropower, and life as we know it on this planet, would not exist if it was not in part for the hydrologic or water cycle (Figure 3). This cycle has infinite starting points. These include the processes that water undergoes as it is heated by the sun and evaporates into the air, is transported, and then is deposited back to the surface of the Earth in the form of a precipitation type. It is important to acknowledge the delicateness and the complexity of the water cycle. Our understanding of the water cycle has evolved over time and it is intimately studied for many of its complexities.

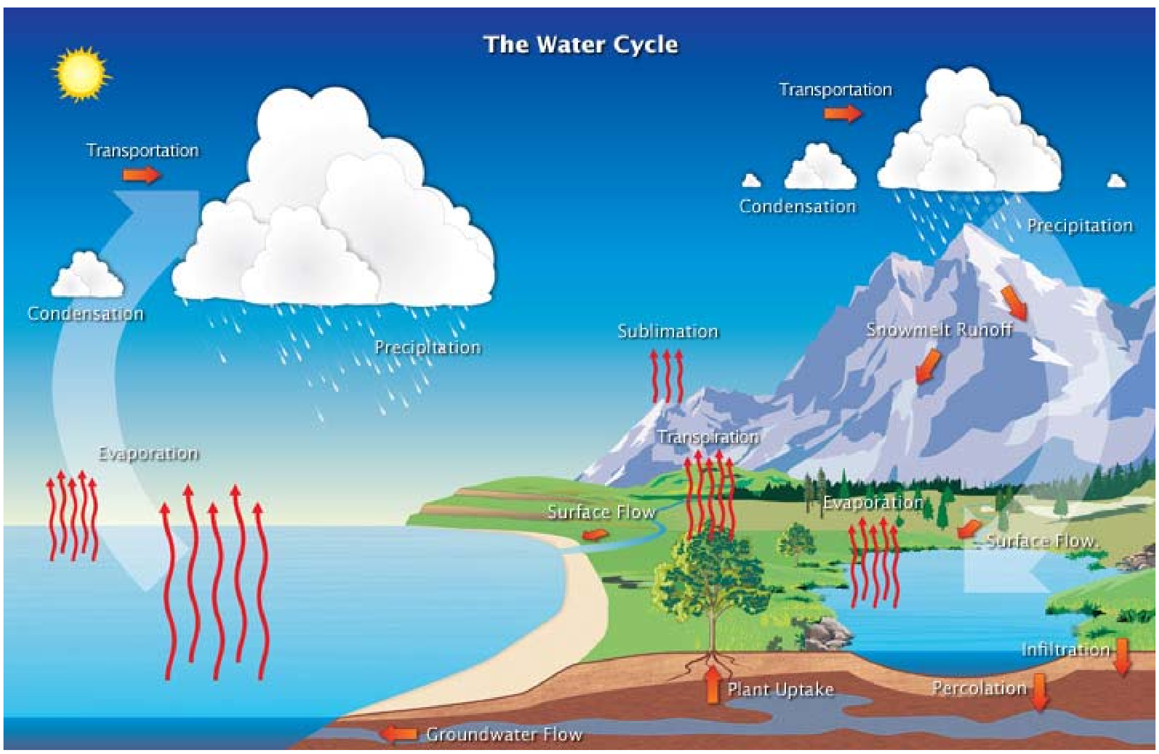

Figure 3: The Water Cycle, as depicted by NASA (NASA, 2010).

The current understanding of the water cycle incorporates the many paths that water travels above, below, as well as through the earth and the many varieties of water columns on this planet. This cycle also includes the paths in and out of the plant and animal cycles (photosynthesis and respiration) and through both the short and long term reservoirs. Many academic endeavors and scientific journeys have been undertaken to study water in all of its complexity. We are still unlocking many of the secrets that water holds, and are learning how it behaves in its many complex cycles. It is because of this water cycle that hydropower is considered to be a renewable energy source. Under the current conditions on planet Earth, as long as free water runs, the sun shines, precipitation falls, the tectonics cycles occur, human ingenuity exists, and gravity exerts its force, the possibility of using hydropower could be endless.

The general concept of a HEPP is to convert the kinetic and potential energy of the water (mass) moving with some speed (momentum) into a usable form of energy – electricity. As was mentioned above in *An Introduction to Electricity*, the first hydropower plant went into production in 1879 at Niagara Falls. Although the modern day scale of damming and power outputs are much greater than ever before, the process of generating electricity has remained relatively unchanged. The example below (Figure 4) shows a general case involving a dam and reservoir (energy storage device). The reservoir is connected to the powerhouse via tunnels/piping, which allows for the flow of water across a turbine. This water then exits the system as it empties into a river (via piping/trenching).

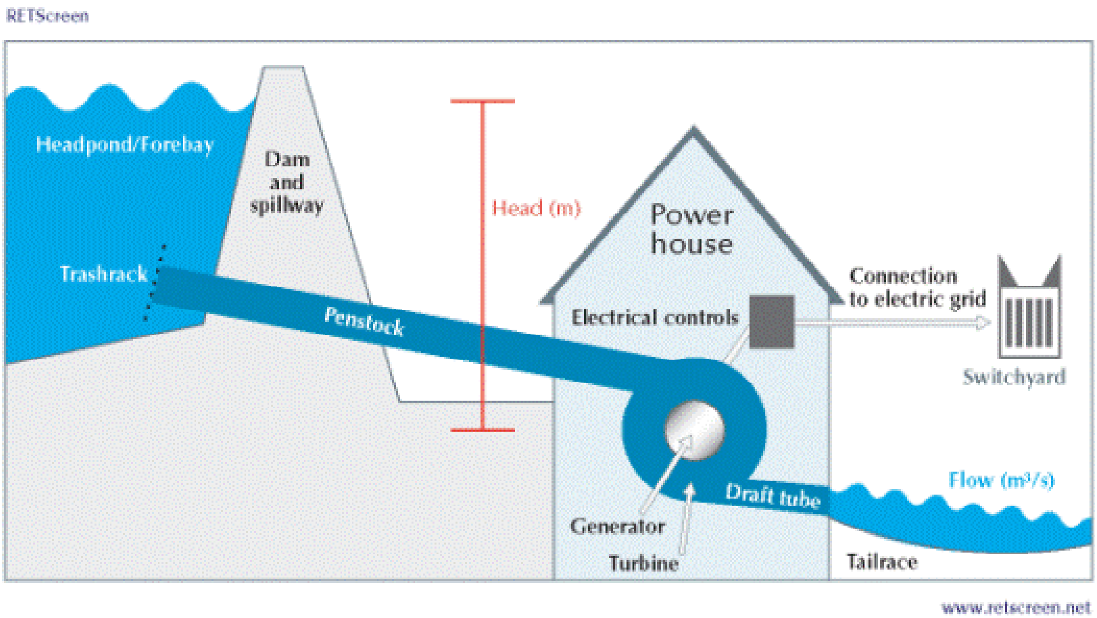

Figure 4: RETScreen schematic of a generic dam, waterway, powerhouse, and switchyard/grid connect.

In contrast, the figure below (Figure 5) shows the current schematic of the *CRD* waterways at the Humpback PRF. (Note the absence of a powerhouse and grid interconnection.)

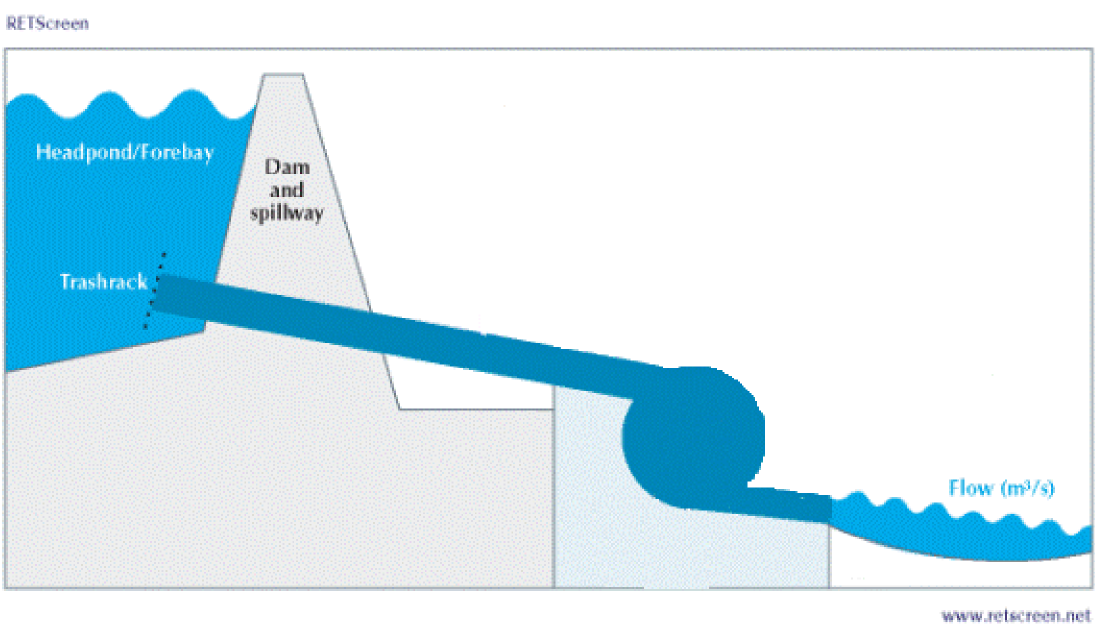

Figure 5: Edited RETScreen hydropower schematic, made to represent the current scenario for the CRD at the Humpback PRF.

It should be noted here that an excitor, or excitation unit, is also needed in this process of electrical generation. As the turbine turns (Figure 6), the excitor (excitation unit) sends an electrical current to the rotor. This current is easily accessible to an operating plant as the locally generated electricity can be used by the excitation unit. However, at the start-up of a plant, the excitation unit is usually powered at first from electricity drawn from the transmission/distribution lines. The rotor is normally composed of a series of large electromagnets that spin inside a tightly-wound coil of copper wire, called the stator (Figure 7). The magnetic field between the coil and the magnets creates an electric current, just as Faraday had shown. This current is then synchronized with the system, and inputted to the power lines via a switch yard.

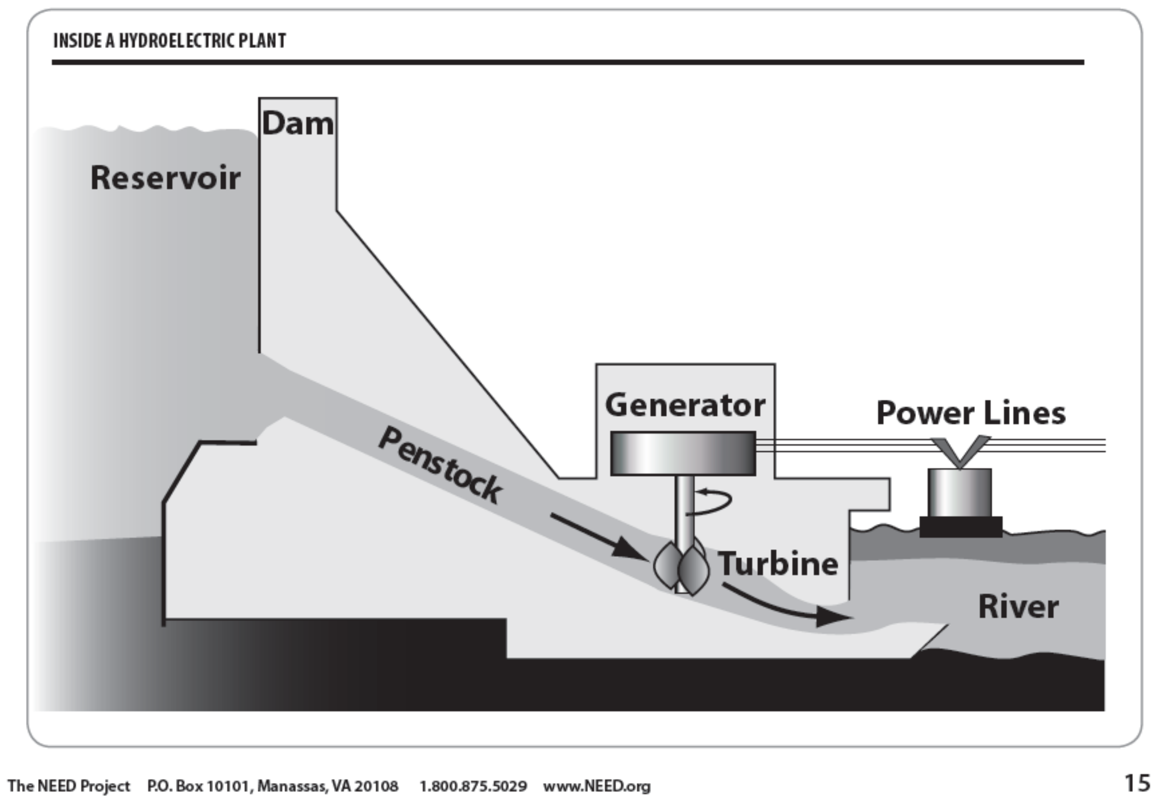

Figure 6: Schematic of a hydropower system. The rotor (spinning) and stator (stationary) are located within the generator. Image provided by the NEED Project, (National Energy Education Development, 2010).

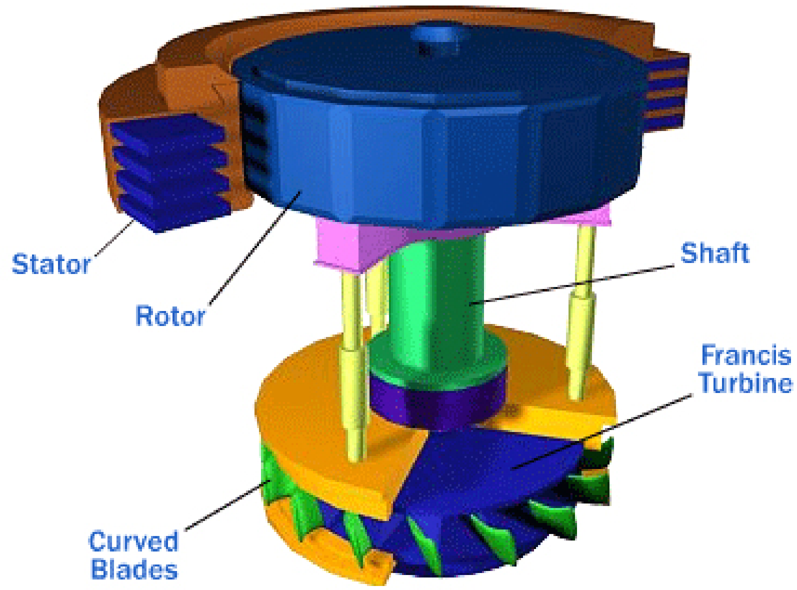

Figure 7: Representative drawing of a spinning Francis Turbine which is connected to a rotor by a shaft. Image provided by ENERGO-PRO, (ENERGO-PRO, 2010)

The development of these relatively simple systems and an understanding of their potential led to a hydropower land and water staking "gold rush". It was estimated by the 1940's that most of the ideal hydropower dam sites had been claimed or developed in the United Stated of America (National Energy Education Development, 2010). It was during this time that the exploitation of fossil fuels, and the intense energy density that they contain, came into popularity. From the 1940's until the 1970's oil crisis, hydrocarbon fired power plants proved to be much more economical than the conventional hydropower choice. The concepts of life cycle assessment, corporate responsibility, and environmentalism started to change public awareness in the developed world regarding the sources of electricity generation. This, as well as the recent global preoccupation with the possibility of anthropogenic climate change, has resulted in a recent revision or revisiting of the fuels or energy sources used for electricity generation. In this modern day, the ability of a country to secure long term energy deposits is at the heart of most political agendas. Over the last 70 years the energy source of choice has been an energy dense, easily transported material - crude oil and, to a lesser degree, coal. It has been speculated that whichever country is able to corner a new energy source, renewable, non-renewable, or a combination of the two, would lead the Earth (at least economically) in the 21st century.

There is the possibility that new revolutionary solutions to the increasing demand for energy will be discovered. However, it is the author's opinion, and the study of this paper, that tomorrow's energy needs can be solved with an increased awareness of energy usage, as well as combining existing systems and using of energy presently available in abundance. There are many cases where combining systems have proven viable, and are proving to be an evolutionary step forward. Passive combined heating and cooling systems have been seen in infrastructure noted back to the Egyptians. Examples of modern day combined cycles include combined heat and power plants (CHP), heat recovery steam generators (HRSG), combined cycle power plants (CCPP), or even the hybrid systems in passenger vehicles.

This paper looks at combining a municipal waterways system that has an existing pressure reducing facility (PRF) (high head conditions (m)) with a hydropower powerhouse. The powerhouse is to include all the components necessary to produce electricity from the normal flow conditions (usage) (L/s) of water in the municipal waterways. This process would allow for the pressure reducing valves (PRV) at the PRF to act as a back-up or relief system. The introduction of a powerhouse and a turbine into the municipal waterways is in no way to have a negative effect on the health and safety of the people working in the area, or on the quality of water that is being distributed throughout the system.

2.3) AN INTRODUCTION TO MUNICIPAL WATER SYSTEMS:

Humans have always been dependant on fresh water, and as a result the global human development has usually occurred within the vicinity of fresh water. Water, and its many marvels, is a keystone in the development of humanity as it aids in transport, health, farming and animal husbandry, as well as in many other areas. If water is not immediately present, it is possible to move it to another location of choice. Gravity and a focused path or channel/piping will allow for water to move downward in elevation, while momentum, pumping, or a natural phenomenon like an artesian aquifer will allow for water to rise to an elevation higher than that at which it originally started.

While it is important to have an ample *quantity* of water for consumption, it is more important that the *quality* of that water is to a standard that does not pose any sort of health threat to anything that many come in contact with it. It has been noted in writings as early as 4000 B.C. that processes were taken to treat the odor and cloudiness (turbidity) of drinking water. Such processes involved filtering water through charcoal, boiling it, straining and/or filtering it, and exposing it to sunlight (United Stated Environmental Protection Agency, 2000). Egyptians as early as 3500 years ago used the chemical alum to initiate suspended particle nucleation, and as a result suspended particles could be removed from a water column as they would settle out of a very slow moving water body (United Stated Environmental Protection Agency, 2000).

In the 1700's filtration began to take off in Europe as a good way to remove sediment from water (United Stated Environmental Protection Agency, 2000). This proved to be more useful than noted at the time as some of the sediment was harmful in nature (for example, suspended rotting organic material or feces and bodily fluids). In the 1800's, slow sand filtration became common in Europe as a way to remove sediments (United Stated Environmental Protection Agency, 2000). There were two major discoveries in the 1800's that related to the fact that water could be a disease carrying agent. In 1855, Dr. John Snow proved that cholera was a waterborne sickness hosted by the sewage in a contaminated drinking water well in London. Also, in the late 1880's, Louis Pasteur presented his "germ theory" that helped to explain how unseen organisms could exist, and how these organisms could be responsible for all sorts of issues including transmitting diseases through a common media form like water (United Stated Environmental Protection Agency, 2000).

Filtration proved to be a decent treatment method for reducing cloudiness (turbidity). However, it was not until 1908 that water treatment became prominent when the first disinfectant (chlorine) was used in Jersey City, New Jersey (United Stated Environmental Protection Agency, 2000). It should be noted that at the same time that chlorine was being used in the U.S. to treat potable water, the gas ozone (O_3) was being used as a treatment option in Europe; this treatment option did not reach the U.S. until several decades later (United Stated Environmental Protection Agency, 2000).

Today, it is common to treat municipal water with filtration and chlorination techniques to remove harmful microorganisms. The addition of chlorine to the system has two dominant effects: an instant killing off effect as well as a longer residual killing effect. The instant effect takes place closest to the source where chlorination occurs, while the longer term effects normally take place in the plumbing and back eddies of the downstream part of the system. However, it should be noted that some microorganisms have become resistant to chlorine and the chlorination process. Other water treatment techniques do exist in the form of reverse osmosis filtration, black or ultraviolet (UV) light treatment, or ozonation (United Stated Environmental Protection Agency, 2000). It is typical in the developed world for municipal water to be controlled by a local governing body or a corporation. In the developing world, especially in the poorest developing countries, this control of the water system has been established to be in the hands of private, foreign corporations. Most countries have regulations regarding the quality of drinking water that is provided to their inhabitants. As water treatment systems and facilities advance, it is the author's thoughts that water treatment facilities will have a larger concern with regard to the full life cycle assessment (LCA) of the water that passes through their plants. This will embody a switch in treatment from a chemical process to an alternate process, resulting in no agent(s) residue in the water. This could mean a shift from chlorination to UV or ozonation to avoid environmental contamination from residual chlorine.

The object of this paper is to point out that human engineering is able to transport water around as it sees fit. Humans are able to pump water up mountains in order to store it as energy to be used later, as is the case in pumped storage. Humans are able to relocate it great distances inland, into some of the driest part of the world, as is the case in Nevada, U.S. Humans are able to convert moving water into electricity. It therefore seems sensible to apply these innovations to the water already being used by municipal water systems. This leads to a concept of a local municipal water system that provides both water and power, wherein a turbine could generate electricity from regional drinking waterways. Is it possible that every time a faucet is turned on, it could also be initiating a process that also generates electricity? It is acknowledged that this type of combined system is not ideal for everywhere, and that is why this paper focuses on the municipal water system controlled by the Victoria *Capital Regional District* (*CRD*) in British Columbia, Canada.

2.4 AN INTRODUCITON TO THE VICTORIA CAPITAL REGIONAL DISTRICT (CRD) MUNICIPAL WATER SYSTEMS:

The Victoria *Capital Regional District* (CRD) banner is seen below (Figure 1Figure 8).

Figure 8: The Victoria CRD Banner. Source: http://www.crd.bc.ca/.

It should be noted that all facts, images, and information regarding the Victoria *CRD* waterways and water systems are provided by the *CRD*, unless otherwise referenced or specified.

The *CRD* is the regional government that is responsible for the 13 municipalities and 3 electoral areas that are located on the southern tip of Vancouver Island, B.C. Canada. The *CRD* estimates that, as of 2011, it provides potable water to approximately 340,000 users. The *CRD's* mission statement is: "The CRD: diverse communities working together to better serve public interest and build a livable, sustainable region." (Capital Regional District, 2009). The *CRD* is responsible for a number of key services and deliverables, and a list of this can be seen in Appendix 1. A 2009 to 2011 strategic action plan developed by the *CRD* and stated the following: "With sustainability as its guiding principle, and the triple bottom line as the lens through which it will make decisions at a time when there are real fiscal limitations and the need for regional leadership, the CRD has identified climate action, environmental protection, housing, regional transportation and waste management, as those issues requiring critical action over the next three years." (Capital Regional District, 2009). The figure below (Figure 9) shows the *CRD* strategic action plan's priorities for the years of 2009 to 2011.

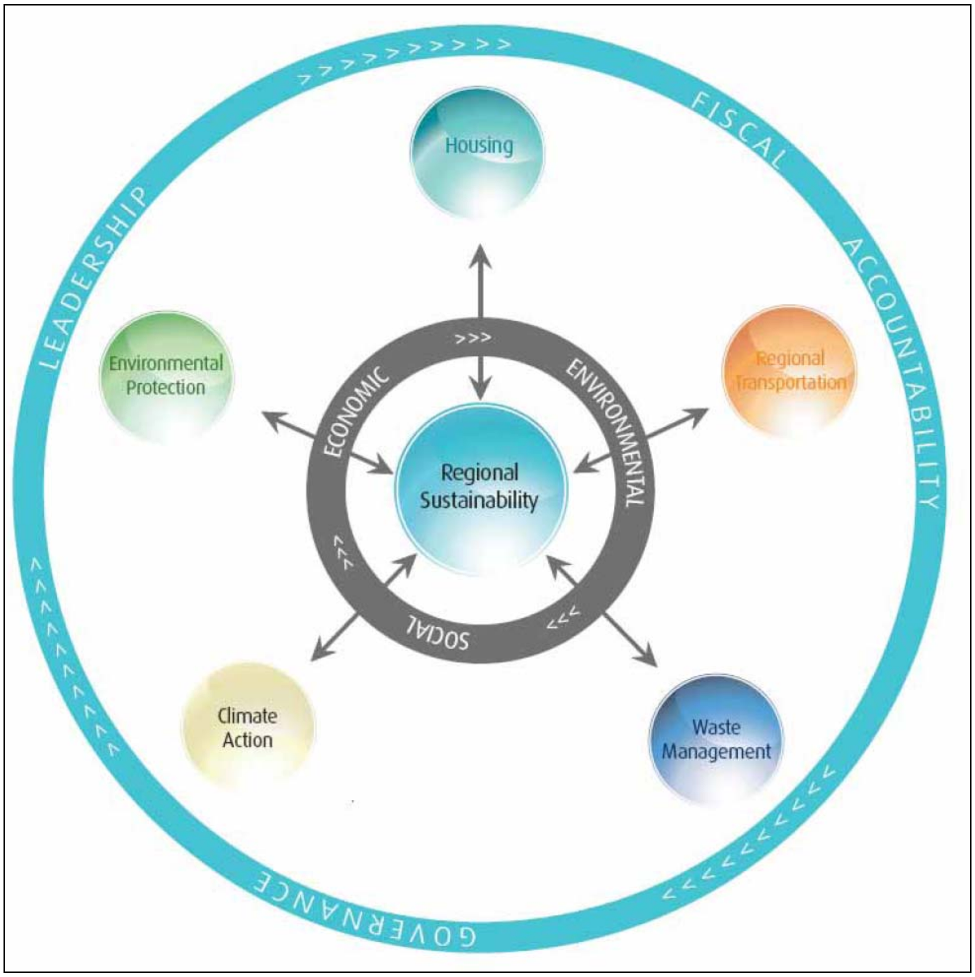

Figure 9: The Victoria CRD Strategic Plan for the years 2009 – 2011 (Capital Regional District, 2009).

The *CRD*'s water supply areas consists of the land and the watershed regions that are 98% owned by the *CRD* in the Sooke, Goldstream, Council, Charters and Leech River watersheds areas. The total area of land that is within the Sooke, Goldstream, Council and Charters water supply areas is equal to approximately 11,025 hectares or 27,242 acres. Of this area, the Sooke Reservoir's catchment area consists of 6,720 hectares or 16,605 acres. Below is an aerial photograph of the Humpback PRV (Figure 10).

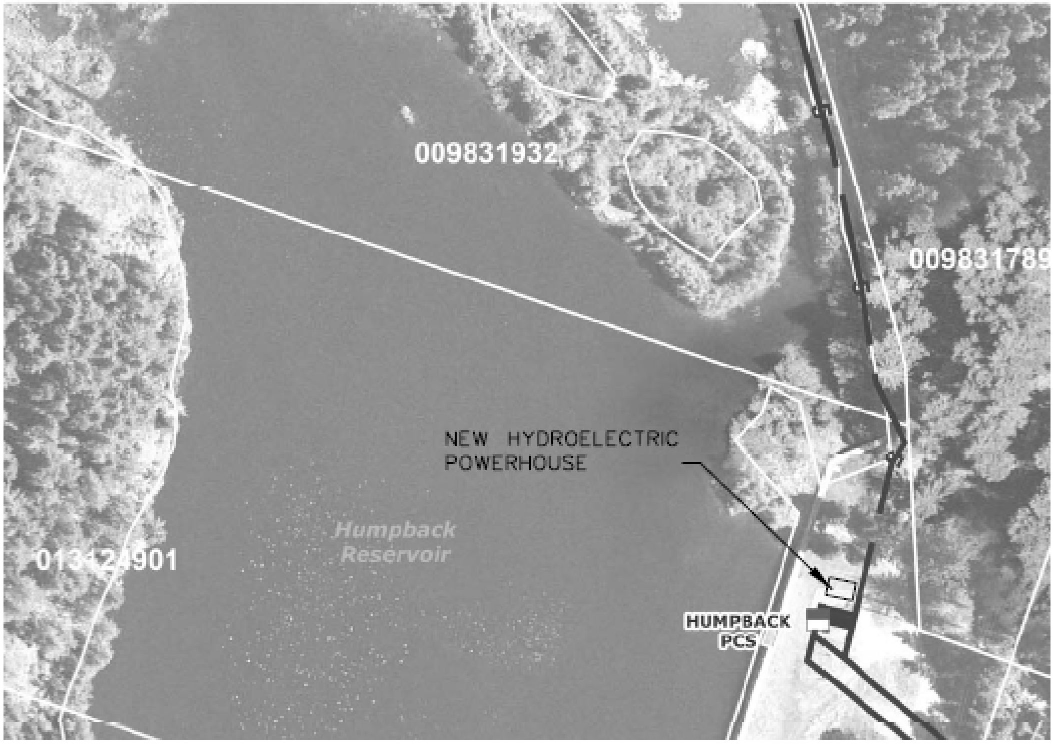

Figure 10: Arial photograph of the Humpback Reservoir and PRV, image courtesy of the CRD (Capital Regional District, 2008).

The Sooke Reservoir has been actively used since 1915 and is the largest reservoir in the *CRD's* system. It has a 100% full pool level height at 186.75 meters above sea level (m.a.s.l.). The Sooke Reservoir is the primary water supply reservoir in the Greater Victoria Water Supply Area and it provides about 90% of the total water storage, and almost 100% of the water used by the area's residents. The Sooke Dam has been modified and enlarged in its almost 100 years of use, and now stands 20 meters (66 feet) high, 530 meters (1,740 feet) long, and has a spillway located at 186.75 m.a.s.l. When the Sooke Reservoir is at its maximum size, it extends 8.3 kilometers (5.1 miles) in length, 1.6 kilometers (1 mile) in width, and has a maximum depth of 75 meters (246 feet). The total maximum volume of the Sooke Reservoir is 160.32 million cubic meters (35.3 billion gallons), of which 92.7 million cubic meters (20.4 billion gallons) are useable for water supply and potentially for electricity generation. When the Sooke Reservoir is at its maximum water level, the depth of the water above the intake is about 20 meters (66 feet). During the winter months (the rainy season), the inflow from precipitation to the Sooke Reservoir greatly exceeds the outflow for water usage or supply. This relationship begins to level off in the spring months of March or April, and after that the reservoir levels being to decrease in volume due to the greater amount of water usage than input. This rate of decline is a directly related to the amount of water use and precipitation. These seasonal variations in water usage and precipitation can result in fluctuations of up to 6 meters (20 feet) in the level of Sooke Reservoir as measured in meters above sea level (m.a.s.l.).

The Sooke Reservoir is connected to the Humpback Pressure Reducing Facility (PRF) by a network of plumbing and treatment plants. The Kapoor Tunnel (Figure 12) is the major path that water uses to move from the Sooke Reservoir to the Japan Gulch Ultraviolet Treatment Plant, which is found in front of the Humpback PRF. The Kapoor Tunnel is an 8.8 kilometers (5.5 miles) long circular tunnel that was created by a tunnel boring machine (TBM), and has a diameter of 2.3 meters (7.5 feet). A head tank is connected to the Kapoor Tunnel (Figure 11) and is used to maintain a constant water pressure.

Figure 11: The Kapoor Tunnel, image from Wikipedia (Wikipedia, 2010).

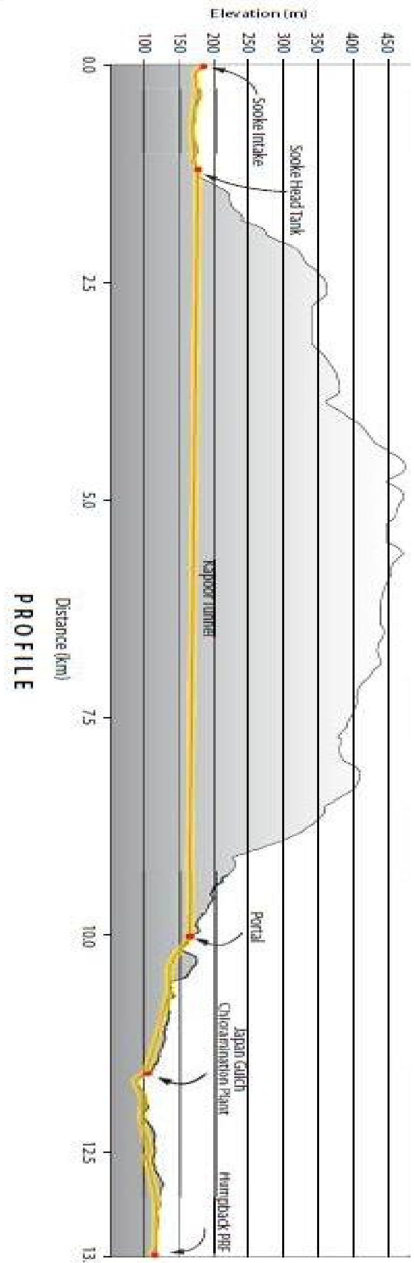

Figure 12: Profile of the Kapoor Tunnel, image courtesy of the Victoria CRD (Capital Regional District, 2008).

Water in the *CRD's* system is disinfected using ultraviolet light, followed by chlorine, and then ammonia is added to form chloramine which provides a residual disinfectant in the waterways. This treatment process provides protection against biological contaminants, bacteria, viruses, and parasites. The primary water treatment plant is located at Japan Gulch, with an alternate treatment plant at Charters River. It should be noted that the Charters River plant will be replaced by a new treatment plant off of the Sooke River Road, and this new plant is currently under construction. Below is map with the overview of the Sooke Reservoir and surrounding area (Figure 13).

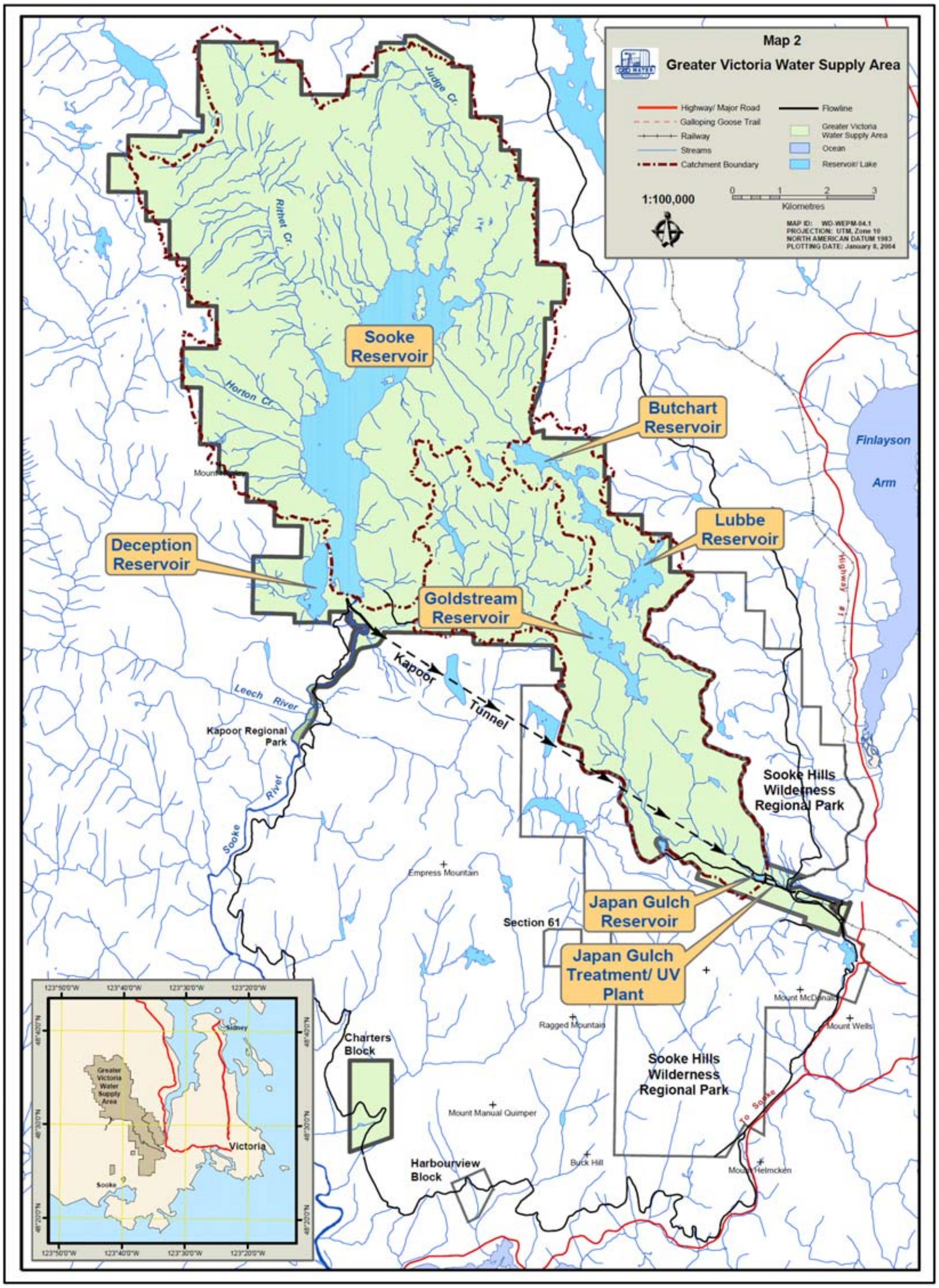

Figure 13: The Sooke Reservoir and surrounding areas. Map provided by the Victoria CRD Water (Capital Regional District, 2010).

It has been estimated by the *CRD* that water from the Leech River watershed area will be needed to supplement the water in the Sooke Reservoir due to population growth that may occur over the next 25 to 50 years. The water from the Leech River area will be brought to the Sooke Reservoir via a diversion tunnel that was constructed in the 1980's. It should be noted that the inlets and outlets of this diversion tunnel have yet to be constructed.

3.0) ANALYSIS OF FLOW AND PRESSURE:

3.1) STATISTICAL ANALYSES AND CLEANSING

All raw data was provided by the Victoria *CRD*.

Continuous hourly data was recorded from 2004 through the completion of 2009, except during equipment malfunction, or if the monitoring equipment was taken offline.

Pressure data was recorded in pascal (Pa) by a monitoring gauge at the inlet to the UV Treatment Plant, and an outlet monitoring gauge was installed at the outlet of the Humpback PRF. The value in pascal (Pa) was converted to meters of head (m) by the *CRD* in an Excel Spreadsheet using water at a temperature of 4° Celsius. Total flow was reported in liters per second (L/s) and was recorded by two sensors in two different size pipes. The two sensors are: 1) 1050mm *Ultrasonic* and a 2) 975mm *Venturi*. The total flow was used as the sum of the flow recorded on each sensor at each hourly interval. All data was taken and recorded on the hour, in 1 hour intervals.

Monthly averages, yearly- monthly averages, and yearly- daily averages were calculated for both inlet flow pressure head (m) and for total flow (L/s). The monthly total flow values were plotted against the inlet flow pressure, and a regression trend line was fitted to the relationship. Flow values (L/s) were plotted again during the course of the year to show how flow rates changed within the year. Maximum as well as minimum flow values were calculated on an hourly basis and plotted.

Histograms of inlet pressure (m) and total flow (L/s) were created to show distribution and distribution type. Total flow (L/s) versus inlet pressure (m) was graphed. Trends in the data were observed and the data was cleaned. A 1-way ANOVA (between inlet pressure and total flow) test was run, with a null hypothesis that the data had no significant differences in population means. A linear regression line was fit to the dataset. Outliers were removed from the linear regression model to tighten the R^2 value. Reasons or explanations were provided if data was omitted from an analysis procedure; these were usually provided by the *CRD*. A time not exceeding graph was created for both the total flow rate (L/s) and the inlet pressure (m) for all data sets.

When significant data was not included in the analyzed data set, a percentage of omitted and used data was calculated. Average monthly total flow (L/s) and inlet pressure (m) values were calculated.

An average outlet pressure head (m) was determined and subtracted from the inlet pressure (m) head to give a usable pressure head (m) value.

3.2) 2004 DATA:

- Data from the first 10 days of January were omitted. The first 9 days have no value, and Day 10 value was skipped
- Data from January 15th at 12:00pm to January 29th at 12:00pm were not used
- A total of 337 data entries with values were not used in the study. This constitutes 3.8% of the total collected entries
- There are a total of 8437 data entries that were part of the analysis
- Very near to 96.2% of all recorded entries were used
- No notes on the data collection were provided by the Victoria *CRD*
- Reason author chose not to use data: data not included due to extremely low inlet pressure head values

The figure below (Figure 14) shows all hourly inlet pressure heads (m) and total flow (L/s) recorded in 2004. This figure shows a good example of data that was omitted from the analysis, as only the common flow scheme was used.

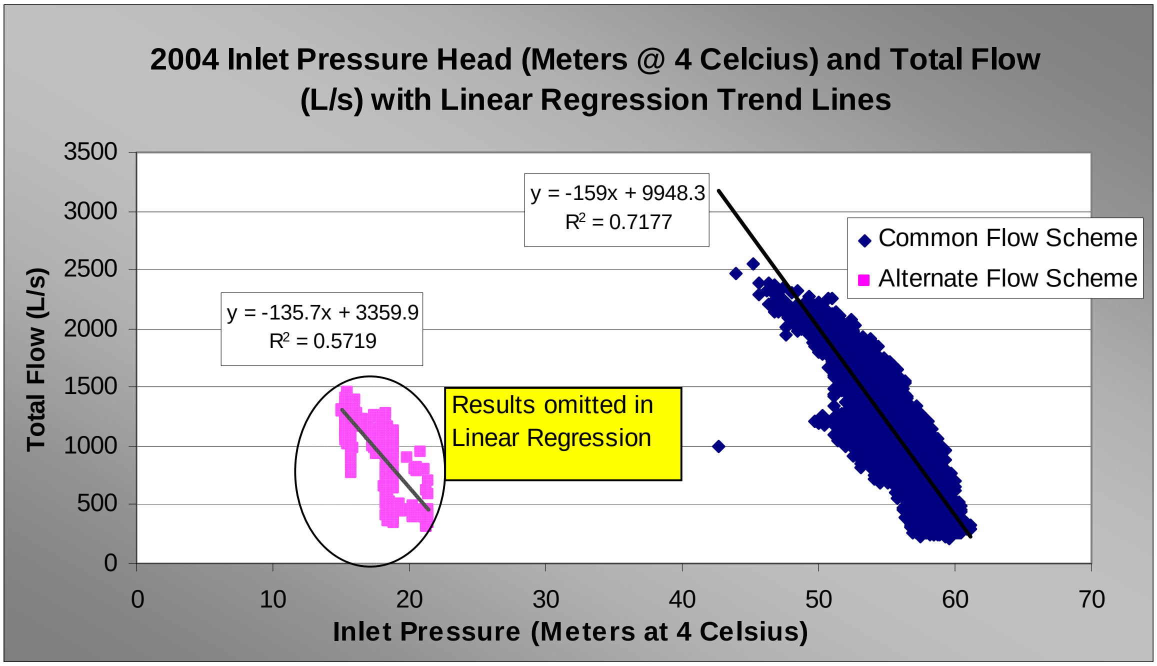

Figure 14: 2004 hourly inlet pressure head and total flow (L/s). Note the two dominant trending data groups.

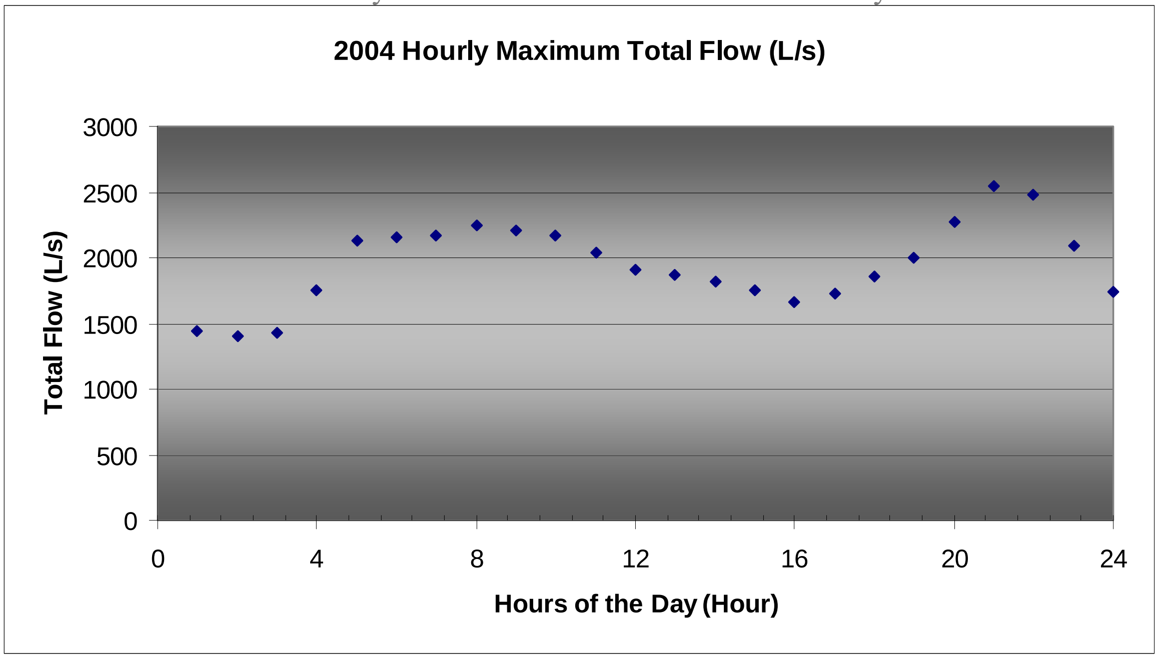

Figure 15: 2004 maximum hourly total flow (L/s) values. Data was taken over the course of the entire year and sorted into a 24 hours interval.

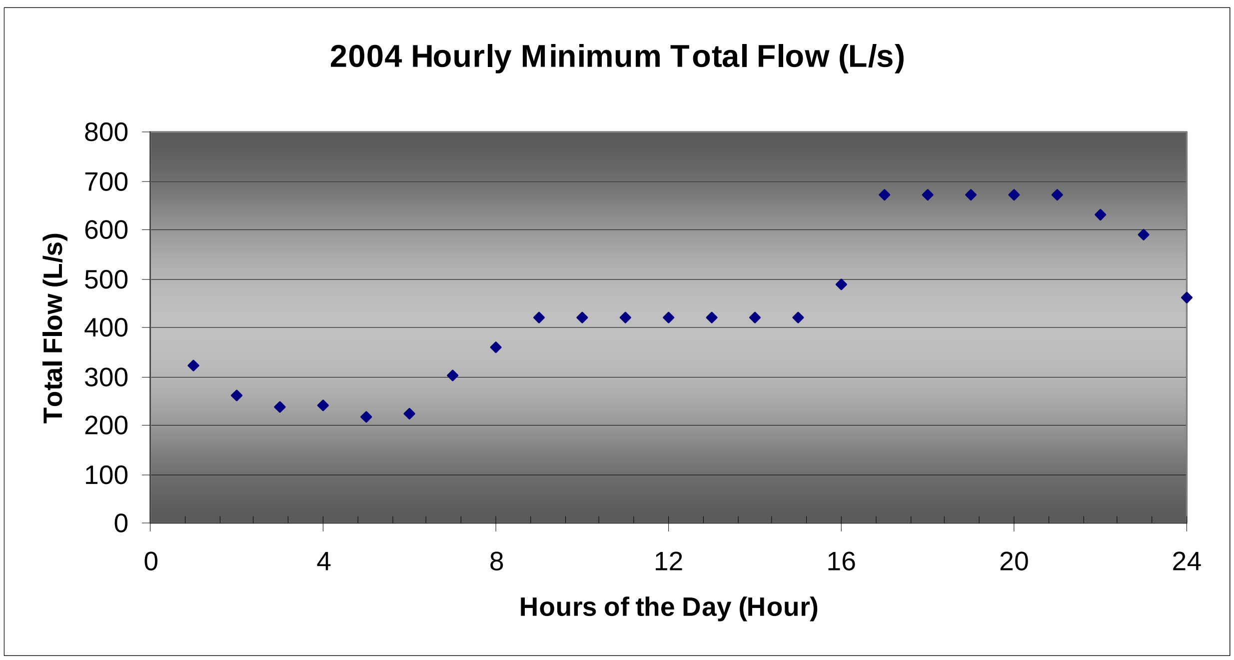

Figure 16: 2004 minimum hourly total flow (L/s) values. Data was taken over the course of the entire year and sorted into a 24 hours interval.

The two above figures and the corresponding two tables below, illustrate an example of the maximum observed total flow range (L/s) (Figure 15 and Figure 16) and inlet pressure head range (m) (Table 2 and Table 3) in 2004.

Table 2: 2004 maximum hourly inlet pressure head (m) values. Data was taken over the course of the entire year and sorted into a 24 hours interval.

2004 Hourly Maximum Pressure Head (Meters @ 4 Celcius)		
Hours of the Day (Hour)	Inlet Pressure Head (Meters @ 4 Celcius)	Time (date and hour)
1	60.42	Jan 5 2004 1:00AM
2	60.42	Jan 5 2004 2:00AM
3	61.17	Feb 21 2004 3:00AM
4	61.17	Feb 21 2004 4:00AM
5	60.86	Jan 13 2004 5:00AM
6	60.42	Dec 10 2004 6:00AM
7	60.20	Feb 22 2004 7:00AM
8	59.59	Jan 11 2004 8:00AM
9	59.54	Dec 11 2004 9:00AM
10	59.54	Dec 11 2004 10:00AM
11	59.54	Dec 11 2004 11:00AM
12	59.54	Dec 11 2004 12:00PM
13	59.54	Dec 11 2004 1:00PM
14	59.54	Dec 11 2004 2:00PM
15	59.54	Dec 11 2004 3:00PM
16	59.54	Dec 11 2004 4:00PM
17	59.72	Jan 5 2004 5:00PM
18	58.97	Mar 15 2004 6:00PM
19	59.28	Jan 1 2004 7:00PM
20	58.84	Jan 2 2004 8:00PM
21	59.19	Jan 11 2004 9:00PM
22	59.30	Jan 3 2004 10:00PM
23	59.41	Jan 3 2004 11:00PM
24	59.41	Jan 4 2004 12:00AM

Table 3: 2004 minimum hourly inlet pressure head (m) values. Data was taken over the course of the entire year and sorted into a 24 hours interval

2004 Hourly Minimum Pressure Head (Meters @ 4 Celcius)		
Hours of the Day (Hour)	Inlet Pressure Head (Meters @ 4 Celcius)	Time (date and hour)
1	15.82	Jan 29 2004 1:00AM
2	15.82	Jan 29 2004 2:00AM
3	15.82	Jan 29 2004 3:00AM
4	15.82	Jan 29 2004 4:00AM
5	15.82	Jan 29 2004 5:00AM
6	15.82	Jan 29 2004 6:00AM
7	15.82	Jan 29 2004 7:00AM
8	15.83	Jan 29 2004 8:00AM
9	15.12	Jan 27 2004 9:00AM
10	15.12	Jan 27 2004 10:00AM
11	15.38	Jan 20 2004 11:00AM
12	15.34	Jan 25 2004 12:00PM
13	15.34	Jan 25 2004 1:00PM
14	15.34	Jan 18 2004 2:00PM
15	15.34	Jan 18 2004 3:00PM
16	15.34	Jan 18 2004 4:00PM
17	15.34	Jan 18 2004 5:00PM
18	15.34	Jan 18 2004 6:00PM
19	15.34	Jan 18 2004 7:00PM
20	15.34	Jan 18 2004 8:00PM
21	15.34	Jan 18 2004 9:00PM
22	15.82	Jan 28 2004 10:00PM
23	15.82	Jan 28 2004 11:00PM
24	15.82	Jan 29 2004 12:00AM

3.3) 2005 DATA:

- Data from September 27th at 10:00pm to September 28th at 4:00am was not used
- Data from October 13th at 8:00pm to October 14th at 3:00am was not used
- A total of 15 data entries with values were not used in the study. This constitutes 0.2% of the total collected entries
- There are a total of 8745 data entries that were part of the analysis
- Very near to 99.8% of all recorded entries were used
- No notes on the data collection were provided by the Victoria *CRD*

The two tables below (Table 4 and Table 5) show all hourly inlet pressure heads (m) and total flow (L/s) recorded in 2005. These tables show a good example of the data that was used in the analyses. The 2005 averages and variances for the inlet pressure head (m) and total flow (L/s) are found below (Table 4).

Table 4: Part of the results of an Excel ANOVA analysis run on the 2005 data set.

Anova: Single Factor				
SUMMARY				
Groups	*Count*	*Sum*	*Average*	*Variance*
Inlet Pressure Head (Meters @ 4 Celsius)	8760	490041.5	55.94080848	6.789204
Total Flow (L/s)	8760	8701176	993.2849746	101030.7

Table 5: Part of the working values and results of an Excel ANOVA analysis run on the 2005 data set.

ANOVA						
Source of Variation	*SS*	*df*	*MS*	*F*	*P-value*	*F crit*
Between Groups	3848329696	1	3848329696	76176.3	0	3.84198949
Within Groups	884987104.2	17518	50518.72955			
Total	4733316800	17519				

Histograms were also part of the analysis. Below (Figure 17 and Figure 18) are the 2005 data distributions for total flow (L/s) and inlet pressure heads (m).

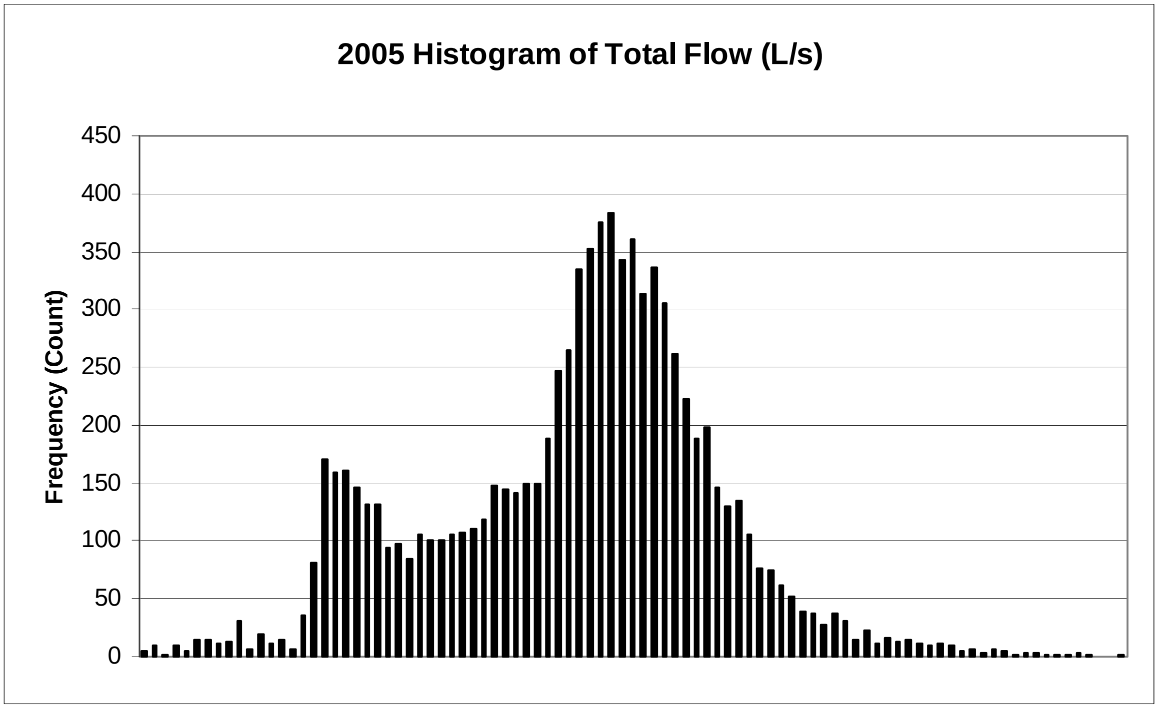

Figure 17: 2005 histogram of total flows (L/s).

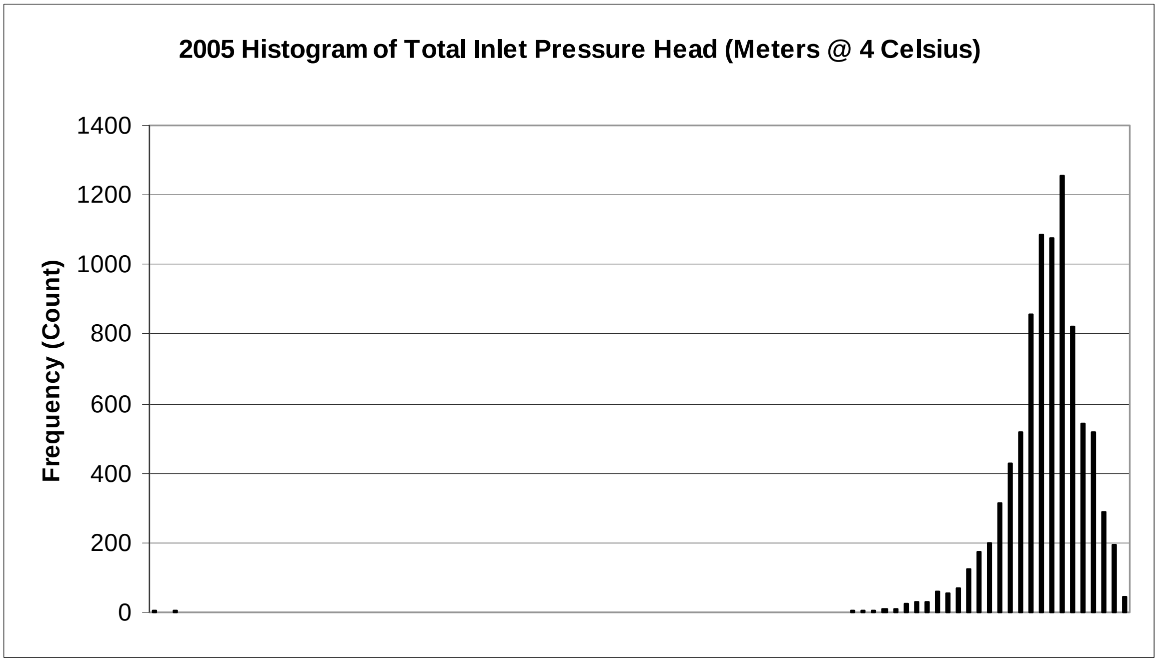

Figure 18: 2005 histogram of inlet pressure heads (m).

3.4) 2006 DATA:

- No data recorded from March 31st at 12:00am (24:00) to April 2nd at 12:00am (24:00). Continuous data recording occurred again after April 2nd at 12:00am (April 3rd at 0:00am)
- No data recorded from September 30th at 12:00am (24:00) to October 31st at 12:00am (24:00). Continuous data recording occurred again on November 1st after 12:00am (24:00) (November 1st at 1:00am)

Notes on 2006 Missed and Not Used Data:

The following data points were not used:

- January 20th, 2006 at 9:00am to and including February 7th at 10:00am
- February 27th, 2006 at 10:00am to and including March 1st at 2:00pm (14:00)
- March 20th, 2006 at 10:00am to and including March 24th at 7:00am
- July 12th, 2006 at 11:00pm (23:00) to and including July 26th, 2006 at 12:00pm (12:00)
- A total of 907 data entries with values were not used in the study. This constitutes 11.4% of the total collected entries
- There are a total of 7061 data entries that were part of the analysis
- Very near to 88.6% of all recorded entries were used
- No data was recorded for two intervals during the course of the year

The comments were compiled from the data provided by the *CRD* and presented below (Table 6).

Table 6: Comments made by the CRD on the 2006 data set. Comments provided by CRD, Water D. Robson, on July 30, 2008.

Data Anomalies		
2006 Data	Anomaly	Reason
Jan. 20 - Feb. 7	Inlet pressure low (< 50 psi)	Annual tunnel shut down period (18 days)
Feb. 27 - Mar. 1	Inlet pressure low (< 50 psi) and low flow (<100 l/s)	Unknown, unreliable data
Mar. 20 - Mar. 23	Inlet pressure low (< 50 psi) and low flow (<100 l/s)	Unknown, unreliable data
April 1 - April 2	No data available	Unknown
July 13 - July 26	Inlet pressure low (< 50 psi)	Unknown, unreliable data
Oct. 1 - Oct. 31	No data available	Unable to retrieve data

- Note: The month of October was omitted, due to no recorded data

An important concept in hydropower studies is the understanding of a percent of time exceeding graph. The two figures below (Figure 19 and Figure 20) show the 2006 values of total flow (L/s) and inlet pressure head (m) and the percent of time that the chosen values will be greater. This allows for flow (L/s) and head (m) conditions to be selected, and to see what percentage of time those conditions are exceeded. This is very relevant in determining suitable turbine runner and generation equipment sizes.

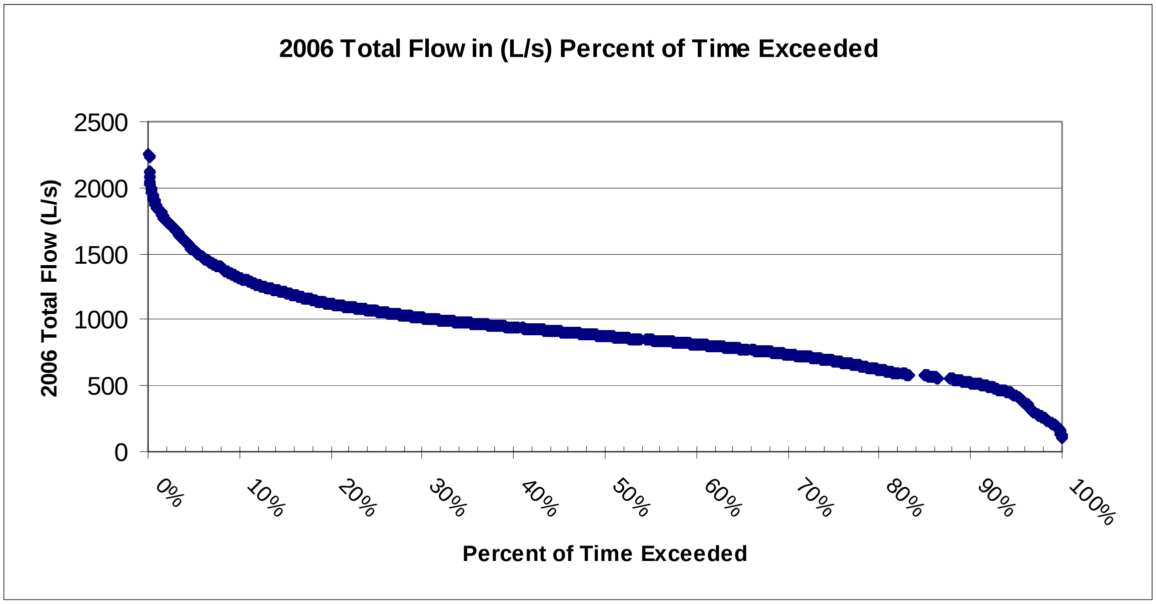

Figure 19: 2006 total flow values (L/s) and the percent of time that value is exceeded.

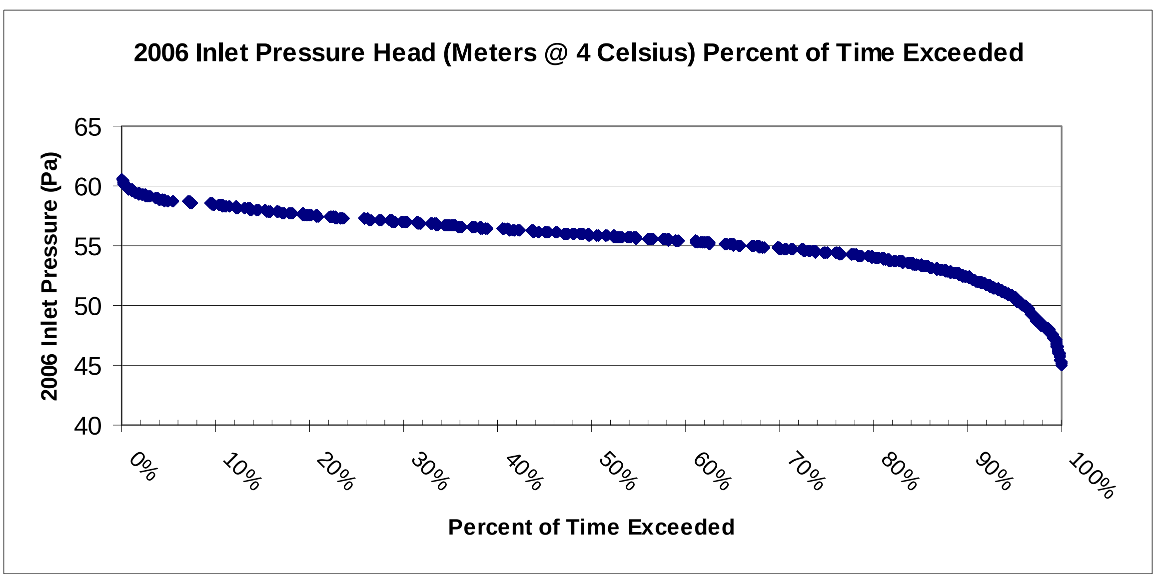

Figure 20: 2006 inlet pressure head values (m) and the percent of time that value is exceeded.

3.5) 2007 DATA:

- No data recorded from March 31st at 12:00am (24:00) to April 2nd at 12:00am (24:00). Continuous data recording occurred again after April 2nd at 12:00am (April 3rd at 0:00am)

Notes on 2007 Missed and Not Used Data:

The following data points were not used:

- January 22nd, 2007 at 1:00pm (13:00) to and including January 29th at 1:00pm (13:00)
- October 1st, 2007 at 12:00am (24:00) to and including October 13th at 7:00am
- A total of 465 data entries with values were not used in the study. This constitutes 5.3% of the total collected entries
- There are a total of 8247 data entries that were analyzed
- Very near to 94.7% of all recorded entries were used
- No data was recorded for one (1) interval during the course of the year

The following reasons for not including portions of the 2007 data set were compiled from the data provided by the *CRD* (Table 7).

Table 7: Notes on the 2007 data set.

2007 Data	Anomaly	Reason
Jan. 22 - Jan. 29	Inlet pressure low (< 50 psi)	Annual tunnel shut down period (7 days)
April 1 - April 2	No data available	Unknown
Oct. 1 - Oct. 8	Data is static	Unknown, unreliable data
Oct. 9 - Oct. 12	Inlet pressure low (< 50 psi) and low flow (<100 l/s)	Unknown, unreliable data

- The first 13 days of the month of October was omitted, due to no recorded data

The table below (

Table 8) shows the total number of points, and the corresponding percentage, of the total entries used in the 2007 data set.

The two large tables below (Table 9 and Table 10) illustrate an example of the maximum observed total flow range (L/s) in 2007.

Table 8: The number of points and percentage of total entries used in the 2007 data set.

Total points not Used:	Total points Used:
465	8247
Percentage of Data Not Used	
5.34	
Percentage of Data Used	
94.66	

Table 9: 2007 maximum hourly total flow (L/s) values. Data was taken over the course of the entire year and sorted into a 24 hours interval.

2007 Hourly Maximum Total Flow (L/s)		
Hours of the Day (Hour)	**Total Flow (L/s)**	**Time (date and hour)**
1	1509.43	Jul 11 2007 1:00AM
2	1719.40	Jul 11 2007 2:00AM
3	1847.54	Jul 12 2007 3:00AM
4	2334.73	Jul 11 2007 4:00AM
5	2381.14	Jul 12 2007 5:00AM
6	2406.42	Jul 11 2007 6:00AM
7	2418.40	Jul 11 2007 7:00AM
8	2382.46	Jul 11 2007 8:00AM
9	2265.55	Jul 5 2007 9:00AM
10	2155.13	Jul 11 2007 10:00AM
11	2083.50	Jul 7 2007 11:00AM
12	1990.17	Jul 12 2007 12:00PM
13	1994.17	Jul 11 2007 1:00PM
14	1968.81	Jul 11 2007 2:00PM
15	1822.96	Jul 11 2007 3:00PM
16	1813.93	Jun 3 2007 4:00PM
17	1890.68	Jul 14 2007 5:00PM
18	1932.38	Jun 20 2007 6:00PM
19	2402.53	Jul 11 2007 7:00PM
20	2538.96	Jul 11 2007 8:00PM
21	2503.06	Jul 11 2007 9:00PM
22	2263.40	Jul 11 2007 10:00PM
23	1868.23	Jul 15 2007 11:00PM
24	1878.09	Jul 12 2007 12:00AM

Table 10: 2007 minimum hourly total flow (L/s) values. Data was taken over the course of the entire year and sorted into a 24 hours interval.

2007 Hourly Minimum Total Flow (L/s)		
Hours of the Day (Hour)	**Total Flow (L/s)**	**Time (date and hour)**
1	358.00	Mar 26 2007 1:00AM
2	331.16	Mar 26 2007 2:00AM
3	331.16	Mar 26 2007 3:00AM
4	331.31	Mar 26 2007 4:00AM
5	365.69	Mar 25 2007 5:00AM
6	438.67	Mar 25 2007 6:00AM
7	579.15	Feb 23 2007 7:00AM
8	637.57	Oct 29 2007 8:00AM
9	470.92	Oct 29 2007 9:00AM
10	512.10	Oct 29 2007 10:00AM
11	505.78	Oct 31 2007 11:00AM
12	505.78	Oct 31 2007 12:00PM
13	931.72	Mar 21 2007 1:00PM
14	901.42	Mar 12 2007 2:00PM
15	871.79	Mar 20 2007 3:00PM
16	912.16	Jan 29 2007 4:00PM
17	910.03	Mar 22 2007 5:00PM
18	949.40	Mar 16 2007 6:00PM
19	882.41	Dec 25 2007 7:00PM
20	866.42	Feb 17 2007 8:00PM
21	823.72	Mar 24 2007 9:00PM
22	657.69	Mar 12 2007 10:00PM
23	541.43	Mar 12 2007 11:00PM
24	467.30	Mar 13 2007 12:00AM

3.6) 2008 DECEMBER DATA:

- No data recorded for January, February, March, April, May, June, July, August, September, October, and until 4:00pm (16:00) on the 30th of November
- December was recorded
- Only December was used in the analysis of 2008
- Data from December 16th at 7:00am to December 16th at 8:00am was not used
- Data from December 29th at 7:00am to December 29th at 7:00pm was not used
- A total of 16 data entries with values were not used in the study. This constitutes 2.1% of the total collected entries
- There are a total of 736 data entries that were analyzed
- Very near to 97.9% of all recorded entries were used
- No data was recorded or data is missing for one interval during the course of the year (composing of all months except December).

The following reasons for not including portions of the 2008 December data set were compiled from the data provided by the *CRD*.

Table 11: Notes on the 2008 December data set.

2008 Data	Anomaly	Reason
Jan. 1 - Aug. 10	No data available between January 1 to Aug 10	Unknown
General Comment	Existing data not analyzed for anomalies	

- No data available till November 30th at 4:00pm (16:00)
- December was continuously recorded
- Data points were omitted due to erratically lager values

The two figures below (Figure 21and Figure 22) illustrate the maximum observed inlet pressure head range (m) in December of 2008.

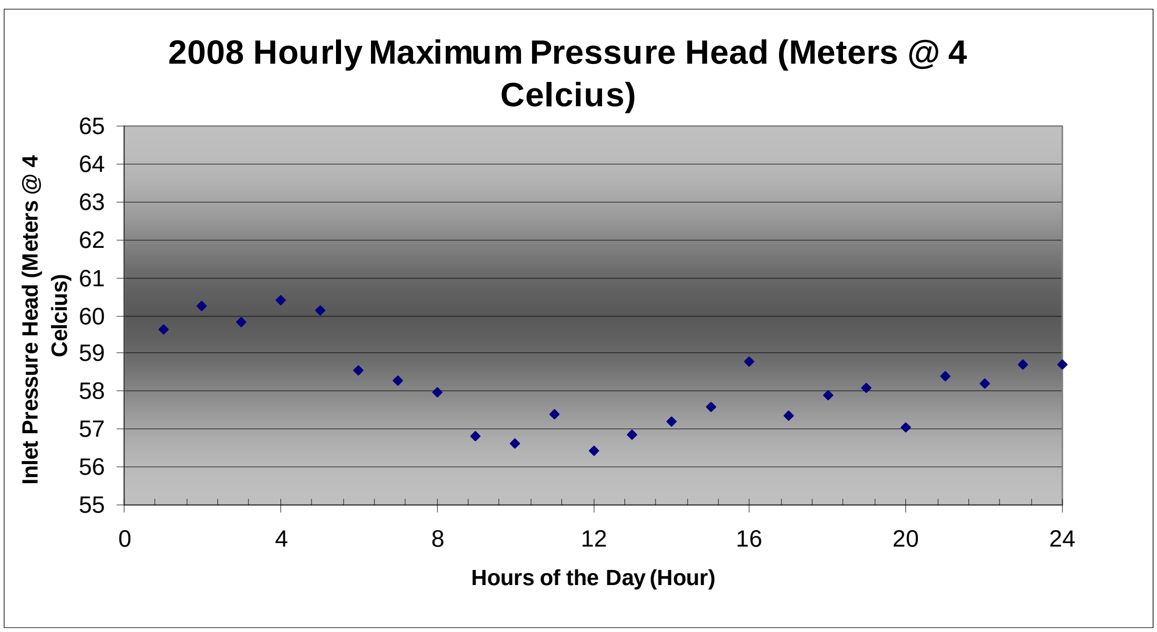

Figure 21: 2008 December maximum hourly inlet pressure head (m) values. Data was taken over the course of the entire year and sorted into a 24 hours interval.

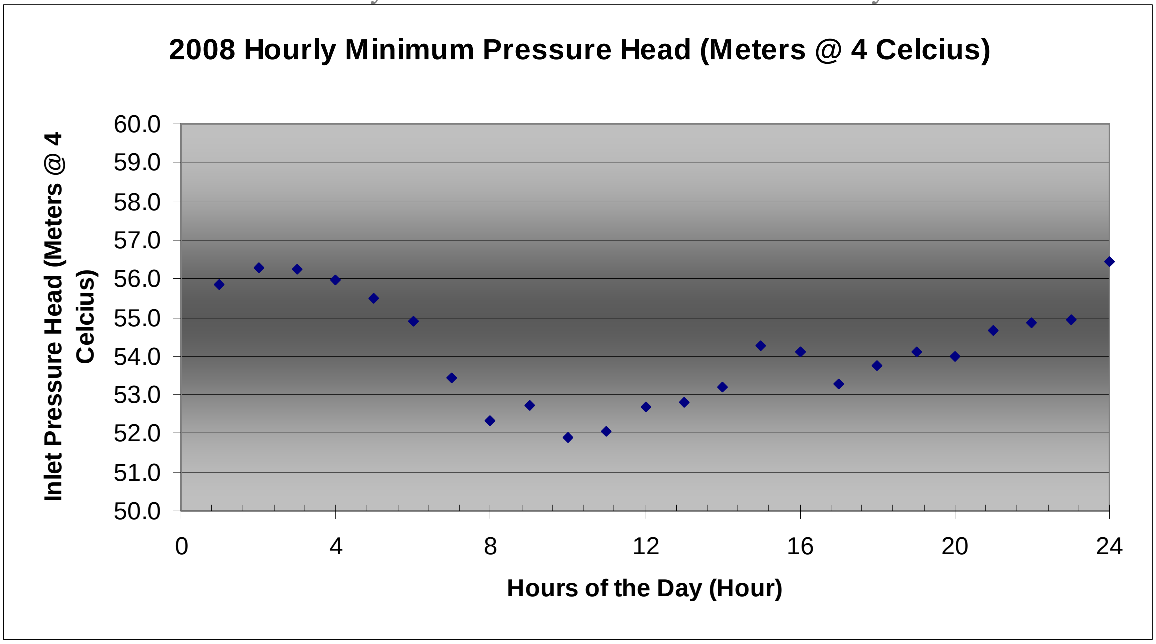

Figure 22: 2008 minimum hourly inlet pressure head (m) values. Data was taken over the course of the entire year and sorted into a 24 hours interval.

3.7) 2009 DATA:

- Continuous data was recorded for the year

Notes on 2009 Missed and Not Used Data:

The following data points were not used:

- January 12th, 2009 at 10:00am to and including February 27th at 1:00pm (13:00)
- June 2nd, 2009 at 7:00pm (19:00) to and including June 3rd at 12:00pm (12:00)
- November 30th, 2009 at 1:00pm (13:00) to and including November 30th at 2:00pm (14:00)
- December 14th, 2009 at 10:00am to and including December 18th at 10:00am
- December 19th, 2009 at 2:00am to and including December 19th at 7:00am
- December 20th, 2009 at 1:00am to and including December 20th at 6:00am
- December 21st, 2009 at 12:00am to and including December 21st at 8:00am
- In 2009 the majority of January data and almost all of the February data were omitted from analysis

- A total of 1246 data entries with values were not used in the study. This constitutes 14.2% of the total collected entries
- There are a total of 7514 data entries that were analyzed
- Very near to 85.8% of all recorded entries were used

The following reasons for not including portions of the 2009 data set were compiled from the data provided by the *CRD* (Table 12).

Table 12: Notes on the 2009 data set.

2009 Data	Anomaly	Reason
General Comment	Existing data not analyzed for anomalies	

The table below (

Table 13) shows the average useable monthly average head (m) and flow (L/s) values for the year 2009. Monthly averages were calculated from the hourly data values within the rightful month.

2009 values were entered into RETScreen as representative head (m) and flow (L/s or m^3/s) for the economic and power production analysis.

Table 13: 2009 monthly average usable pressure heads (m) and total flows (L/s).

2009 Pressure Heads (Meters @ 4 Celsius)				2009 Average Total Flow (L/s)
Month	Inlet Pressure Head (Meters @ 4 Celsius)	Outlet Pressure Head (Meters @ 4 Celsius)	Useable Pressure Head (Meters @ 4 Celsius)	Total Flow (L/s)
January	56.11	7.56	48.55	886.52
February	54.95	6.89	48.06	931.98
March	56.09	7.15	48.95	923.79
April	56.27	7.34	48.93	1024.05
May	55.05	7.64	47.41	1237.30
June	53.37	6.97	46.41	1390.89
July	52.55	6.54	46.01	1578.07
August	53.48	7.01	46.47	1610.16
September	54.98	7.10	47.87	1263.52
October	56.03	6.46	49.58	1043.68
November	56.39	6.40	50.00	946.24
December	56.61	6.48	50.13	946.43
2009 (Monthly Average)	55.16	6.96	48.20	1148.55
2009 (All Days Average)	55.10			1187.96

3.8) FORMULATING A TARGETED FLOW AND HEAD REGIME:

Simplicity and relativity good end results allowed for the use of average and linear trend lines. Average monthly inlet pressure heads (m) for water at 4° Celsius were determined for each year. Average monthly total flows (L/s) were determined for each year.

A monthly average was determined for both inlet pressure head (m) and total flow (L/s) from each of the average monthly values for all the years. For example, the average total flow (L/s) for a normal year would be the average value of all the hours within a month (for all months January through December) divided by the number of months used (or twelve in this case). This process allowed for the determining of one singular point which represented a fair average from the entire sampled year. A point was plotted from each corresponding year. The result was a set of focused (current inlet pressure head (m) and total flow (L/s)) points, one from each year studied. The figure below (Figure 23) shows a focused usable head (m) value around 48 to 50 meters, and a focused flow range (L/s) between 900 and 1200 liters per second. From the analysis of the 2003 to 2009 data, and due to a foreseeable increase in the demand of water in the future, the following values were used in the economic analysis:

Conservative Summary of Usable Head (m) and Total Flow Values (L/s or m^3/s) at the Humpback PRF:

Total Flow Rate (L/s or m^3/s): 1300 (L/s) or 1.30 (m^3/s)
Usable Head: 48.0 (m)

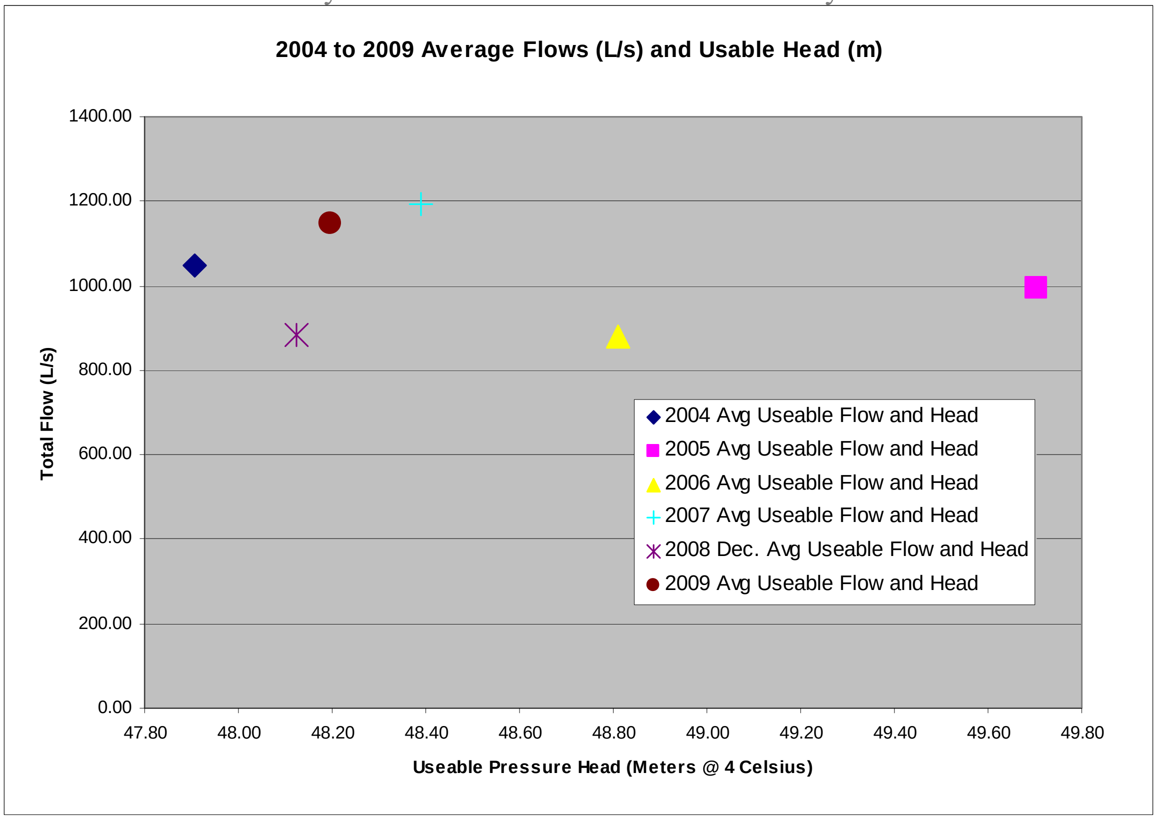

Figure 23: 2004 to 2009 average total flow (L/s) and usable pressure head (m) regime.

3.9) NOTES ABOUT THE STATISTICAL ANALYSIS:

- Small samples sizes almost always pass a normality test; this many only apply to the 2008 - December data set
- Normality tests have little to no power in telling whether or not a small sample of data comes from a Gaussian distribution
- 12:00 p.m. (12:00) refers to noon; 12:00 a.m. (24:00/0:00) refers to midnight
- With large samples, minor deviations from normality may be flagged as statistically significant, even though small deviations from a normal distribution will not affect the results of a t-test or, in this study's case, an ANOVA

4.0) KAPOOR TUNNEL AND CONNECTED WATERWAYS TO THE HUMPBACK PRF – FLOW DEVELOPMENT AND HEAD LOSSES:

The Kapoor Tunnel (Figure 24) was bored with a tunnel boring machine (TBM). It has a circular diameter of 2.3 meters (7.5 feet). It is mostly unlined and has a length of 8.8 kilometers (5.5 miles). An intake value is located at the head of the Kapoor Tunnel where it connects to the Sooke Reservoir. A head tank is located nearby, which is open to the atmosphere, and is at an elevation of 169 m.a.s.l. The tunnel passes through a package of geology that is assumed to consist of mostly fractured and unfractured basalt. The surface of this tunnel is assumed to be smooth.

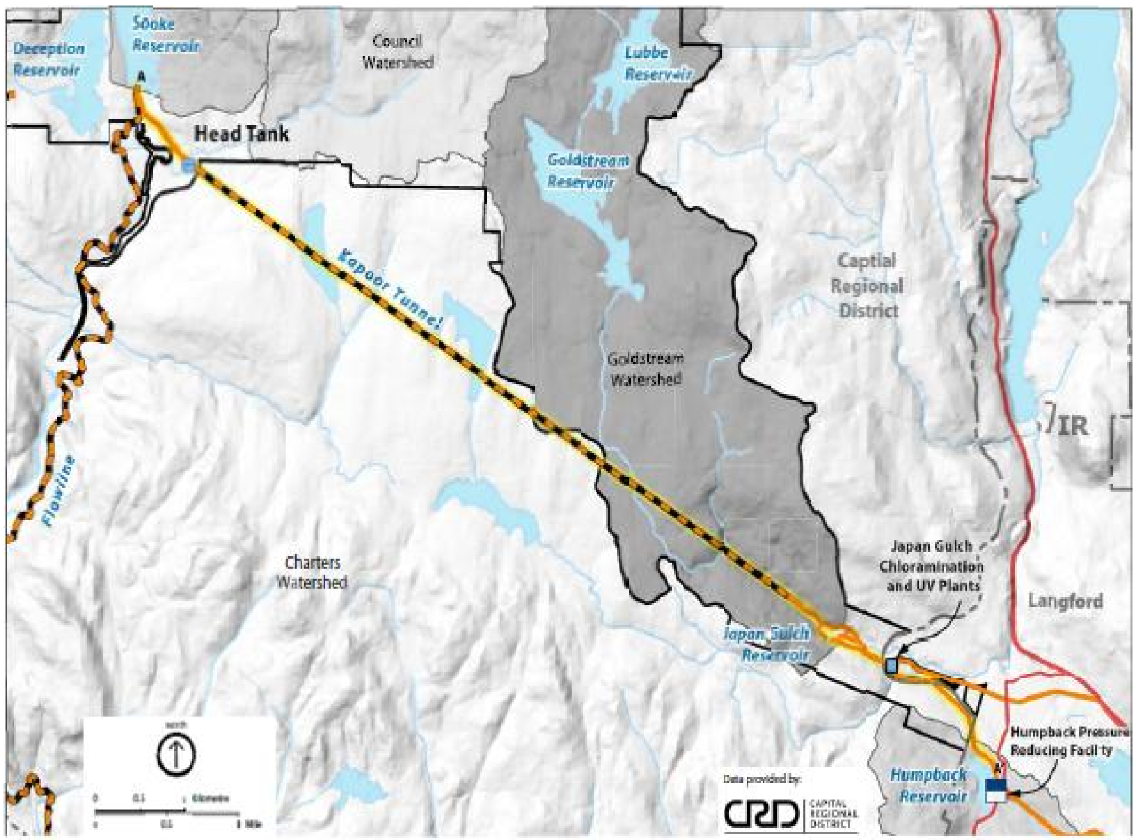

Figure 24: System overview of the flow path of water through the Sooke Reservoir, Head Tank, Kapoor Tunnel, Japan Gulch Chloramination and UV Plants, as well as the Humpback Pressure Reducing Facility. Figure courtesy of the CRD (Capital Regional District, 2010).

This tunnel is connected to a 1.5 kilometer (0.9 mile) long steel water main that has a diameter 1.5 meters (4.9 feet). This steel water main is connected to another 1.5 kilometer (0.9 mile) long water main with a similar diameter of 1.5 meters (4.9 feet). It is assumed that 2 - 90 degree bends (90°) are included in the flow path, with one bend being soft or smooth, and the other being sharp. An intake value is assumed to be at the entrance to the Chloramination and Ultra Violet (UV) treatment plants. The plants run for a length of about 200 meters, and then the treated water exits the UV plant and travels down a 1.5 kilometer (.9 mile) long steel pipe with a 1.5 meter (4.9 feet) diameter until the Humpback PRF. It is at this junction that the proposed turbine would be placed, just before the Humpback PRF. It should be noted that values and definition used below were provided by the *Engineering Toolbox* (Engineering Toolbox, 2010)

The following questions will be studied, notes marked:

- What type of flow conditions exist in the headrace (Kapoor) tunnel; is it turbulent or laminar?
- How far from the intake does the flow become fully developed (uniform)?
- What is the head loss in the waterways due to the friction (under low flow and high flow conditions)?
- The flow conditions were defined from the data set analyses
- Note: a condition of 5° Celsius was used for the calculations
- Note: a surge analysis was not studied in this thesis. This leads to two concepts that should be studied in the future: 1) How to make the PRF a backup control system of the waterways and 2) How the PRV could be used in a surge protection manner to prevent water hammer effects on the waterways

4.1) KAPOOR TUNNEL AND WATERWAYS - FLOW CONDITIOS AND DEVELOPMENT LENGTH:

Flow Conditions:

Low Flow Conditions: 125 (L/s)

High Flow Conditions: 2400 (L/s)

Headloss is due to (1) Friction Losses in the waterways (h_f) and (2) Frictional Losses due to singular features (h_k).

Darcy - Weisbach Equations for headloss (m):

(1): $h_f = f\left(\frac{L}{D_H}\frac{u^2}{2g}\right)$ (2): $h_k = K\left(\frac{u^2}{2g}\right)$

The total headloss (H_L) (m) is the sum of 1 and 2:

(3): $H_L = h_f + h_k$

h_f: is the head loss (m) due to the friction of the water on the surface of the pipe or tunnel

L : is the length of the pipe

D_H : is the hydraulic diameter, if the waterway is circular the pipe diameter (D) is used, if otherwise:

$D_H = \frac{4A}{P}$. A : is the crossectional area, and P: is the wetter perimeter of the cross section.

u : is the average fluid flow velocity, $u = \frac{Q}{A}$

g : is the local acceleration

f : is a dimensionless coefficient, known as the Darcy friction factor.

The Colebrook equation below (6) or (6a) was used to find f.

What type of flow conditions exist in the headrace (Kapoor) tunnel; is it turbulent or laminar?

Q : is the flow rate ($\frac{m^3}{s}$); for the low flow case, Q = 0.125 ($\frac{m^3}{s}$) or 125 (L/s)

1000L of water = 1 m^3 of water.

A : is the area of tunnel (m^2), $A = \pi r^2$, where r = the tunnel radius, and π = 3.1415...

υ_{5^oc} : is the kinematic viscosity of water at 5^o celcius, and has a value of $1.51*10^{-6}$ ($\frac{m^2}{s}$).

R_e : is the Reyonds Number and is determined by:

(4) $R_e = \frac{uD}{\upsilon_{5^oc}}$; for the Kapoor Tunnel under low flow conditions ; $R_e = \frac{D}{\upsilon_{5^oc}}$

Under low flow conditions: u = 0.125 (m/s), D = 2.3 (m), $\upsilon_{5^oc} = 1.51*10^{-6}$ ($\frac{m^2}{s}$)

R_e (low flow conditons) = 190397.351 >> 3000 (condition defining turbulent flow, R_e > 3000)

R_e (high flow conditons) = 219966.52 >> 3000

Turbulent flow occurs under both conditions.

How far from the intake does the flow become fully developed (uniform)?

L_e : Entrance Lenght, Lenght to develop (m) for turbulent flow.

(5) $\frac{L_e}{D} \approx 4.4(R_e)^{\left(\frac{1}{6}\right)}$

L_e (low flow conditions) = 76.75 meters

L_e (high flow conditions) = 78.63 meters

4.2) KAPOOR TUNNEL AND WATERWAYS- HEAD LOSSES DUE TO FRICTION:

What are the head losses (m) in the waterways due to the friction: (under low flow and high flow conditions)?

Low flow conditions (125 L/s, or .125 m^3/s) :

(6) : Colebrook Equation: $f = \dfrac{0.25}{\left[\log\left(\left(\dfrac{K_s / D}{3.7}\right)+\left(\dfrac{2.51}{R_e\sqrt{f}}\right)\right)\right]^2}$;

In the case of turbulent flow when R_e is large the formula becomes

(6a): $f = \dfrac{0.25}{\left[\log\left(\dfrac{K_s / D}{3.7}\right)\right]^2}$

K_s values; Basalt: 0.008 meters, Steel: 0.000046 meters.

Frictional loss factor for basalt (D = 2.3 m): $f_{Basalt} = 0.027$

Frictional loss factor for steel (D = 1.5 m) : $f_{Steel} = 0.010$

Once a f values is determined, we can determine the head loss due to friction in the pipes

from equation (1) : (1): $h_f = f\left(\dfrac{L}{D_H}\dfrac{u^2}{2g}\right)$

Kapoor Tunnel frictional head loss (m):

Low flow conditions, $f_{Basalt} = 0.027$, L=8800 (m), $D_H = 2.3$ (m) u = 0.007 (m/s), g = 9.81 (m/s^2);

High flow conditions, $f_{Basalt} = 0.027$, L=8800 (m), $D_H = 2.3$ (m) u = 0.144 (m/s), g = 9.81 (m/s^2);

$h_{f\,\text{Kapoor Low Flow}}$ = Low flow head loss conditions in the Kapoor Tunnel $\approx$ 0 meters

$h_{f\,\text{Kapoor High Flow}}$ = High flow head loss conditions in the Kapoor Tunnel = 0.12 meters

Steel Water Main frictional head losses (m):

There are a total of 3 lenght of steel water main, all three at 1.5 km in length and have a diameter of 1.5 m. This makes for a total lenght of 4.5 km of steel pipe, D = 1.5 m.

Steel Water Main frictional head losses (m):

Low flow conditions, $f_{Steel} = 0.000046$, L=4500 (m), $D_H = 1.5$ (m) u = 0.018 (m/s), g = 9.81 (m/s^2);

High flow conditions, $f_{Steel} = 0.000046$, L=4500 (m), $D_H = 1.5$ (m) u = 0.340 (m/s), g = 9.81 (m/s^2);

$h_{f\,\text{Steel Water Main Low Flow}}$ = Low flow head loss conditions in the 3 steel main waterways $\approx$ 0 meters

$h_{f\,\text{Steel Water Main High Flow}}$ = High flow head loss conditions in the 3 steel main waterways $\approx$ 0 meters

Therefore, the total headloss due to friction in the waterwater from the Kapoor Tunnel inlet to the Humpack PRF (excluding the losses in the treatment plants) are estimated

to be: $h_{f\,\text{Low Flow}} \approx 0.0$ meters - $h_{f\,\text{High Flow}} \approx 0.12$ meters

What are the frictional head losses due to singular features?

Equation 2, was used to determine this:

(2): $h_k = K\left(\frac{u^2}{2g}\right)$

To simplify the analysis the following points for singular losses are used:

Low flow conditions, u = 0.007 (m/s), High flow conditons, u = 0.144 (m/s)

- Fully Opened Intake Gate Valve D = 2.3 m, K = 0.5

$h_{k\,\text{Low Flow Intake Gate}} \approx 0$ meters; $h_{k\,\text{High Flow Intake Gate}} \approx 0.5$ meters

Low flow conditions, u = 0.018 (m/s), High flow conditons, u = 0.34 (m/s)

- 1 90° Bend (Sharp) D = 1.5 m, K = 1.1

$h_{k\,\text{Low Flow 90° Sharp Bend}} \approx 0$ meters; $h_{k\,\text{High Flow 90° Sharp Bend}} \approx 0.0$ meters

- 1 90° Bend (Soft), K = 0.2

$h_{k\,\text{Low Flow 90° Soft Bend}} \approx 0$ meters; $h_{k\,\text{High Flow 90° Soft Bend}} \approx 0.0$ meters

- 1 Intake Valve at The Entrance to the Treatment Plants, K = 0.2

$h_{k\,\text{Low Flow Intake Plant Valve}} \approx 0$ meters; $h_{k\,\text{High Flow Intake Plant Value}} \approx 0.0$ meters

Summary of Singular Losses (sum of all singular loss events)

Low Flow Conditions: ≈ 0 meters

High Flow Conditions: ≈ 0.5 meters

In Summary the net head losses (m) from the Kapoor Tunnel intake to the PRF (not including the treatment plants) are:

Close to 0 meters under low flow condtions

Approximantly 1 meter under high flow conditions

4.3) HUMPBACK PRF – POTENTIAL USABLE HEAD FOR POWER PRODUCTION:

The amount of usable head can be determined by equation (7):

(7): $h_R = h_T + h_{tur} + h_L$

h_R : is the height (m) of the reservoir

h_T : is the heigh (m) of the tail race or tail reservoir

h_{tur} : is the net head (m) useable by the turbine

h_L : are head losses (m); used as a negative height

As is shown above in equation 7, the initial reservoir height has to equal the height of the tail race, plus all the head losses that the water accrued along its path to the turbine, and then the rest can be used for power generation. In the case of the Sooke Reservoir, the head tank opens to the atmosphere at an approximate elevation of 169 m.a.s.l. As Planit Management and Stantec Consulting (2004) showed, the current center line for the Humpback PRF is at 109.6 m.a.s.l. If this point is used as an approximate value for the centerline of a proposed turbine runner, 60 meters of head would be available under the condition of no head losses.

As was observed when the statistical analysis was performed, the approximated average Humpback PRF outlet pressure head was around 7 meters; this value is much larger than originally accredited for by Planit Management and Stantec Consulting (2004) which estimates an average of 4 meters of outlet pressure head. From a simplistic calculation of head losses due to friction and singular events totaling around 1 meter (depending on flow conditions), this value needs to be reduced from the total available pressure head. This would imply that between the treatment plant processes and a possible turbine, a net usable head of up to 50-52 meters would be available. Head losses at the treatment plant vary under different flow regimes. It is estimated that the treatment plants uses an average of 8 meters of head. However, it is also estimated that 4 meters of head can be taken off of the outlet pressure and with little to no effect on the system. This would result in 4 more meters of net head loss, and thus result in the estimated usable head (m) for power production at Humpback PRV to be 48 meters. This value of 48 meters of usable head was entered into RETScreen for the economic and hydro potential analysis.

Below is a summary of these finding:

The amount of usable head for the Victoria - CRD:

$h_R = h_T + h_{tur} + h_L$

h_R : is the height (m) of the reservoir Sooke Reservoir head tank (169 m)

h_T : is the heigh (m) of the tail race (109.6 + 7 meters outlet pressure m)

h_{tur} : is the net head (m) useable by the turbine

h_L : is used as a negative height (m), Head Losses (1 m)

Re-arranging and sloving for h_{tur} results in equation 8:

(8): $h_{tur} = h_R - h_T - h_L$

$h_{tur} = 169(m) - 113.9(m) - 1(m); \quad h_{tur} = 54.1m$

*Note, h_{tur} is the primary pressure head that is reponsible for pushing the potable water through the treatment plants and waterways. The remaining pressure head could be used by a turbine to generate electricity.

5.0) USING RETSCREEN4 - THE ECONOMIC AND HYDROELECTRIC GENERATING POTENTIAL OF THE HUMBACK PVR:

The economic analysis was done using the software program RETScreen4 (Figure 25), a clean energy project analysis software which is provided free of charge by Natural Resources Canada (Natural Resources Canada, 2010). All economic equations and algorithms were created by *Natural Resources Canada* and used through the RETScreen4 interface. The project information outlined below was entered into the project.

Figure 25: RETScreen Banner, RETSceeen was produced by the Government of Canada.

5.1) KEY VALUES USED IN THE RETSCREEN ANALYSES:

An average *usable head of 48 meters* was used in the calculations (Figure 23). It should be noted that the average usable head values exceeded that value in each and every year from 2005-2009. This value changes over time; for example during maintenance, under flow diversion scenarios, or depending on the head losses in the treatment plants. However, for the point of this paper, a usable head of 48 meters was considered a fair conservative value for the purpose of an economic analysis.

An average *total flow of 1300 liters per second (L/s), or 1.30 cubic meters per second (m^3/s)* was used in the calculations (Figure 23) The average flow rate in 2009 was almost 1150 L/s; however, over the course of this project, it is estimated that the demand on water will increase. The value of 1300 L/s was also used by Planit Management and Stantec Consulting (2004), as they estimated that water demand will increase by about 2.3 percent per year till 2020.

BC Hydro has provided the table below (

Table 14) which shows that the increase in demand for electricity in the Victoria, B.C. area has a compound growth rate. This table shows the electricity usage per year in the Victoria Area, in Gigawatt hours (GWh), and with a rate of change in energy usage from year to year. A five year compounding electricity consumption rate in the Victoria Area, for the years 2004-2010, was found to be 1.60 percent. It is assumed that the water usage rate in the Victoria, B.C. area will mimic that of the electricity demand.

Table 14: Table provided by BC Hydro which shows a 5 year compound growth rate of 1.60% in electricity consumption in the Victoria, B.C. area.

Fiscal Year	Electricity Consuption Use(GWh)	Year to Year Growth Rate (%)
2004 -2005	2,988	
2005 - 2006	3,115	4.20%
2006 - 2007	3,213	3.10%
2007 - 2008	3,319	3.30%
2008 - 2009	3,359	1.20%
2009 - 2010	3,236	-3.70%
5 Year Compound Rate (%)		1.60%

A *GILKES* Francis turbine was incorporated into the analysis. *GILKES* was contacted with regard to the price of a relevant sized powerhouse and all of its components, including the turbine runner size, generator size, etc. In response to this request, *GILKES* responded with an estimate that was done on the Humpback PRF in 2004; see Appendix 2 (Gilkes, 2010). *GILKES* was asked for an updated quote using the 2004 to 2009 data set as a representative range in values. The hope is for the *GILKES* designed turbine to be centered on the flow and head conditions (flow of 1.3 m^3/s and head of 48 m) used in the analysis above. An estimate for a 3 turbine system completed in 2004 by *Small Hydro Controls*, Kimberly, B.C. Canada (Planit Management and Stantec Consulting, 2004) is found in the Appendix 3.

The quoted powerhouse price range was found to between \$400,000 – \$625,000 Canadian Dollars. Therefore, an expected price of **\$600,000** was set for the powerhouse. The powerhouse cost was estimated to be 40 percent (%) of the total costs of the project. It was shown by Ogayar and Vidal (2009) that the powerhouse is a significant portion of the total cost of a hydro power project. Of the total powerhouse costs, the generation unit is estimated to cost 2/3 of the powerhouse costs, or in this case \$400,000. A series of formulae or equations can be solved to determine potential costs (Aggidis et al., 2010) and tool to predict costs. Note that the proposed prices were from 2003 and a favorable Canadian Dollar to the United Kingdom Pound has allowed for a lower price than quoted in 2003.

By allocating a percentage of the total price to the powerhouse, a total expected price was obtained. *Best*, *Expected*, and *Worst* case scenarios were analyzed from the expected case costs. The three cost and sensitivity analyses are listed below:

- Best case scenario costs two thirds (2/3) of the expected cost
- Expected case scenario was based off of quoted costs
- Worst case scenario costs two times (2x) the expected cost

Determining the electricity export rate is by far one of the most important and challenging variables in this study. There are a series of possibilities on how to best use the produced electricity, and these options are discussed in the *CRD Market Options* section of this paper. It should be noted that *BC Hydro* is a quasi government/private interest corporation which holds a majority to a monopoly type of grasp on the electricity generation, transmission, and distribution in British Columbia. Therefore, the likely progression of this proposed idea would have to involve *BC Hydro*.

Two price analyses were performed on the best, expected, and worst case scenarios. The variable prices are referred to as *Trial 1* and *Trial 2* and are discussed in more detail below.

Trial 1:

Electricity Export Rate: 0.0921 Canadian Dollars ($) per kilowatt hour (kWh), or 92.1 dollars per megawatt hour ($/MWh) (Hydro Quebec, 2010).

Note that the above export rate (Trial 1) is not a firm quoted rate, but it is an estimated value. For such a project to take place there would need to be in depth conversations and consultations regarding export prices with *BC Hydro*. In the case that *BC Hydro* is not the purchaser of the electricity, it would be the responsibility of the purchaser, not the Victoria *CRD*, to meet all standards (including health and safety standards) and responsibility for this process. The price above (Trial 1) is inflated when compared to the current market rate paid by the *CRD*. Incentives, green credits, or another form of price subsidy was incorporated into Trial 1 price.

A second price (Trial 2) is seen below, and was estimated from the two-stepped *BC Hydro* rate system for the price of electricity that the Victoria *CRD* currently purchases. From this two-stepped system it is estimated that the *CRD* pays between 5 and 6 cents per kilowatt hour ($/kWh), for electricity. In comparison, in the year 2000, it was estimated that Boulder, Colorado received about $800,000 in revenue from its 5 generation units (CADDET, 2000). The export price used in this 2000 analysis was $0.05 per kilowatt hour ($0.05/kWh). When comparing the Trial 1 and Trial 2 export rates, the Trial 1 export rate price is approximately 50 percent (%) higher than the current *CRD* purchasing price.

Trial 2:

Electricity Export Rate: 0.055 Canadian Dollars ($) per kilowatt hour (kWh), or 55.0 dollars per megawatt hour ($/MWh).

Cost analyses were performed on all three case scenarios: best, expected, and worst cases. These scenarios were run under both Trial 1 and Trial 2 prices, for a total of 6 scenarios.

Six sets of conditions were modeled: Trial 1 Price for the Best, Expected, and Worst Case, and Trial 2 Price for the Best, Expected, and Worst Case scenarios.

5.2) RETSCREEN - PROJECT INFORMATION ENTRIES:

RETScreen project information entries are list below. Items in **bold** refer to RETScreen field name, and items in normal font were entered by the user. Note that descriptions of some of the more obscure fields are given below it.

Project Name: CRD Humpback, PRF

Project Location: Victoria, BC, Canada

Prepared For: M.SC. Thesis

Prepared By: Eri A. Boye

Project Type: Power

Technology: Hydro Turbine

Grid Type: Central-Grid

(A central-grid with an internal component is available, but not studied in this paper. It should be noted that the power generated from a turbine located at the Humpback PRF could be used internally, and still have a grid interconnect for any electricity surplus or deficit.)

Analysis Type: Method 2

Heating Value Reference: Higher Heating Value (HHV)

Climate Data Location: Victoria Int'l Airport

(By setting the location of the climate data, RETScreen will incorporate the meteorological data into the analysis.)

5.3) RETSCREEN – ENERGY MODEL AND POWER PROJECT GENERAL ENTERIES:

RETScreen project information entries are list below. Items in **bold** refer to RETScreen field name, and items in normal font were entered by the user. Note that descriptions of some of the more obscure fields are given below it.

Analysis Type: Method 2

Proposed Project: Reservoir

Gross Head: 48 (m)

Maximum Tailwater Effect: 0.00 (m)

Residual Flow: 0.00 (m^3/s)

Percent Time Firm Flow Available: 85 (%)

Design Flow: 1.3 (m^3/s)

Turbine Type: Francis

Turbine Efficiency: Standard

Number of Turbines: 1

Design Coefficient: 5.0

(5.0 is a casted or fabricated stainless steel runner produced by a major manufacturer, designed with the benefit of computational fluid dynamics (CFD) software and blades bent to a desired profile by a press.)

Efficiency Adjustment: 0.0 (%)

Flow Values (m^3/s) for the Flow Duration Curve (FDC): 2009 Flow Data (m^3/s) were used

Maximum Hydraulic Losses: 10 (%)

Miscellaneous Losses: 5 (%)

Generator Efficiency: 95 (%)

Availability: 95 (%)

(This represents about 18 days of equivalent down time per year.)

Power Available Flow Adjustment Factor: 1.1

(This would allow for a micro sensitivity analysis to account for a possible variation of 1.1 times (1.1x) for all values in the flow duration curve (FDC).)

5.4) TRIAL 1 PRICE – BEST CASE SCENARIO:

The following items below are the variables that vary from scenario to scenario, and represent the type of analysis. The results from RETScreen are found in the table (Table 15) and the figure (Figure 26) below.

Electricity Export Rate: 0.0921 Canadian Dollars ($) per kilowatt hour (kWh), or 92.1 dollars per megawatt hour ($/MWh)

Feasibility Cost: 10,000 ($)

Development Cost: 400,000 ($)

Engineering Cost: 100,000 ($)

Hydro Turbine Cost: 941 ($/kW)

Contingencies Rate: 8 (%) or 72,837 ($)

Interest During Construction: 10 (%), for a duration of 12 Months – 49,165 ($)

Total Initial Cost: 1,032,459 ($)

O&M Parts and Labour: 50,000 ($)

User-Defined Cost, Turbine Re-Fit: Occurs at year 21, costs 250,000 ($)

Fuel Cost Escalation Rate: 0 (%)

Inflation Rate: 2.0 (%) (Statistics Canada, 2010)

Discount Rate: 7.0 (%)

Project Life: 40 (yrs)

Incentives and Grants Entry: 100,000 ($)

(This is set to $100,000, but there are increasing grants and other monetary incentives available).

Debt Ratio: 65 (%)

(This is the amount of money borrowed compared with the money used).

Debt Interest Rate: 5.69 (%)

(Rate used is 2% above the long term *Bank of Canada* Benchmark Yield Rate) (Bank of Canada, 2010)

Debt Term: 20 (yrs)

(This is the length of time that debt is being paid on the project).

Table 15: Trial 1 price under a best case scenario, summary of results from RETScreen.

Financial Viability: Trial 1 Price Best Case Scenario		
Pre-tax IRR - equity	%	64.20%
Pre-tax IRR - assets	%	17.50%
Simple payback	yr	4.1
Equity payback	yr	1.5
Net Present Value (NPV)	$	1,873,863
Annual life cycle savings	$/yr	140,557
Benefit-Cost (B-C) ratio		6.19
Debt service coverage		3.97
Energy production cost	$/MWh	45.46
GHG reduction	tCO2/yr	591.6
CO2 Car/light Truck	Equiv	108
CO2 40yr Reduction	tCO2/yr	23,666

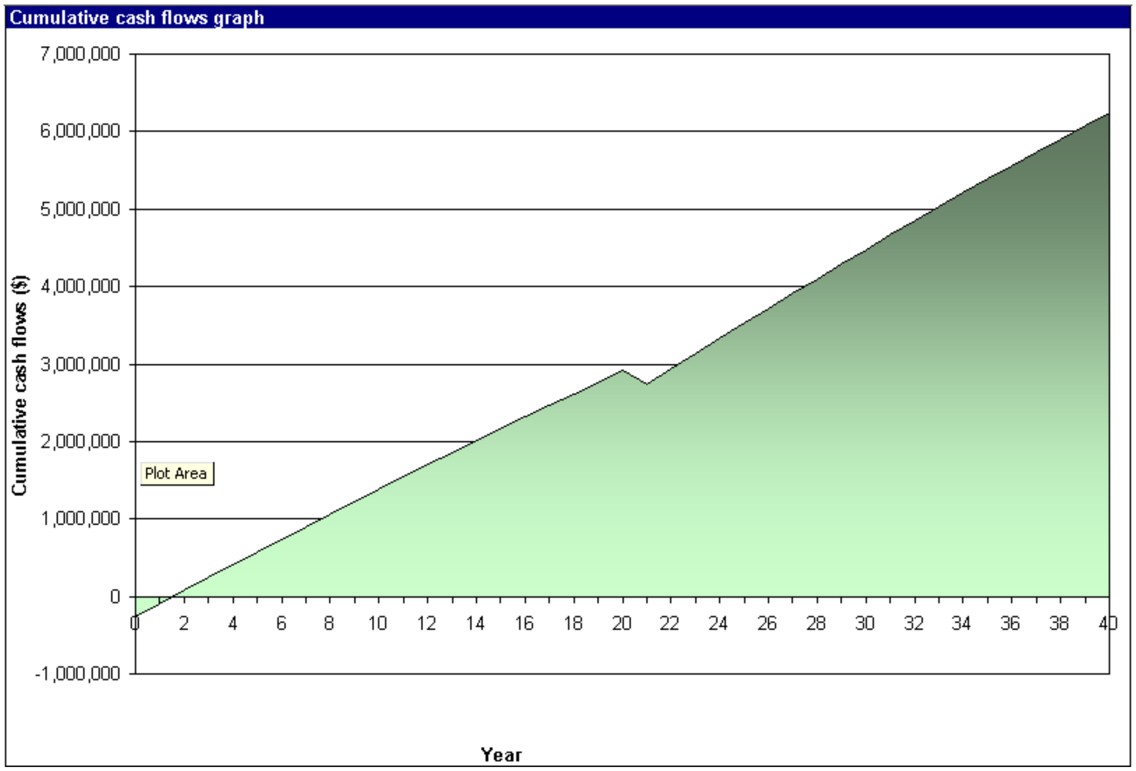

Figure 26: Trial 1 price under a best case scenario, cumulative cash flow graph from RETScreen.

5.5) TRIAL 2 PRICE – BEST CASE SCENARIO:

The major difference from the previous example (Trial 1 price, best case) and this case is the price that the electricity is sold for. In this example, the export rate goes from 92.1 to 55.0 dollars per megawatt hour ($/MWh). This is the estimated price that the *CRD* pays for electricity to operate the system, or an offset value.

Items below in italics should be noted, as they are considered important or have changed from the above scenario. If no variables are mentioned below, they are the same in this scenario as in the previous one.

The results from RETScreen are found in the table (Table 16) and the figure (Figure 26) below.

***Electricity Export Rate**: 0.055 Canadian Dollars ($) per kilowatt hour (kWh), or 55.0 dollars per megawatt hour ($/MWh)*

Table 16: Trial 2 price under a best case scenario, summary of results from RETScreen.

Financial Viability: Trial 2 Price Best Case Scenario		
Pre-tax IRR - equity	%	19.80%
Pre-tax IRR - assets	%	4.20%
Simple payback	yr	8.1
Equity payback	yr	4.7
Net Present Value (NPV)	$	383,146
Annual life cycle savings	$/yr	28,739
Benefit-Cost (B-C) ratio		2.06
Debt service coverage		2.01
Energy production cost	$/MWh	45.46
GHG reduction	tCO2/yr	591.6
CO2 Car/light Truck	Equiv	108
CO2 40yr Reduction	tCO2/yr	23,666

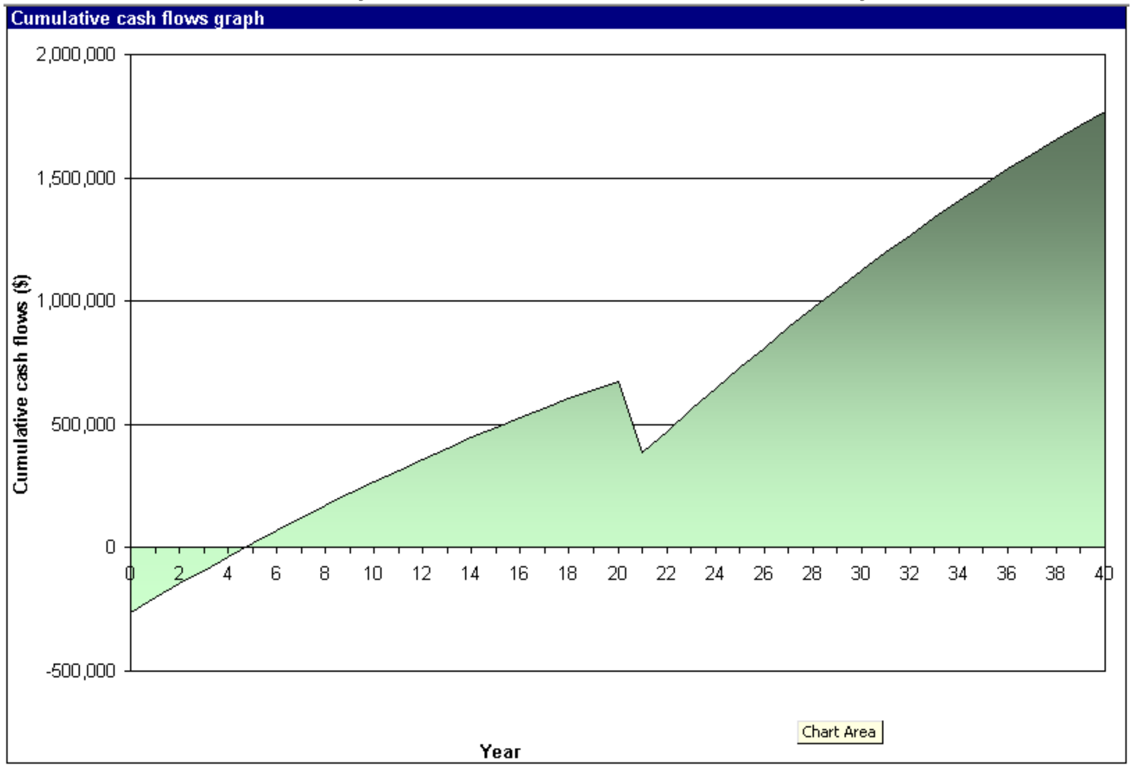

Figure 27: Trial price 2 under a best case scenario, cumulative cash flow graph from RETScreen.

5.6) TRIAL 1 PRICE – EXPECTED CASE SCENARIO:

This is the scenario with the expected estimated cost, and with the higher electricity export rate.

Items below in *italics* should be noted, as they are considered important or have changed from the above scenario. If no variables are mentioned below, they are the same in this scenario as in the previous one.

The results from RETScreen are found in the table (
Table 17) and in figure below (Figure 28).

***Electricity Export Rate**: 0.0921 Canadian Dollars ($) per kilowatt hour (kWh), or 92.1 dollars per megawatt hour ($/MWh)*

***Feasibility Cost**: 15,000 ($)*

***Development Cost**: 600,000 ($)*

***Engineering Cost**: 150,000 ($)*

***Hydro Turbine Cost**: 1412 ($/kW)*

Contingencies Rate: 8 (%) or 109,272 ($)

Interest During Construction: 10 (%), for a duration of 12 Months – 73,759 ($)

Total Initial Cost: 1,548,929 ($)

O&M Parts and Labour: 50,000 ($)

User-Defined Cost, Turbine Re-Fit: Occurs at year 21, costs 250,000 ($)

Fuel Cost Escalation Rate: 0 (%)

***Inflation Rate**: 2.5 (%)* (Statistics Canada, 2010)

***Discount Rate**: 8.0 (%)*

Project Life: 40 (yrs)

***Incentives and Grants Entry**: 0 ($)*

(This is set to $0, but there are increasing grants and other monetary incentives available).

Debt Ratio: 65 (%)

(This is the amount of money borrowed compared with the money used).

***Debt Interest Rate**: 6.69 (%)*

(Rate used is 2% above the long term *Bank of Canada* Benchmark Yield Rate) (Bank of Canada, 2010)

Debt Term: 20 (yrs)

(This is the length of time that debt is being paid on the project).

Table 17: Trial 1 price under an expected case scenario, summary of results from RETScreen.

Financial Viability: Trial 1 Price Expected Case Senario		
Pre-tax IRR - equity	%	23.50%
Pre-tax IRR - assets	%	7.70%
Simple payback	yr	6.8
Equity payback	yr	4.1
Net Present Value (NPV)	$	957,191
Annual life cycle savings	$/yr	80,270
Benefit-Cost (B-C) ratio		2.77
Debt service coverage		2.44
Energy production cost	$/MWh	65.47
GHG reduction	$/tCO2	591.6
CO2 Car/light Truck	Equiv	108
CO2 40yr Reduction	tCO2/yr	23,666

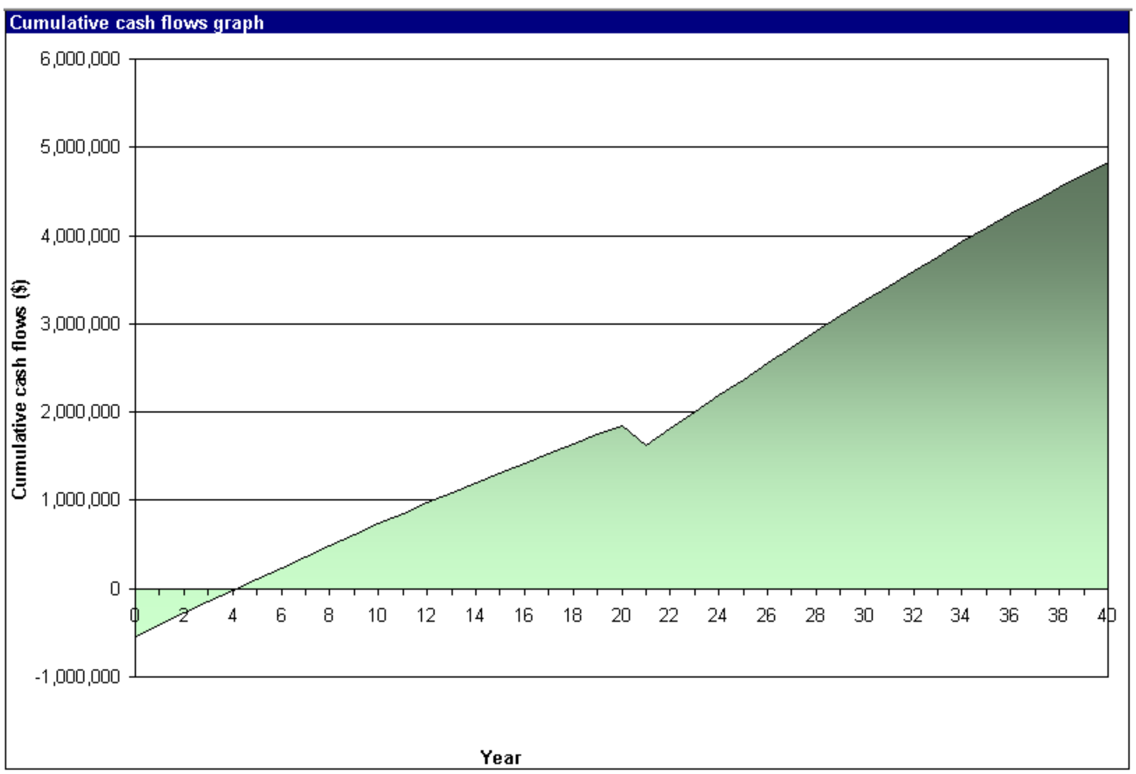

Figure 28: Trial price 1 under an expected case scenario, cumulative cash flow graph from RETScreen.

5.7) TRIAL 2 PRICE – EXPECTED CASE SCENARIO:

The major difference from the previous example (Trial 1 price, expected case) is the price that the electricity is sold for. In this example, the rate goes from 92.1 to 55.0 dollars per megawatt hour. This is the estimated price that the *CRD* pays for electricity to operate the system, or an offset value.

Items below in italics should be noted, as they are considered important or have changed from the above scenario. If no variables are mentioned below, they are the same in this scenario as in the previous one.

The results from RETScreen are found in the table (Table 18) and the figure (Figure 29) below.

Electricity Export Rate*: 0.055 Canadian Dollars ($) per kilowatt hour (kWh), or 55.0 dollars per megawatt hour ($/MWh)*

Table 18: Trial 2 price under an expected case scenario, summary of results from RETScreen.

Financial Viability: Trial 2 Price Expected Case Senario		
Pre-tax IRR - equity	%	1.90%
Pre-tax IRR - assets	%	-1.80%
Simple payback	yr	13.4
Equity payback	yr	31.6
Net Present Value (NPV)	$	-376,189
Annual life cycle savings	$/yr	-31,547
Benefit-Cost (B-C) ratio		0.31
Debt service coverage		1.18
Energy production cost	$/MWh	65.47
GHG reduction	$/tCO2	591.6
CO2 Car/light Truck	Equiv	108
CO2 40yr Reduction	tCO2/yr	23,666

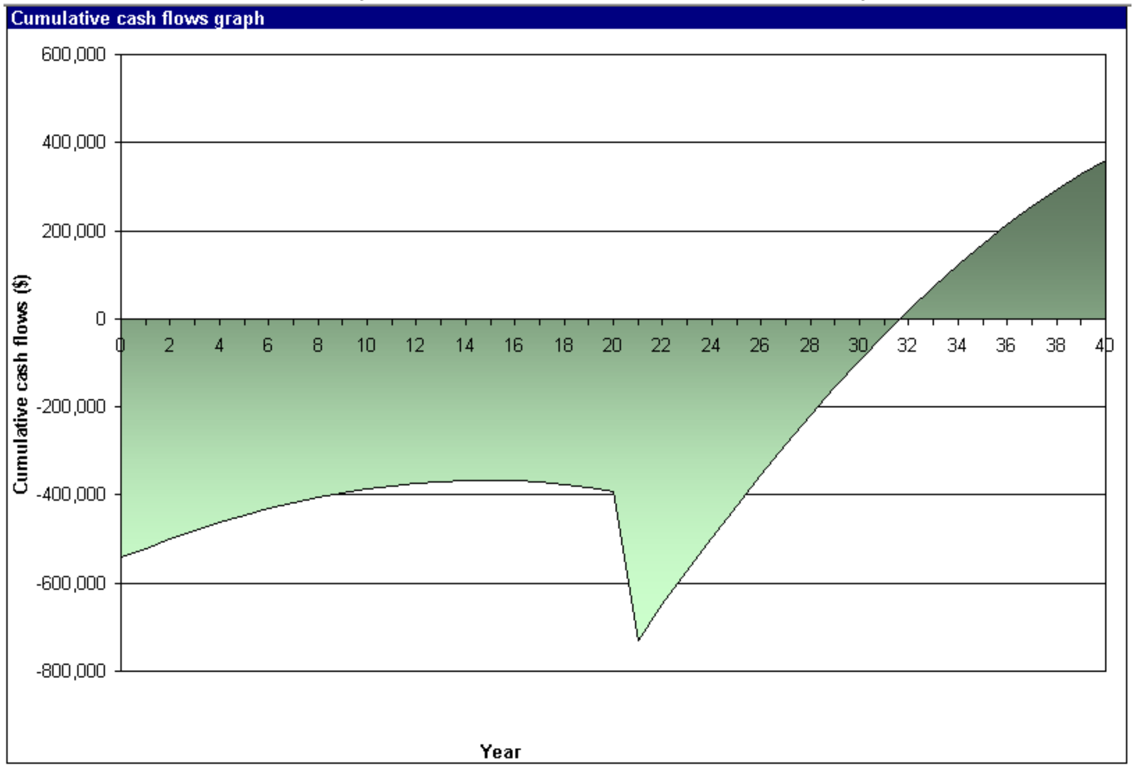

Figure 29: Trial price 2 under an expected case scenario, cumulative cash flow graph from RETScreen.

5.8) TRIAL 1 PRICE – WORST CASE SCENARIO:

This is the scenario with the worst estimated cost, and with the higher electricity export rate.

Items below in italics should be noted, as they are considered important or have changed from the above scenario. If no variables are mentioned below, they are the same in this scenario as in the previous one.

The results from RETScreen are found in the table (

Table 19) and the figure (Figure 29: Trial price 2 under an expected case scenario, cumulative cash flow graph from RETScreen.Figure 30) below.

Electricity Export Rate*: 0.0921 Canadian Dollars ($) per kilowatt hour (kWh), or 92.1 dollars per megawatt hour ($/MWh)*

Feasibility Cost*: 22,500 ($)*

***Development Cost**: 900,000 ($)*

***Engineering Cost**: 225,000 ($)*

***Hydro Turbine Cost**: 2118 ($/kW)*

Contingencies Rate: 8% or 163,908 ($)

Interest During Construction: 10 (%), for a duration of 12 Months – 110,638 ($)

Total Initial Cost: 2,323,394 ($)

O&M Parts and Labour: 50,000 ($)

User-Defined Cost, Turbine Re-Fit: Occurs at year 21, costs 250,000 ($)

Fuel Cost Escalation Rate: 0 (%)

***Inflation Rate**: 3.0 (%)* (Statistics Canada, 2010)

***Discount Rate**: 9.0 (%)*

Project Life: 40 (yrs)

***Incentives and Grants Entry**: 0 ($)*

(This is set to $0, but there are increasing grants and other monetary incentives available.)

Debt Ratio: 65 (%)

(This is the amount of money borrowed compared with the money used.)

***Debt Interest Rate**: 7.69 (%)*

(Rate used is 2% above the long term *Bank of Canada* Benchmark Yield Rate) (Bank of Canada, 2010)

Debt Term: 20 (yrs)

(This is the length of time that debt is being paid on the project.)

Table 19: Trial 1 price under a worst case scenario, summary of results from RETScreen.

Financial Viability: Trial 1 Price Worst Case Senario		
Pre-tax IRR - equity	%	8.50%
Pre-tax IRR - assets	%	2.10%
Simple payback	yr	10.2
Equity payback	yr	12.3
Net Present Value (NPV)	$	-44,331
Annual life cycle savings	$/yr	-4,121
Benefit-Cost (B-C) ratio		0.95
Debt service coverage		1.48
Energy production cost	$/MWh	93.47
GHG reduction	$/tCO2	591.6
CO2 Car/light Truck	Equiv	108
CO2 40yr Reduction	tCO2/yr	23,666

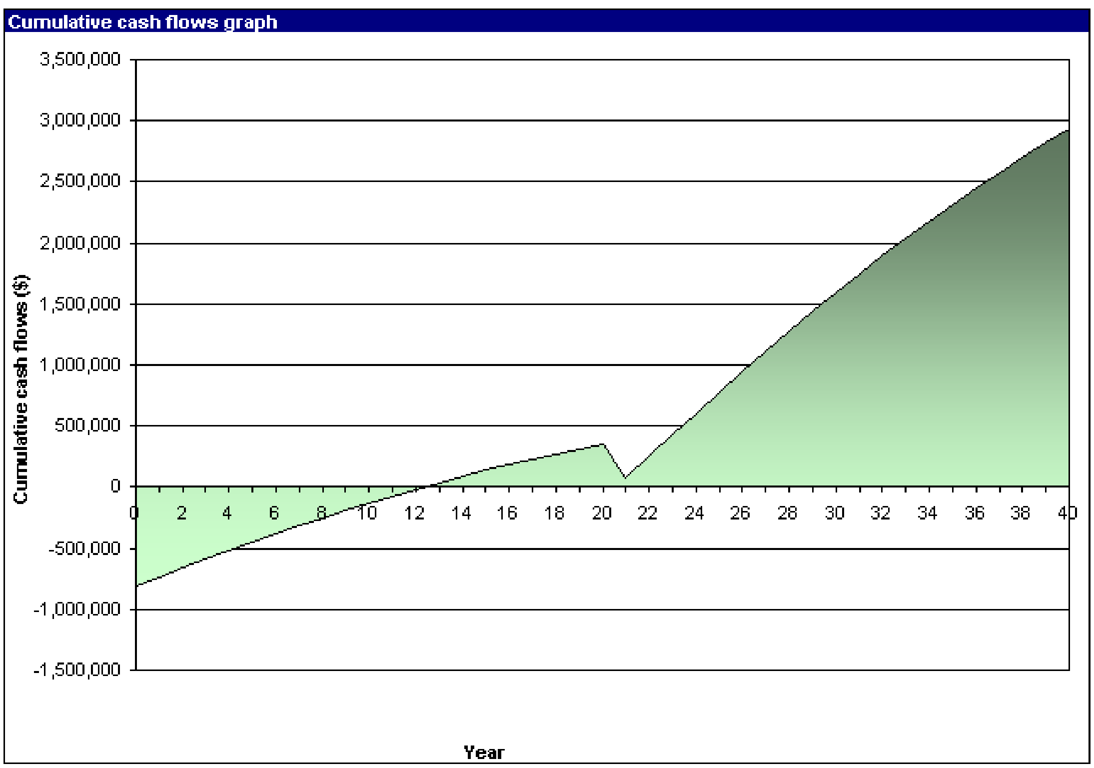

Figure 30: Trial price 1under a worst case scenario, cumulative cash flow graph from RETScreen.

5.9) TRIAL 2 PRICE – WORST CASE SCENARIO:

The major difference from the previous example (Trial 1 price, worst case) is the price that the electricity is sold for. In this example, the rate goes from 92.1 to 55.0 dollars per megawatt hour. This is the estimated price that the *CRD* pays for electricity to operate the system, or an offset value.

Items below in italics should be noted, as they are considered important or have changed from the above scenario. If no variables are mentioned below, they are the same in this scenario as in the previous one.

The results from RETScreen are found in the table (Table 20) and the figure (Figure 31) below.

***Electricity Export Rate**: 0.055 Canadian Dollars ($) per kilowatt hour (kWh), or 55.0 dollars per megawatt hour ($/MWh)*

Table 20: Trial 2 price under a worst case scenario, summary of results from RETScreen.

Financial Viability: Trial 2 Price Worst Case Senario		
Pre-tax IRR - equity	%	-6.20%
Pre-tax IRR - assets	%	-7.60%
Simple payback	yr	20.1
Equity payback	yr	> project
Net Present Value (NPV)	$	-1,247,192
Annual life cycle savings	$/yr	-115,938
Benefit-Cost (B-C) ratio		-0.53
Debt service coverage		0.5
Energy production cost	$/MWh	93.47
GHG reduction	$/tCO2	591.6
CO2 Car/light Truck	Equiv	108
CO2 40yr Reduction	tCO2/yr	23,666

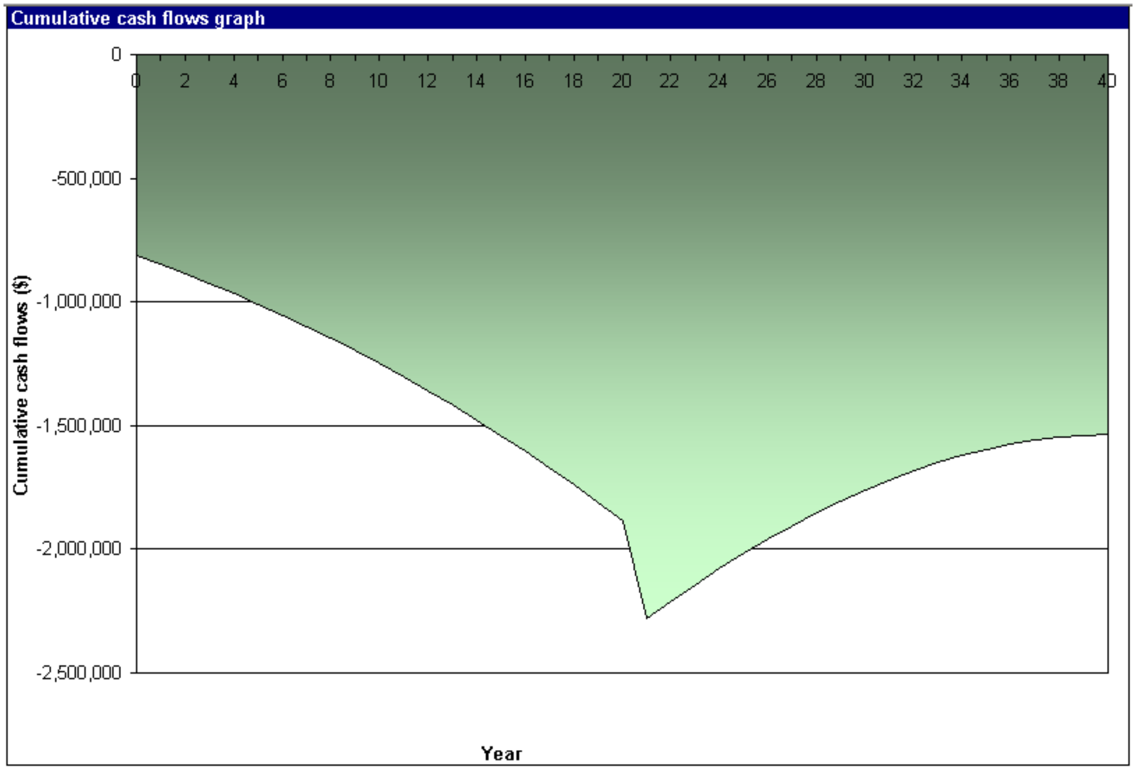

Figure 31: Trial price 2 under a worst case scenario, cumulative cash flow graph from RETScreen.

6.0) PENALTIES:

In an effort to be complete, the *CRD* must be aware that the failure to provide an agreed amount of electricity at any time could result in severe consequences, and as a result it could be heavily penalized by *BC Hydro* or any other purchaser of that electricity. To not deliver to oneself would be also detrimental, and could also come at great financial expense as the treatment plants and other processes could fail to operate.

These penalties do not account for possible economic losses as a result of poor economic conditions. They would provide added losses to a losing situation if the power production was not able to meet the agreed upon terms.

6.1) LIQUIDATION DAMAGES:

Due to the dynamic nature of the electricity economic markets, there is a financial penalty that may have to be paid by the contracted electricity producer to the buyer if the production schedule is not met. The terms of agreement would set up a set of legal conditions guaranteeing production and outlining the resulting penalties. For example, a yearly guaranteed quantity of electricity could be required. The scheduled delivery could be flexible, and the resulting deficit (if any) could result in a returning of the missed quantity in an equivalent increased amount of electricity supplied the following year, or a return of equivalent amount of paid money.

Note: the type of delivery and supply contract in effect would also make a difference to the potential penalties occurred. A *Competitive Price Agreement*, in contrast to a *Load Displacement Option*, would have different liquidation damages penalties.

It should be noted that *BC Hydro* has become more flexible to the idea of intermittent power sources. A price deduction or a payment option may be possible and could allow for less penalty should the scheduled production amount of electricity not be met. This should be discussed with *BC Hydro* if or when such talks arise; this is generally referred to by *BC Hydro* as the *Natural Resource Adjustment Option*.

7.0) CRD MARKET OPTIONS:

This acknowledges that there are a number of options that the *CRD* has regarding the option of installing a turbine at the Humpback PRF. Below are a limited number, but rational in choice, set of options. It should be noted here that the current price for electricity is on the rise in B.C., as *BC Hydro* has just been granted a 6.11% rate increase by the governing commission.

7.1) WAIT AND SEE OPTION:

This option accredits that this project may or may not be viable, and at the same time chooses not to address it at this current time. Limited to no further resources are allocated toward this option; however, it could be re-visited at a later time.

7.2) ALLOW A THIRD PARTY INVOLVEMENT / RELINQUISHING OWNERSHIP:

During any part of the process, the *CRD* can decide to involve an outside partner to become evolved or to take over the project. A table below (Table 21) summarizes the options and steps involved in this project. It should be noted that the options are presented in decreasing risk and return to the *CRD*. As the *CRD* limits the risk that it is exposed to, it also limits the profitability of the project for the *CRD*. From the table below (Table 21), and through consultation with the *CRD*, it appears as if the fourth option (*CRD* Option # 4) would be the most attractive, as the *CRD* would like to distance itself from the responsibility and commitment of resources for such a project.

Table 21: Options for the CRD to consider when considering 3rd party ownership.

CRD and Third Party Involvement Options for Electricity Generation at the Humpback PRF							
CRD Option #	Regulations and Feasibility	Design	Build	Own	Operate	Risk to CRD	Return to CRD
1	CRD	CRD	CRD	CRD	CRD	Highest	Highest
2	CRD	3rd Party	3rd Party	CRD	3rd Party	Mod/High	Mod/High
3	3rd Party	3rd Party	3rd Party	CRD	3rd Party	Moderate	Moderate
4	CRD	3rd Party	3rd Party	3rd Party	3rd Party	Low/Mod	Low/Mod
5	3rd Party	3rd Party	3rd Party	3rd Party	3rd Party	Lowest	Lowest

7.3) APPROACH BC Hydro ABOUT A COMPETITIVE PRICE AGREEMENT:

This process has both involves entering into an agreement with *BC Hydro* to produce power, and that power will be unconditionally purchased. This process offers a market fair price, and there are both renewable energy incentives and financing available through the agreement. This process is very rigid, controlled, and firm. As a result, the process can take an extended duration of time to come to fruition. It should also be seriously noted, that there are steep financial penalties for the non delivery of agreed upon electricity.

7.4) APPROACH BC HYDRO ABOUT A POWER SMART LOAD DISPLACEMENT OPTION:

This is the alternative option with *BC Hydro*, to use the possible electricity generated locally to offset the electricity purchased from *BC Hydro.* This option has not been studied in-depth in this analysis, but should be noted as a potential viable option. The electricity generated on site at the Humpback PRF could be used to power the processes that occur in the upstream treatment plants. Any deficiency in electricity could be purchased from *BC Hydro* at the current or spot rate. For *BC Hydro* load displacement, which is that no surplus electricity is produced and therefore none has to be accepted onto the grid, is the preferable option. This route would have to be studied in-depth and to a level of satisfaction set by *BC Hydro*, for them to enter into this type of agreement. *BC Hydro* could be willing to aide in the cost of any monitoring or smart equipment used in this option.

7.5) SELL THE ELECTRICITY TO A THRID (3RD) PARTY:

This option involves the generation and possibly the transmission and distribution of the produced electricity to a third party buyer. Regulations are on-going about this process in B.C., and as a result this agreement is normally considered as a later option.

8.0) CRD INTERCONNECTION POINT TO THE BC HYDRO NETWORK:

Depending on the way that the *CRD* decides to handle this proposed hydro turbine, an appropriate connection system allowing the produced electricity to be delivered to the buyer is required. In the case of a *Load Displacement Option* versus a *Competitive Price Agreement* less equipment and finances would be required to set it up. A picture of the *BC Hydro* network is shown in the figure below (Figure 32).

Figure 32: Figure showing the nearby BC Hydro powerpole and transformers. Picture taken from the Humpback PRF and was provided by the CRD.

BC Hydro has estimated that it would cost between $40,000 and $50,000 to connect the current three (3)-phase system to the potential *CRD* electricity generating station. An interconnect point and rough list of standard necessary equipment is described below, and was provided by *BC Hydro*. A flow chart with the *BC Hydro* Standing Offer Program (SOP) is given in the Appendix 4.

- **Feeder Name**: Feeder # 25F72 CLD, at the intersection of Humpback and Irwin Road. Termination occurs at the Colwood Substation.
- **Revenue Metering Equipment**: Options include monthly metering by *BC Hydro* or remote reading via an internal intranet.
- **Protection and Control**: A study for the aggregate generation on Feeder # 25F72 CLD would have to be conducted to see if the kVA of the feeder exceed 1,340 kVA at any time.

- **Communication Equipment**: No additional communication equipment should be needed.

9.0) PROJECT WATER LICENSING AND PERMITTING:

The *CRD*, or the organization responsible for the power production, should be aware of the required governmental processes involved in this process. It should be noted that the local and provincial governing bodies may be required to participate actively in this proposed project.

Water licensing is a good example of the involvement that the B.C. Provincial Government must have in this project. Below is a summary of the required items that need to be submitted to the B.C. Government in order to start the water licensing application process (British Columbia Government, 2010).

Below is a list of items that will have to be completed to begin the Water Licensing and Permitting processes. Note: this list is not to be considered complete in nature.

- B.C. Government Water License Application form, accurately and fully completed
- Completed Required Schedule Forms (example: Schedule 3 – Power Information) are required in support of a Water License Application for power production
- Land Tile Record for the area in question, provided by an approved source
- Maps and Aerial Photographs showing property effected
- A letter from the *CRD* showing its involvement
- A list of the *CRD*'s current Water Licenses
- A Preliminary Project Definition and Scope
- Project and Structural Drawings or Schematics
- Payment for Application

- A Possible Environment Impact Assessment (E.I.A.) depending on what the B.C. Government decides.

10.0) CONCLUSIONS – A SUMMARY OF ANALYSES:

The *CRD* provided hourly flow and pressure data for the years of 2004, 2005, 2006, 2007, 2008, and 2009. These data sets were cleaned and analyzed. The feasibility study looked at the Humpback PRF as a possible location for a hydropower generation station. It was observed (CADDET, 2000) in Boulder, Colorado that the best location to install hydropower generation units on a municipal waterway is at the location where pressure is released from the system.

The idea of combing potable water supply waterways and hydropower is starting to gain interest globally (Kucukali, 2010), (Wa et al., 2010), (Pigaht and Van Der Plas, 2009).

After reviewing the provided years of data for the Humpback PRF, a potential flow and pressure head regime was established with:

1.3 cubic meters of water per second (m^3/s)
48 metres (m) of head

This resulting flow regime shows that the proposed project and project location site could be feasible to use as a location for electricity generation.

Frictional head losses were found to be minimal with 1 meter of head loss occurring under high flow conditions in the Kapoor Tunnel and surrounding waterways. It should be noted that these calculations are limited in design, as their purpose was to observe the significance of head losses due to friction in the waterways. Head losses in the treatment plants are of far greater importance and should be studied in the future (under a range of flow conditions).

It should be noted here that at the time this paper was submitted for review, *GILKES* submitted an updated budget which appears in the Appendix 2. This updated budget cost $560,000 Canadian Dollars for the major equipment used in the powerhouse. This quoted value is below, but close to, the estimated $600,000 used for the expected case scenarios.

Based on the above design factors, the proposed project would provide electricity to 250 Victoria area homes year round (Table 22). In comparison, it is shown (CADDET, 2000) that such a system can be applied to a municipal system. CADDET, estimated that in the year 2000, seven percent (7%) of the electricity consumed in Boulder, Colorado was produced in the municipal waterways.

Table 22: RETSceen summary of potential elecritiy production at the Humpback PRF.

RETScreen Summary of Electricity Generation		
Turbine power rating	*kW*	426
Capacity factor	*%*	80.8%
Electricity exported to grid	*MWh*	3,014

Six (6) scenarios were run in the economic analyses and a summary of the input variables and results are seen in the table below (Table 23). It is shown with in this study that the economic feasibility of this project is linked to the export rate of electricity, future economic conditions, and incentives. It should be noted here that this project, over a 40 year time span, will eliminate 23,666 tones of carbon dioxide (tCO_2) from being produced by the current means of generating electricity in British Columbia. The electricity produced in B.C. is dominantly produced by hydropower. Therefore, if such a system as proposed in this thesis was introduced into an electrical system where fossil fuels are the dominant energy source, the resulting eliminated tones of carbon dioxide would be greater.

Table 23: Summary of the six (6) economic scenarios studies for the Humpback PRF, IRR is shown in percent (%).

Economic Scenarios for an Electricity Generation Station at the *CRD's* Humpback PRF						
RETScreen Economic Variables	Trial Price 1, Best	Trial Price 2, Best	Trial Price 1, Expected	Trial Price 2, Expected	Trial Price 1, Worst	Trial Price 2, Worst
Export Rate ($/MWh)	92.1	55.0	92.1	55.0	92.1	55.0
Initial Total Cost ($)	1,032,459	1,032,459	1,548,292	1,548,292	2,323,394	2,323,394
Inflation Rate (%)	2.0	2.0	2.5	2.5	3.0	3.0
Discount Rate (%)	7.0	7.0	8.0	8.0	9.0	9.0
Grants ($)	100,000	100,000	0.0	0.0	0.0	0.0
Pre-Tax IRR on equity	62.4	19.8	23.5	1.9	8.5	-6.2

The table above (Table 23) shows that the project could be very profitable, with an internal rate of return (IRR) of over 60%, if all the idea variables occurred. In contrast, the proposed project would become bankrupt (IRR of -6.2%) if the entire set of variables in the worst case scenario occurred. This return on equity does not account for penalties, or other economical punishment which could be accrued.

It should be noted here that the construction of the Sunshine Hydro Station in Boulder Colorado was completed in 1987. The Sunshine Station location has elevated flow and head conditions when compared to the Humpback PRF, but these two facilities are similar to each other in nature. A powerhouse with the capacity of 800 kilowatts was installed at the Sunshine location. The installed powerhouse at the Sunshine station is almost twice as big as the one proposed at the Humpback PRF. The construction costs of the Sunshine project were $1,100,000 USD (CADDET, 2000), which compare nicely to the expected costs in this analyses. With an export rate of 5 cents per kilowatt hour ($0.05/kWh) CADDET estimated that in 2000 the Sunshine Hydroelectric Facility brought in almost $180,000 USD in revenue.

It is the author's opinion, after conducting all of the analyses and deliberation on the results, that the proposed project is technically and economically feasible at the Humpback PRV. Under the conditions described throughout, this project has shown that it is economically sensitive and technically complex in nature. As shown in the scenarios conducted above, the rate of return is variable. This variability generates the chance for low profit to loss conditions, which are not appealing to private capitol.

The author would like to acknowledge the potential for other benefits from this project. In the initial stages of this project, or where this idea currently exists, the *CRD* could offer the proposed ideas to the public in the form of an open house, or information sharing session. Public participation could be required as part of an E.I.A., and either way it is fair to inform the public (including First Nations governing bodies) about changes to their potable drinking water system(s).

If the proposed project processes were to come into fruition, the *CRD* could showcase the facility as an alternative energy combined cycle system. The project engineering, powerhouse equipment and electronics, and processes involved with in these systems could be available to the general public for the purpose of education and inspiration. Note that the proposed system would add an additional control or safety mechanism to the existing municipal waterways in the form of the control gates.

Surge and water hammer analyses should be looked at once a powerhouse design size is established.

The next steps for this proposed project are in the hands of the *CRD*. It is the duty of the *CRD* to decide, on behalf of the best interest of the public, what happens within their waterways.

A list of possible next steps for the *CRD* are listed below:

- Review possible green credits, incentives, and grants that this project could qualify for
- Open dialogs with the British Columbia Government and water licensing board
- Review the current *CRD* mandate and choose to ratify it to include the duties of an electrical utility
- Choose a marketing option and negotiate a best possible export rate with the least penalties

- Choose if and when a third (3rd) party should take over the project control (risk analysis)
- Collaborate with *BC Hydro*, consultants, and contractors as needed
- Apply for an interconnection with *BC Hydro*'s electrical network
- Apply for the necessary building permits

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APPENDIXES:

APPENDIX 1) CRD KEY SERVICES | OUR KEY DELIVERABLES:

The CRD provides services, explores issues, undertakes initiatives and advocates in areas best addressed at a regional level.

Current functions include:

- Water Services
- Waste Management (solid and liquid)
- Regional parks and trails
- Regional planning and transportation
- Hazmat
- Emergency and disaster planning, 911
- Climate action
- Housing
- Finance

Sub-Regional Services

The CRD provides the political and administrative framework for a combination of municipalities to collaborate in the provision of sub-regional services, including:

- Parks and recreation (SEAPARC and Panorama/Peninsula)
- Storm water quality
- Sewer systems and wastewater treatment
- Water distribution and support for water commissions
- Emergency dispatch
- Arts, grants and theatre
- Housing Trust
- Regional History Society

Local/Electoral Area Services

The CRD serves as a local government for electoral areas, providing for or supporting:

- Electoral area planning
- Water Services
- Waste management
- Bylaw and regulatory services
- Building inspection
- Animal control

- Community transit and transportation
- Parks and recreation
- Fire protection
- Emergency disaster response
- Library and harbour services
- Search and rescue
- Economic development
- House numbering
- Electrification
- Street lighting

We fulfill our mission by providing services in the following areas:

- Municipal Finance
- Health Facilities Planning
- Environmental Waste Management
- Recreation, Parks and Leisure Services
- Regulatory Services
- Affordable Housing
- Water Supply
- Regional Planning Services
- 9-1-1 Emergency Response

APPENDIX 2) GILKES: DATA PROVIDED, HUMPBACK PRF BUDGET ESTIMATES:

GILKES

www.gilkes.com

BUDGET PROPOSAL

Quotation Ref :	BMS/humpback
Sales Engineer :	Bruce Sellars: b.sellars@gilkes.com: 250-483-3883
Date :	18 January 2011
Enquiry from :	Eri Boye: CRD Water
Site Name :	Humpback Water Hydroelectric Project
Country :	Canada

PROPOSAL

Gilbert Gilkes & Gordon pride themselves on providing the highest quality hydro turbine equipment designed to provide many years of trouble free operation. We have undertaken a preliminary analysis for the Humpback Water Hydroelectric Project. The design conditions were as specified in the RFEI documents dated September 3, 2008 issued by the CRD. The turbine selection is based on the following design conditions.

Please let me know if you would have revised these conditions.
- a gross head of 56 m
- a net head at 1300 l/s of 48 m
- a design flow of 1300 l/s

Gilkes is offering a 425G270 Francis turbine operating at 1200 rpm producing 561 kW at the design conditions. This turbine will operate from about 450 to 1450 l/s. The alternative of a Turgo impulse type turbine is not applicable as the Humpback project design requires pressure in the pipeline downstream of the turbine. Due to the extreme volatility in exchange rates, commodity prices and generator prices, this is a budget price. A firm price can be provided upon request based on an agreed scope of supply. In the budget price, we have included the inlet valve, turbine and generator. I have used electric actuators for the wicket gates and inlet valve. Hydraulic actuators can be supplied at an extra cost. I have not included the control system or any electrical equipment for the interconnection with the utility. The scope of supply and associated cost of this equipment varies significantly, and the selection is largely dependent on the owner's preference. Gilkes works with a number of highly qualified electrical engineering / installation firms and we can provide quotes for the controls and electrical equipment once we have more information on the scope of work. I have also included having a Gilkes engineer supervise the installation and commissioning. The civil work, site construction and installation will be by others. For your information, I have included some representative drawings for a 500 G270 in Quioch, Scotland and some drawings and photos of a 375 G190 in a water treatment plant in England.

Yours truly,

Bruce Sellars PEng

Hydro Sales Manager, North America

GILKES 2011 BUDGET OFFER:

EQUIPMENT
The Budget Price includes the following scope of supply:

Francis Turbine
1 off 425G270 Gilkes Francis Turbine
Horizontal arrangement
Electric actuated wicket gates
1 off Synchronous generator, 600V 3ph 60Hz
1 off Turbine shutoff valve
1 off Lot field services - supervision of installation / commissioning, testing and start up

BUDGET PRICE
$560,000 Canadian Dollars
The budget price includes packing and carriage CIF Victoria BC and is inclusive of import duty, but exclusive of HST, local sales tax or any other taxes.

ESTIMATED DELIVERY
10 to 12 months, ex works Kendal, England
Allow 4-6 weeks for shipping to US West Coast

GILKES 2004 BUDGET OFFER:

B U D G E T O F F E R
Quotation Ref : GI3005
Sales Engineer : Tom Askew
Date : 1st June, 2004
Enquiry from : Plan-It Management
Site Name : Humpback
Country : Canada
EQUIPMENT
1 off Gilkes spiral cased Francis turbine,
Horizontal
1 off Hydraulic pressure supply
1 off Induction generator, 415v/3ph/60Hz
1 off Turbine shutoff valve
1 off Pressure reducing Bypass Valve
1 off Controls and Switchgear
BUDGET PRICE
Budget Price for equipment specified above
£404,000 UK Pounds Sterling (or $1,000,000 Cdn at Current Exchange Rates)
Price includes packing and carriage CIF Vancouver, is inclusive of import duty but exclusive of local sales tax or any other taxes
ESTIMATED DELIVERY
40 working weeks, ex works Kendal, England
Allow 6 weeks for shipping.
TERMS AND CONDITIONS
Payment : A payment with order (10% of total contract value) and progress payments throughout the manufacturing period`will be required. General Terms and Conditions: Gilkes standard form L.91 copy available on request **VALIDITY** 180 days from the date of this offer.
TECHNICAL DATA
GILKES HORIZONTAL STYLE FRANCIS TURBINE
Model : 475G190
No. of units : 1
Mean diameter of runner : 475 mm (nominal)
Rated speed : 900 rpm
Maximum overspeed +/- 5% : 1385 rpm
Maximum continuous overspeed : 60 min in 24 hour period period
Inlet pipe nominal diameter : 600 mm
Runner material : Stainless Steel
Direction of rotation viewed : Anti clockwise from generator
Turbine runner supported via Anti-friction bearings
Guide vane mechanism operated by double acting oil hydraulic cylinder
DESIGN RATING
Rated net head : 50.7 m

Flow at rated head : 1.3 m3/s
Turbine design rating : 595 kW
Turbine Efficiency : 92 %
Setting Height (assuming altitude <1000masl) : 3.25m

TYPICAL INDUCTION GENERATOR SPECIFICATION

Power (continuous) : 595 kW
Rated speed : 900 rpm
Maximum overspeed +/- 5% : 1385 rpm
Maximum continuous overspeed : 60 min in 24 hour period period
Voltage : 415 volts
Frequency : 60 Hz
Power factor : 0.8
Nominal @full load
Insulation - Stator : Class 'F'
Rotor : Class 'F'
Stator temperature rise : Class 'F' (80 deg. C with
40 deg C ambient)
Exciter insulation : Class 'F'
Mounting details : Foot mounted
Enclosure standard : IP23
Bearing type : Anti-friction
Ambient temperature range : 0-40 deg C
Altitude : 1000 m.a.s.l. (maximum)
Voltage adjustment : Motorised
Stator temperature sensors : Yes
Bearing temperature : Yes

TYPICAL TURBINE INLET VALVE SPECIFICATION

Type : Double flanged butterfly valve
Design : Resilient sealing design
Flanges : BS 4504
Standard : Generally in accordance with BS 5155
Pressure rating : Normal working head of water 55 metres
Flange rating : PN16
Body : Ductile iron
Body seat : Stainless steel or elastomer
Disc : Ductile iron
Disc seal : Nitrile rubber
Shafts : Stainless steel
Bushes : Self lubricating type
Valve operator : Closure by gravity counterweight with oil hydraulic check
Opening by oil hydraulic cylinder

SLEEVE VALVE

Gilkes have also included for a 600mm Pratt Pressure reducing valve to act as a bypass valve for this project.

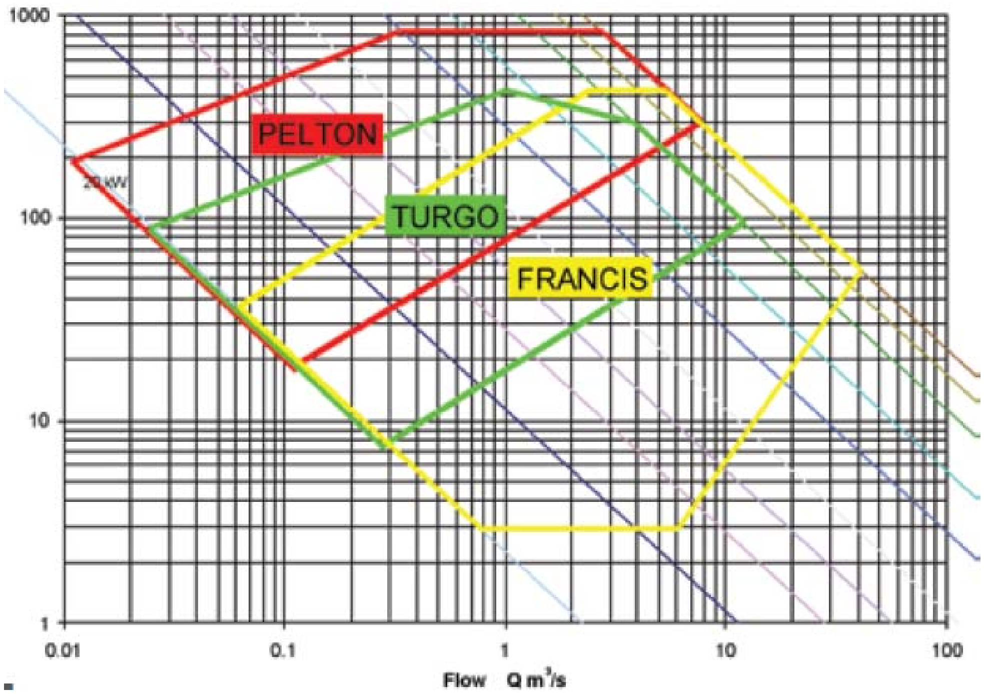
TYPICAL OIL HYDRAULIC PRESSURE SYSTEM SPECIFICATION

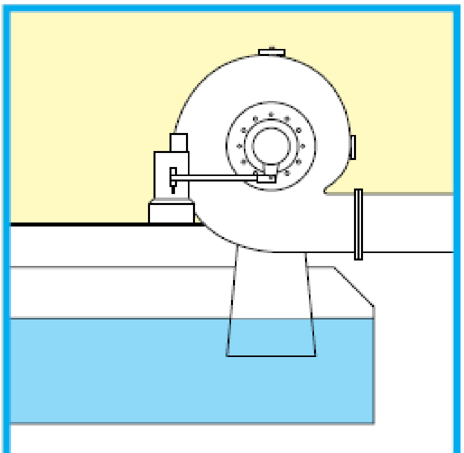
Free standing sump tank

Electric motor driven gear pump
Pressure relief valve and gauge
Filler, strainer, breather level gauge and thermometer
Flow/level indicating switches with alarm and trip contacts
Differential unloader valve
Bladder type accumulator system for auto shutdown on loss of AC supply
10 micron filtering system
Electro/Hydraulic servo valve module
For Main Inlet Valve
Electro hydraulic solenoid valve

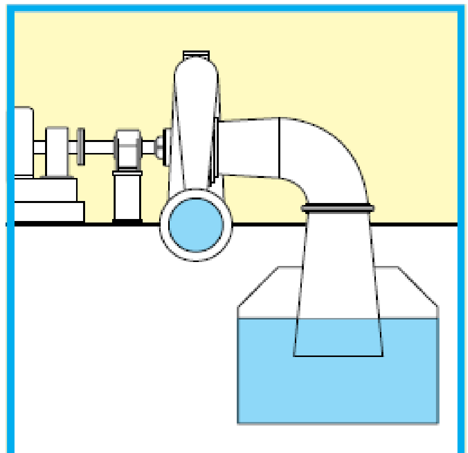
TYPICAL ELECTRICAL CONTROL AND SWITCHGEAR SPECIFICATION

Typical Panel Mounted Equipment
Electrical control, monitoring, protection and metering equipment
Automatic synchronising system for parallel operation
Station service system
PLC system for remote control, monitoring communications network by telemetry



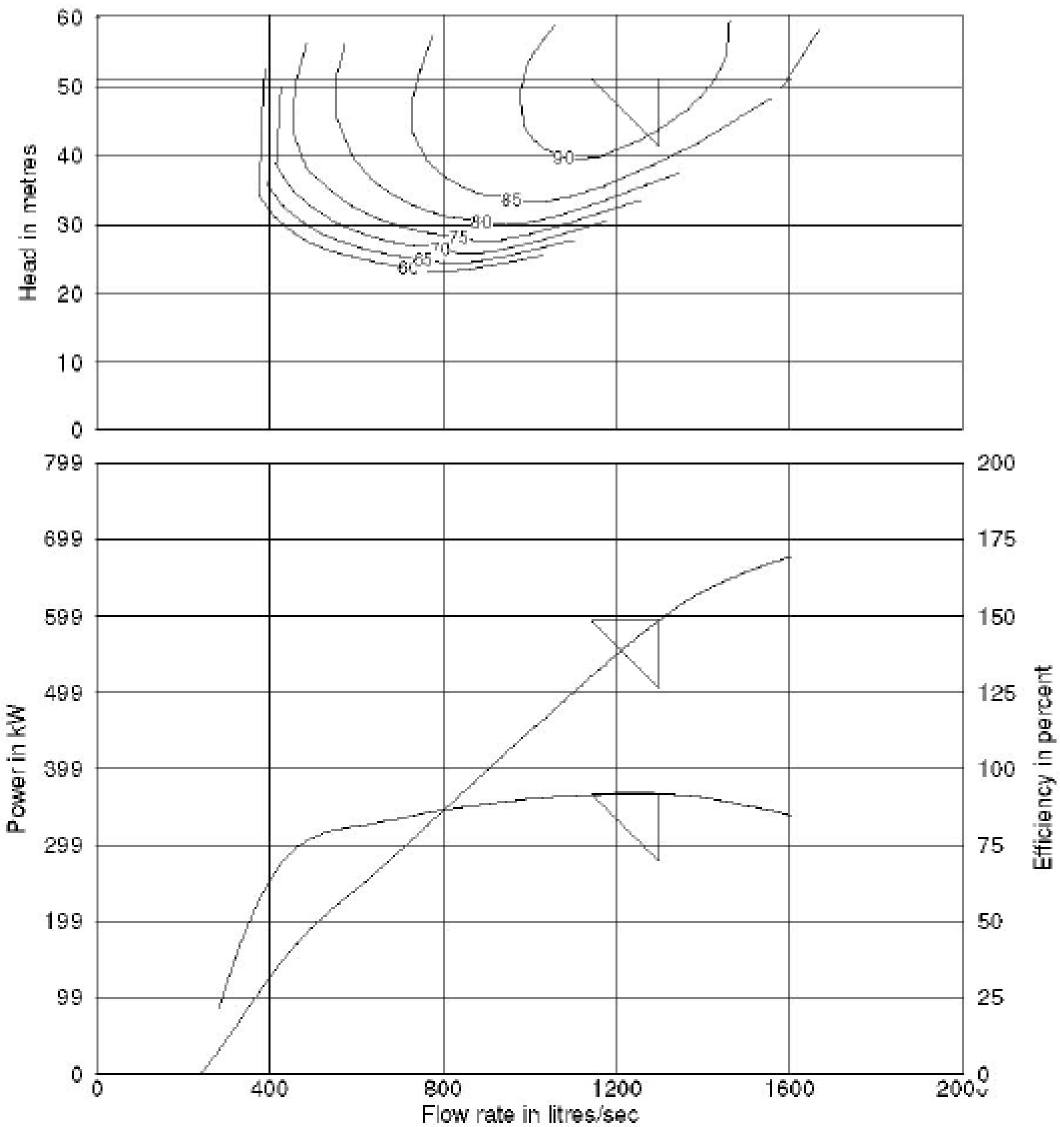


Horizontal Shaft-Spiral Case Arrangement



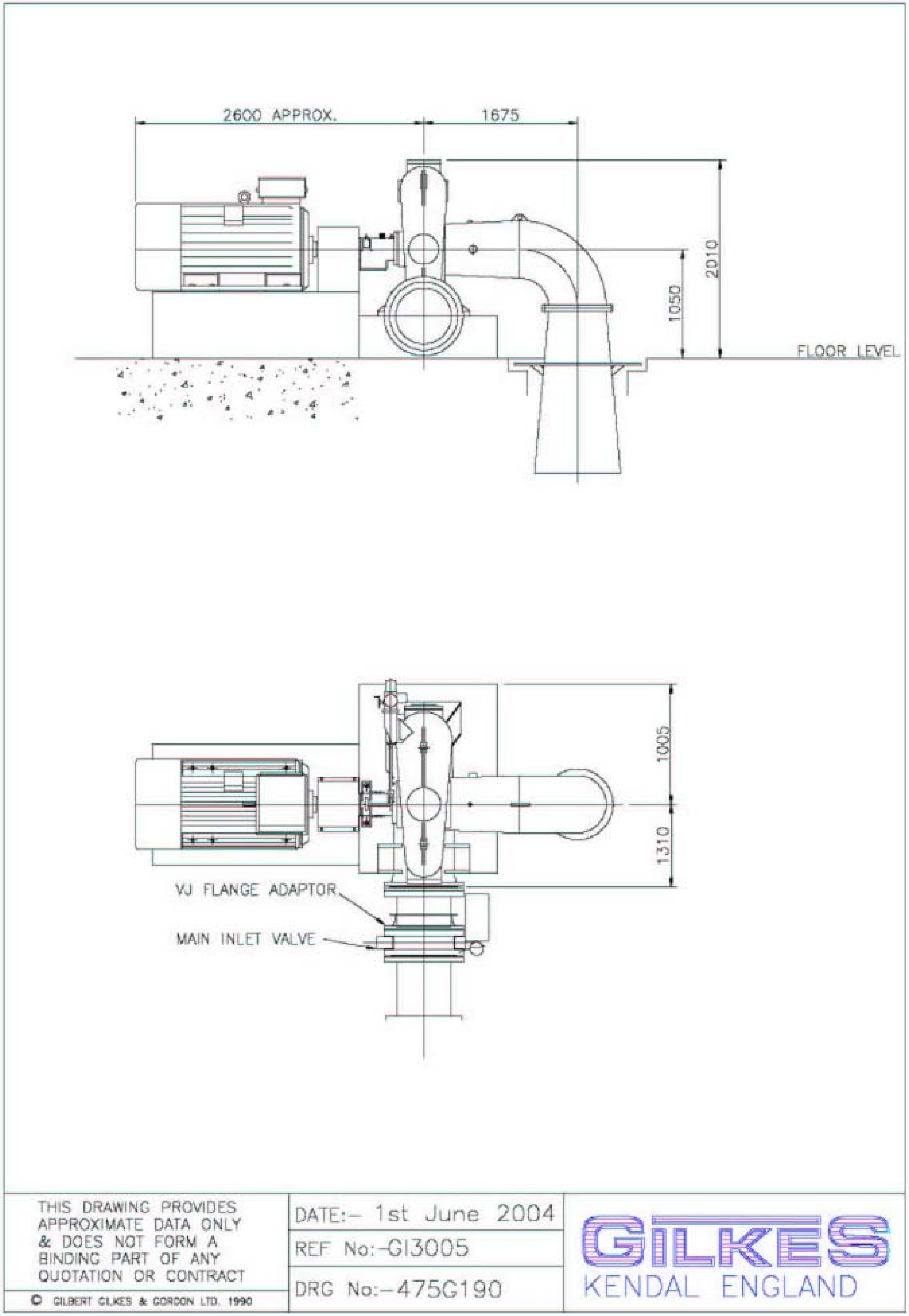
Horizontal Shaft-Spiral Cased Arrangement

GILKES Francis Turbine	475 G190 Speed 900 Rpm



Name	Head metres	Flow rate litres/sec	Power kW	Efficiency percent	Vent mm
Humpback	50.7	1300	595	92.0	24.4

Gilbert Gilkes and Gordon Ltd Kendal, Cumbria, UK. LA9 7BZ Tel: 01539 720028 Fax: 01539 732110	Approved 01/06/04	GI3005 Version Number 3


2600 APPROX.
1675
2010
1050
FLOOR LEVEL
1005
1310
VJ FLANGE ADAPTOR
MAIN INLET VALVE
THIS DRAWING PROVIDES APPROXIMATE DATA ONLY & DOES NOT FORM A BINDING PART OF ANY QUOTATION OR CONTRACT
© GILBERT GILKES & GORDON LTD. 1990
DATE:- 1st June 2004
REF No:-GI3005
DRG No:-475G190
GILKES
KENDAL ENGLAND

APPENDIX 3) THOMSON AND HOWE ENERGY DESIGN PLAN – HUMPBACK PRF

This option is for a 3 turbine system, and is used for price comparison.

The most cost effective Turbine/Generator units for the proposed Hydro Installation on the City of Victoria Humpback Creek PRV Station that has a net head of 157 feet (48 meters) and a flow of 780 liters per 75% of the time is a series of 8" x 10" turbine generator units which will each produce 80 kW. See Preliminary Layout Drawings MMD1435-463, 467 and 468. Alternatively the system could be designed such that the off-takes come up through the floor and straight into the units. The following is a budget cost for the recommended equipment that can be supplied by Thomson and Howe Energy Systems for a system with three 80 kW units having a total output of 240 kW at 480 volts three phase.

The equipment listed here and the initial drawing shows three units (for a total of 240 kW). Additional units could be added at the outset if the economics warrant it, or in later years as flows increase.

Generation Equipment Required Includes:

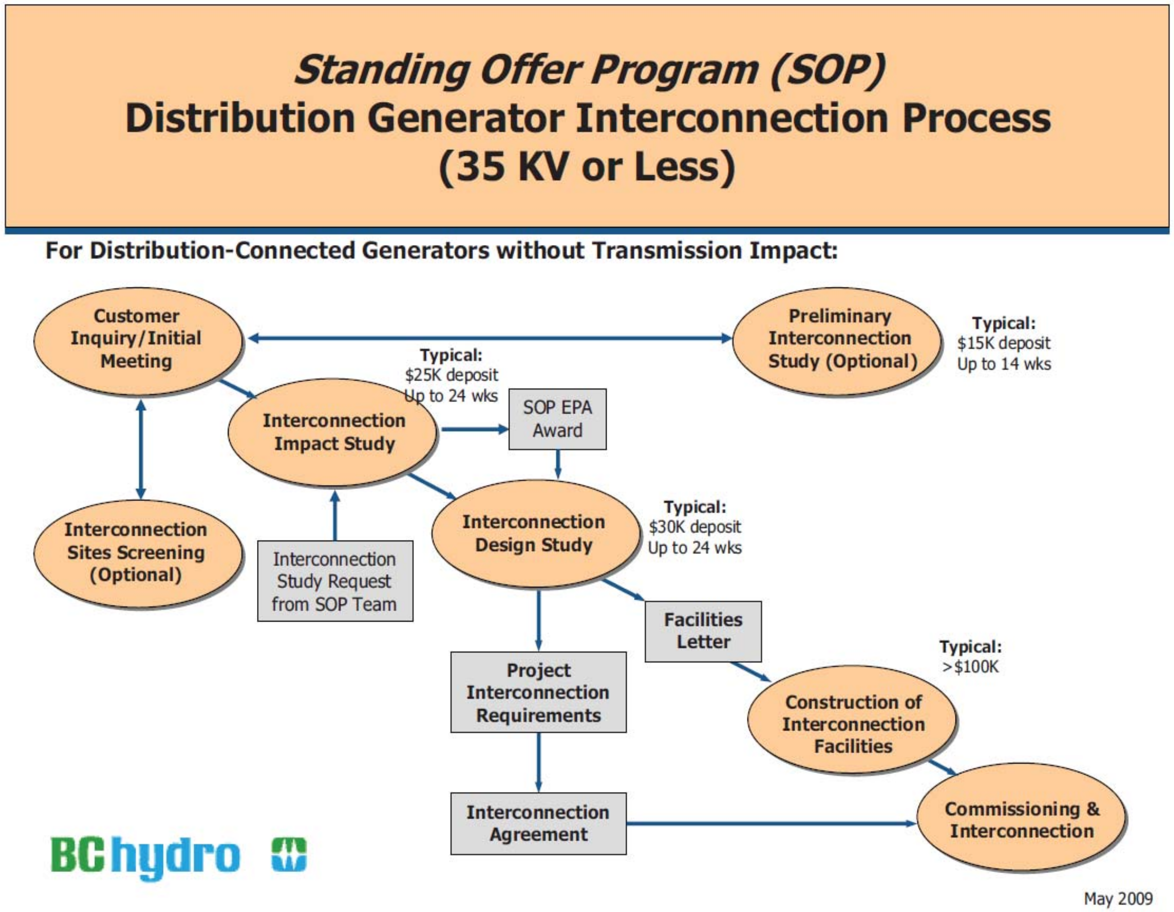
3 Pump/turbines size 8" x 10".
3 Induction Generators rated for 80 kW 480 volt 3 phase.
3 Welded Steel Bases for Turbine/Generator.
3 Generator couplings.
3 Coupling guards.
9 Keystone Butterfly Valves size 12".
3 Thomson and Howe Hydraulic Valve Actuators.
3 Thomson and Howe Actuator Control Panels.
3 Thomson and Howe Generator Switchgear Panels.
3 Thomson and Howe Generator Control Panels.
3 Welded Steel Turbine Inlet Reducers.
3 Welded steel Turbine discharge Reducers.
1 Custom turbine Controller – for downstream pressure
1 Engineering Design cost
Additional Components Required Include
6 Interconnection and Return Valving to Watermain (includes excavation)
1 Backfill and compact fill.
1 Prepare Powerhouse base – compact fill.
1 Powerhouse foundations
1 Powerhouse walls – concrete block construction
1 Powerhouse roof.
1 Crawl beams system
3 Turbine piping. (62 feet 12" pipe) $2200.00 each
1 Install turbines

1 Install Switchgear
1 500 KVA transformer (pad mount)
1 Install transformer

Total budget estimate for 240 kW Hydro Station (renewable generation equipment supply only) is approximately $200,000

Total budget estimate for 480 kW Hydro Station (renewable generation equipment supply only) is approximately $400,000

APPENDIX 4) BC HYDRO'S SOP PROCESS:



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