VALUE OF PUMPED STORAGE SYSTEMS IN BRITISH COLUMBIA

by

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The following individuals certify that they have read, and recommend to the Faculty of Graduate and Postdoctoral Studies for acceptance, the thesis entitled:

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Abstract

The need to establish electricity storage in British Columbia is brought by a regional and global shift towards the development of renewable electricity generation. The integration of renewable sources of power is challenging for system operators due to their inability to be dispatched. Energy storage enables a time lag between generation, transmission, and consumption. The unique characteristics of British Columbia, namely abundance of water and mountainous terrain, are well suited for the development of Pumped Hydro Storage (PHS).

The goal of this thesis is to investigate the value of the integration of a PHS plant in the BC Hydro system at a high level of planning. BC Hydro's Generalized Optimization Model, used for medium to long term planning, was modified to include PHS plants. The benefits of the PHS plant were considered as the incremental increase of the objective function of this optimization model compared to a base case. A method was developed to value PHS plants based on projected benefits and costs. A case study was performed using various configurations of PHS plants; including closed loop plants and one extension of an existing hydropower plant. Sensitivity analysis was performed to test the response of NPV over a number of inputs.

As the capacity and storage of the closed loop plants increased, the usage also increased. Benefits were not uniform across the set of water years reflecting the characteristics of each year's conditions and configuration of the BC Hydro system. The yearly benefit is highest for the extension of the existing hydropower plant. For the closed loop projects, the NPV is highest for the least amount of storage for each capacity. The NPV of all projects was most sensitive to the

variation of construction costs. Complete cost recovery of these plants using revenues consisting of trade revenues and increased overall system is unlikely. Additional sources of benefits and revenue streams should be identified and included in future studies of PHS projects. This research can be extended to projects with more certain estimates of characteristics and costs.

Lay Summary

The goal of this research is to investigate the value of electricity storage systems in British Columbia. The researcher enhanced an existing computer program at BC Hydro to model Pumped Hydro Storage plants. A method was developed to value these plants based on projected benefits and costs. The benefits were based on the results of the computer program with and without the Pumped Hydro Storage plant. They included additional electricity trade opportunities with Alberta and the United States, and increased resource efficiency of the BC hydro system. This method was applied to a case study of the BC Hydro system with various configurations of Pumped Hydro Storage plants.

Preface

The work presented in this research is carried out by the author Jonathan van Groll under the supervision of Dr. Ziad Shawwash in collaboration with the Planning and Licensing team within BC Hydro’s Generation Systems Operations department. The research project was fully funded by BC Hydro and by a CRD NSERC Grant to Dr. Shawwash.

The GOM model, discussed in Chapter 3 and 4, is an internal model used by BC Hydro engineers. Doug Robinson from BC Hydro’s Planning and Licensing team explained the workings of the GOM model and BC Hydro’s planning process, and was instrumental in this research. The enhancements of GOM were done in collaboration with Doug Robinson and Dr. Shawwash. The development of ancillary services in GOM was done in collaboration with Mr. Mehretab Tadesse. The author would like to acknowledge the Planning and Licensing team for access to data, modelling and IT support, and administration.

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List of Abbreviations

AB	Alberta
AESO	Alberta Electric System Operator
AMPL	A Mathematical Programming Language
AGC	Automatic Generation Control
BC	British Columbia
BCR	Benefit-Cost Ratio
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
cms	Cubic meters per second
CPI	Consumer Price Index
EPA	Electricity Purchasing Agreement
FERC	Federal Energy Regulatory Commission
GOM	Generalized Optimization Model
GIS	Geographic Information System
GW	Gigawatt
h	Hour
HPG	Hydro Power Generation
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRR	Internal Rate of Return

J	Joule
KP	Knight Piésold
kWh	Kilowatt Hour
Li-ion	Lithium ion
LP	Linear Programming
m	Meter
MW	Megawatt
MWh	Megawatt Hour
NPV	Net Present Value
P	Power
PHS	Pumped Hydroelectric Storage
QT	Turbine flow
s	Second
STOM	Short Term Optimization Model
US	United States
US DOE	United States Department of Energy
W	Watt

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I would like to thank everyone who supported me along the way.

My parents Calay and Raymond van Groll for supporting me in every decision I make. My mom for being the most kind and considerate person I know. I'd like to thank my dad for pushing me to do my Masters and for teaching me how to work efficiently with purpose.

This would not have been possible without my friends for putting up with my stubbornness over the years. Special shout out to Spencer Butt, Peter Craigen, Mike Webb, Nick McLeod and Alec Tory. We have had many adventures over the years which always allowed me to clear my head over the weekends and after work. Those late night discussions always put what I was doing into perspective and sharpened my focus. The support of my study group Jaime Perez de Villaamil, Michael Shynkaryk, Camilla Loughlin, Eli Riedl, Julie van de Valke, Dan Rohn, and Jen Goodale kept me aware of the importance of initiative and efficiency.

I'd like to acknowledge the vast support of my colleagues at BC. In particular I would like to thank Doug Robinson for his patience and ability to explain complex models in simple terms.

Thank you to Quentin Desreuxmaux, Mehretab Tadesse, and Abhishek Agrawal for your friendship and support. Our lunchtime walks through the nearby parks helped me clear my head.

Very special thanks to Ziad Shawwash for providing me this opportunity. His support and expertise were instrumental over this past year.

Dedication

This thesis is dedicated to my parents Calay and Raymond for their unwavering support for my entire life.

“To the best group in town”

Chapter 1: Introduction

This chapter provides the rationale for this research on Pumped Hydroelectric Storage (PHS). The first section discusses the importance of energy storage and why PHS is well suited for development in British Columbia. The second section lays out the goals and objectives of this thesis. Finally, the third section provides the reader with the organization of the thesis.

1.1 Overview

Energy storage systems are of increasing interest to utility scale electric energy suppliers and distributors around the world. There are growing opportunities for storage systems to provide unique services to the grid that have been recently created due to operational changes from the restructuring of the electric utility industry as well as advancements in energy storage technologies. A reliable, provincial-scale power system requires energy demand to be satisfied instantaneously. Energy storage increases system and market efficiency by facilitation a time lag between generation, transmission, and consumption. There are several types of energy storage including electric energy storage, oil in reserves and thermal storage. Electric energy storage allows for storage of electricity during periods of excess for use during periods of scarcity.

The integration of variable renewable energy has been challenging for system operators who must balance supply and demand. Figure 1 shows a daily snapshot of the California electricity market on a winter day. The majority of California relies on the California Independent System Operator (CAISO) to oversee and manage their electricity market. There are two major components of this figure: demand and generation supply shown on different scales. The day-ahead forecast, hour-ahead forecast, and actual demand curves show that significant adjustment must take place to ensure adequate supply in real time. This is despite the fact that the majority of market transactions take place in the day-ahead market. For example, the day-ahead forecasted demand between 2:00 AM and 4:00 AM was underestimated by approximately 5%, or about 1000 MW. This prompts the question: what would happen if no adjustment took place to manage 5% of the load in California for 2 hours? Unexpected blackouts can have many impacts including economic losses for businesses such as damaged equipment and unserved customers.

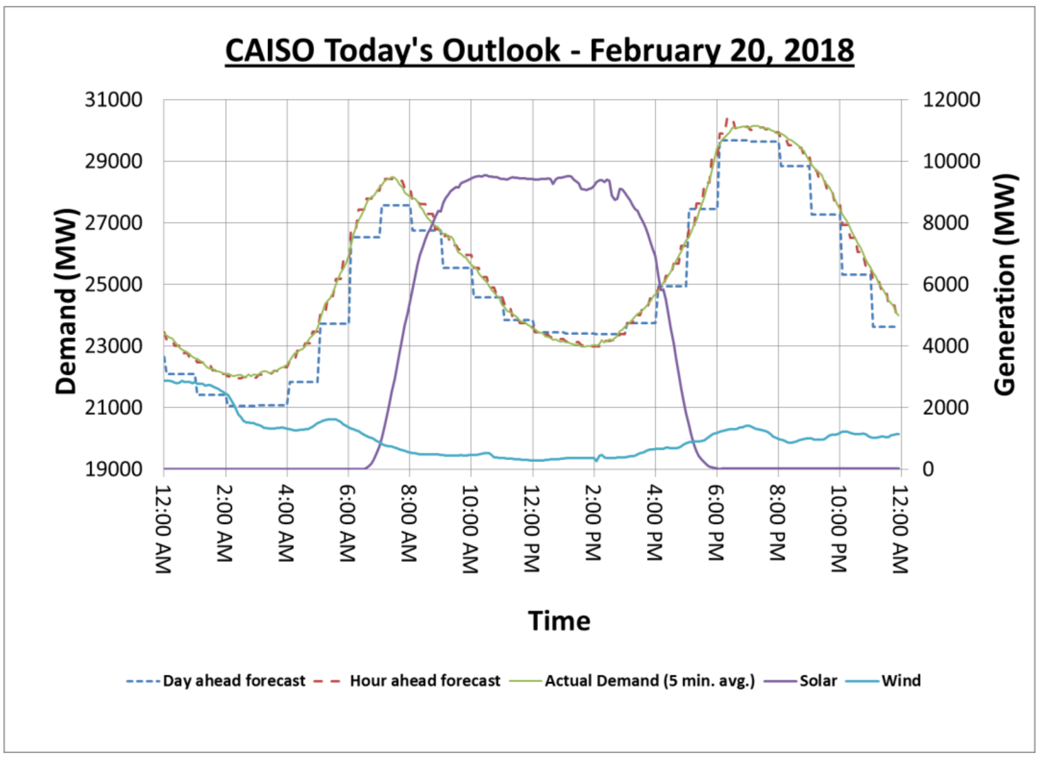

Figure 1 CAISO System Demand with Renewables on February 20, 2018

Source: Adapted from (CAISO, 2018)

The general pattern of demand throughout the day is predictable, peaking in the morning when people are getting up for work and in the evening when they are returning home. The other components of Figure 1 are the supply of solar and wind power, two of the components of the California energy supply. The supply of solar energy is somewhat predictable: it ramps up as the sun rises, peaks during the middle of the day, and ramps down as the sun sets. During winter months, the timing of the supply of solar energy is especially challenging for grid operators: ramping up while the morning peak demand ramps down; at its peak during the low demand middle of the day; and, ramping down when the evening peak demand ramps up. Wind energy is notoriously hard to predict and can be very sporadic, and is not always available when electricity is needed the most. Fortunately, California has begun to integrate electric energy storage technologies to provide flexibility. Batteries are one of many types of electricity storage used. The participation of battery storage is shown in Figure 2. On this day, batteries were used to meet the morning and evening peak, and absorb the excess electricity during the middle of the day.

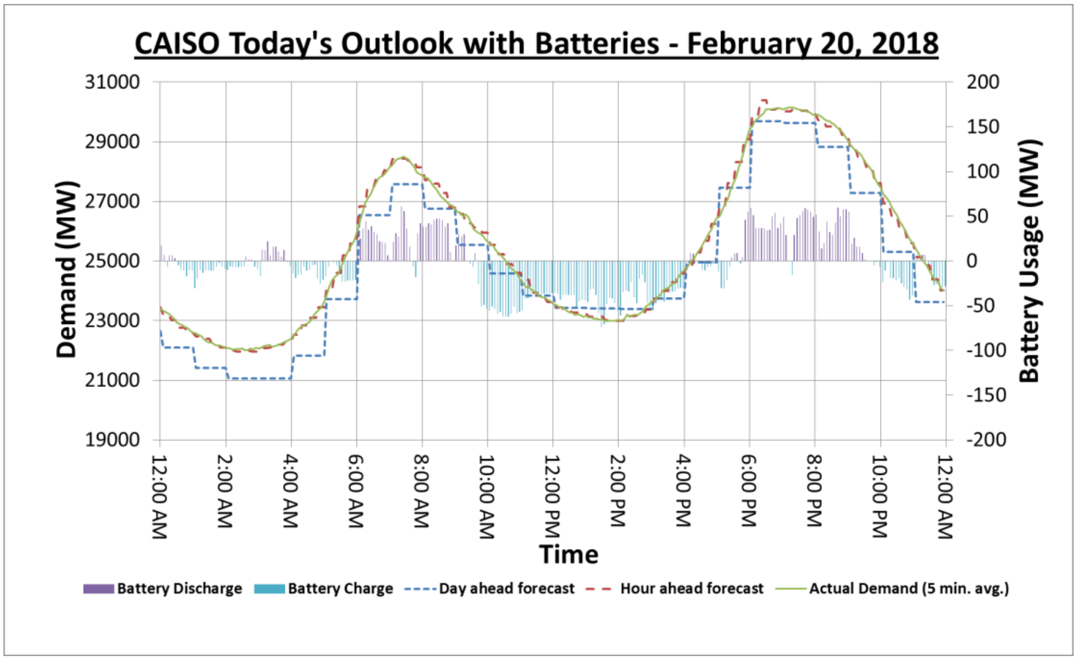

Figure 2 CAISO System Demand with Battery Usage on February 20, 2018

Source: Adapted from (CAISO, 2018)

Pumped Hydro Storage (PHS) is a well-established and commercially acceptable technology that can be used for utility scale electric energy storage. It is a modification of conventional hydropower technology that adds pumping functionality to store gravitational potential energy in the form of water in an upper reservoir. The unique topographic and geographic characteristics of British Columbia (BC), namely abundance of water and rugged mountainous terrain, are well suited for the development of PHS. Currently there are no PHS systems in BC and only one is found in Canada, the Sir Adam Beck Pump Generating Station owned by Ontario Power Generation.

The need to establish energy storage in BC is brought by a shift towards renewable energy generation. BC Hydro trades electricity through interties with Alberta and the western United

States (US) through one if its subsidiaries, Powerex. This means that the energy supply of these regions is also significant for BC. In addition, BC has procured Electricity Purchasing Agreements (EPAs) for the power from a significant amount of non-dispatchable sources of renewable energy consisting of wind and run-of-river projects from Independent Power Producers (IPPs). The bulk of IPP energy production and system inflows occurs during the spring snowmelt which is coincident with the lowest domestic load in BC as shown in Figure 3.

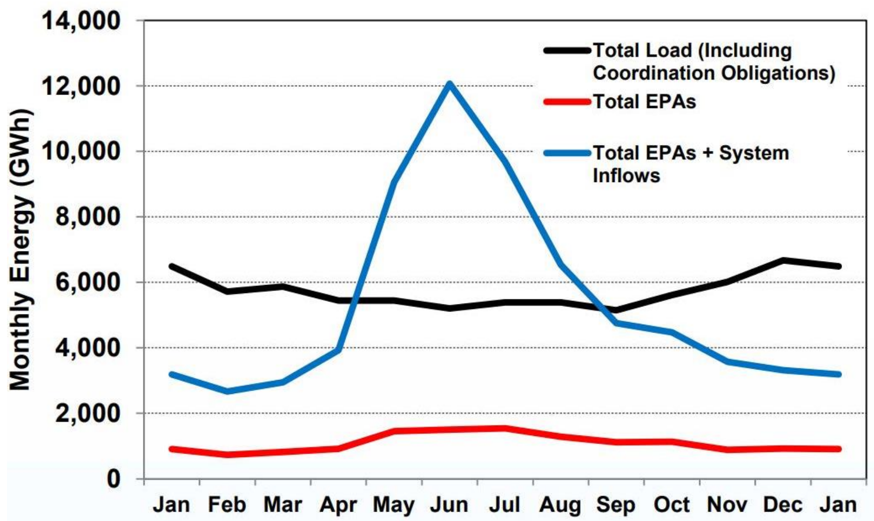

Figure 3 BC Hydro Load with IPP Generation

Source: (BC Hydro, 2015)

As discussed above, meeting new demand by integrating renewable sources of electricity generation is challenging for grid operators due to their inability to be dispatched. If electricity storage is well suited for the integration of non-dispatchable renewable energy, why is there such limited development in BC? One of the key recommendations from (National Hydropower Association's Pumped Storage Development Council, 2012) was to recognize the unique roles that PHS can play in different regions. This thesis explores methods of valuing the integration of PHS in BC Hydro's existing system. The rationale for exploring electricity storage ultimately stems from the ability to decouple energy supply from demand, and increase the efficiency of overall resource use.

1.2 Goals and Objectives

The goal of this thesis is to explore the value of the integration of PHS plants into BC Hydro's system at a high level of planning. It will investigate the benefits obtained through resource optimization and trade. In addition, it will examine the impacts that a PHS system will have on the operation of the BC Hydro system.

The objectives of this thesis are as follows:

- Accurately model and assess the impacts and benefits of the inclusion of pumped storage in the BC Hydro system;
- Create a PHS system valuation tool using discounted projected cash flows with inputs on projected cost and benefits derived from the optimization model; and
- Compare various PHS capacities (MW) and energy storage sizes (MWh) to assess if larger PHS capacity and energy storage size eventually have diminishing returns.

1.3 Organization of Thesis

This thesis consists of six chapters that show the reader why energy storage is important, why PHS is well suited for development in British Columbia and how it can be valued from a high level planning perspective. This chapter provides a rationale for this research on PHS by giving an overview of the problem, specific goals and objectives, and a structure of the thesis. Chapter 2 contains a literature review consisting of an overview of energy storage technology focusing on Pumped Hydroelectric Storage, an overview of energy markets explaining the difference between deregulated and vertically integrated utilities, current approaches for the valuation of energy storage systems and finally the optimization methods that will be useful for these valuations. Chapter 3 provides information about how PHS was modelled in the BC Hydro system as well as the methodology for the valuation analysis. Chapter 4 explains the data and assumptions used for the case study. Chapter 5 presents the results of applying the methodology to the case study. Chapter 6 highlights conclusions of this research as well as recommendations for future research work.

Chapter 2: Literature Review

This chapter provides background information for the reader. The first section provides an overview of energy storage technology including brief explanations of relative benefits and examples of projects. This section delves into the most details on PHS, the focus of this thesis. The second section consists of an overview of energy markets, with detailed analysis of about the markets of interest in BC. The next section discusses existing approaches and methodologies for the valuation of energy storage systems with a focus on PHS. The final section of this literature review discusses optimization in the context of energy systems, specifically with applications in hydroelectric systems.

2.1 Energy Storage Technologies

In developed countries around the world consumers expect electricity to be available at all times. The use of electricity has become ubiquitous in homes and a highly reliable supply is essential for working of modern and advanced economies. Due to the inability for electricity to be stored and because a lack of widespread demand side response from consumers, the electrical grid must be planned and operated so that demand and supply exactly match every second of every day in every location. In addition, consumers expect that the price of electricity is reasonably low and consistent. Energy storage systems are of increasing interest to utility scale energy distributors around the world. Energy storage enables increased system and market efficiency by allowing for a time lag between generation, transmission, and consumption.

There are many types of energy storage including mechanical, electrochemical, chemical, and thermal storage. Figure 4 shows examples of the types of energy storage with their relative maturity plotted against an estimate of risk adjusted cost.

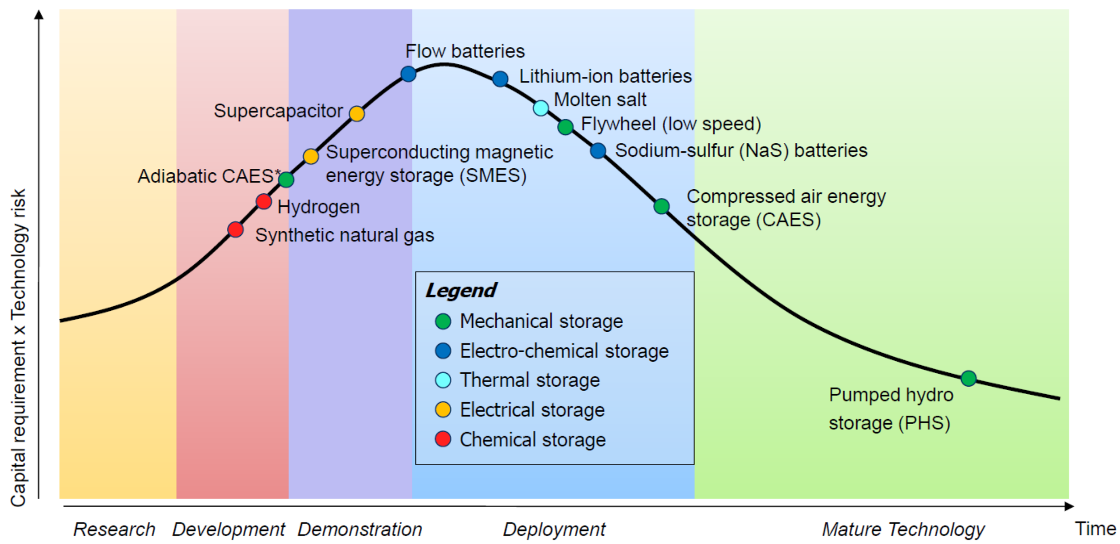

Figure 4: Relative Maturity and Cost of Energy Storage Technologies

Source (Decourt & Debarre, 2013)

The United States Department of Energy (US DOE) maintains a Global Energy Storage Database which tracks various types of energy storage projects at different stages of development around the world. A summary of the number of operational projects with their respective rated power in megawatts (MW) is shown in Table 1. Compared to other categories of energy storage, such as electrochemical projects, PHS currently has the highest rated power listed in the US DOE database.

Table 1: Global Energy Projects in Operation as of August 16, 2016

Technology Type	Projects	Rated Power (MW)
Electrochemical	987	3133
Pumped Hydro Storage	352	183800
Thermal Storage	206	3622
Electro-mechanical	70	2616
Hydrogen Storage	13	18
Liquid Air Energy Storage	2	5

Source: (Office of Electricity Delivery & Energy Reliability, 2016)

Two parameters are useful in comparing relative benefits of projects: capacity and storage. Capacity is a measure of how much energy can be delivered instantaneously by a generator and is measured in megawatts (MW). For example a 60 Watt (W) light bulb is using 60 Joules (J) every second that it is on. Storage is a measure of how much energy can be delivered by a system between when it is full to empty and is measured in megawatt hours (MWh). To clarify, 1 MWh represents provision of 1 MW for 1 hour and is the equivalent to 3.6×10^9 J. The storage parameter can also be expressed in terms of duration. Duration is a measure of how long the system can deliver the peak capacity and is measured in time, typically with hours as the unit. For example 1 MWh of storage can power a 60 W lightbulb for about 16,000 hours.

This thesis focuses on energy storage systems that store electricity rather than thermal energy, with a focus on application for operations for an electric utility. Thermal storage would have been considered had the application been directed towards residential or industrial systems. This section describes four of the most popular types of electricity storage: lithium-ion batteries, compressed air energy storage, flywheels, and PHS.

2.1.1 Lithium-ion batteries

Batteries are comprised of cells that contain two reactive materials that can undergo an electron transfer during a chemical reaction. Each cell contains two half-cells, which consist of a metal electrode submersed in a solution containing ions of the same metal. The half-cells are classified as either the anode if an oxidation reaction is occurring or the cathode if a reduction reaction is occurring (Decourt & Debarre, 2013). This electron transfer materializes as a flow of electrons which can be harnessed as electricity generation. Battery charging occurs by reversing the chemical reaction through reversing the flow of electrons between the terminals. The generating (discharging) and charging processes are illustrated in Figure 5 below. Lithium-ion batteries (Li-ion) are becoming very popular for consumer electric products and are being used to power hybrid and electric cars (Akhil, et al., 2013).

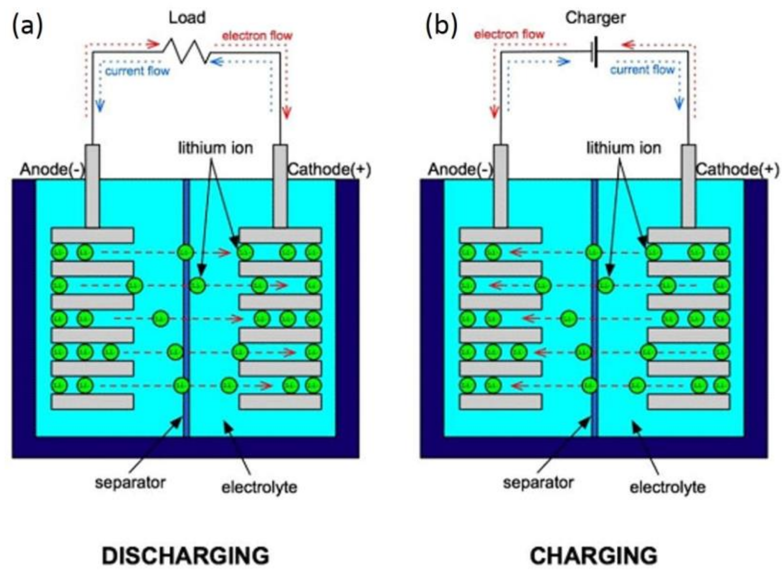

Figure 5: Discharging and Charging Cycle of a Lithium-ion Battery

Source: (The Rocking Char Battery (Lithium Ion Battery), 2013)

Li-ion batteries are becoming popular because of their high energy density and round trip efficiency of 80 to 93% (Akhil, et al., 2013). Their popularity is leading manufacturers to increase the scale of their production to drive down unit costs. One example of this is Tesla's Gigafactory 1 which is under construction in Nevada in the US. Tesla expects that vertically integrating production will reduce the production cost for their batteries (Battery cell production begins at Tesla Gigafactory, 2017). Although the production cost is expected to decrease, there remains significant uncertainty as to the magnitude of this decrease as shown in (Gambir, Hawkes, Schmidt, & Staffel, 2017). As of the publication of (Decourt & Debarre, 2013), there is a cumulative global installed capacity of 139 MW of Li-Ion batteries. In this report the expected lifetime of these projects is between 5 to 15 years, which is relatively short compared to other types of storage systems.

2.1.2 Flywheels

Flywheels use grid electricity to accelerate a rotor to a high speed where energy is stored as kinetic rotational energy. When electricity is needed the rotor is used to drive a generator. A typical layout of a flywheel is shown in Figure 6 with rotors positioned on magnetic bearings in a vacuum chamber. Flywheels are characterized as having a high power density and a low energy density. This means that flywheels can provide a large amount of power (MW) discharge for a short amount of time (MWh) relative to their volume. This energy can be stored with minimal standby friction losses because magnetic bearings are used and the unit is typically housed within a vacuum chamber. The wire to wire efficiency of flywheels is approximately 70 to 95% (Decourt & Debarre, 2013).

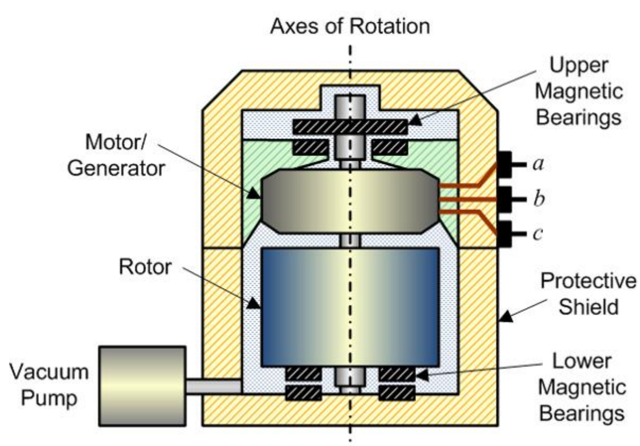

Figure 6: Typical Layout of a Flywheel

Source: (Molina, 2010)

Flywheels are typically used for frequency regulation services, a term that is defined in later sections, because of their ability to quickly charge and discharge resulting in millisecond scale response times. They are particularly well suited to provide these short bursts of energy because of their large cycle life that is in excess of 100, 000 full charge-discharge cycles (Akhil, et al., 2013). Flywheel technology is in use in a plant located in Stephentown, New York where 200 flywheels are used to provide 20 MW of frequency regulation. This plant is able to store 5 MWh over a span of 15 minutes and has a 4 second response time (Decourt & Debarre, 2013).

2.1.3 Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) works by powering a compressor using electricity from the grid or another source to compress ambient air and store it within a confined space. This process is shown in Figure 7 and is explained in detail in this section. The confined space can either be a natural feature such as salt caverns or an artificial space such a tank stored below water. The storage method is typically either constant volume or constant pressure. Constant volume storage has a chamber with rigid boundaries where the volume cannot substantially change but the pressure is variable. Underground salt caverns, which are popular vessels for CAES projects, are an example of a constant volume storage vessel. Constant pressure storage consists of a vessel that can vary in volume but remains at a fixed pressure. An application of constant pressure storage is positioning the vessel below a large column of water, i.e. the bottom of a lake, where hydrostatic pressure ensures a constant pressure inside the vessel. When electricity is needed the pressurized air is released to generate electricity by driving the compressor of a natural gas turbine during expansion.

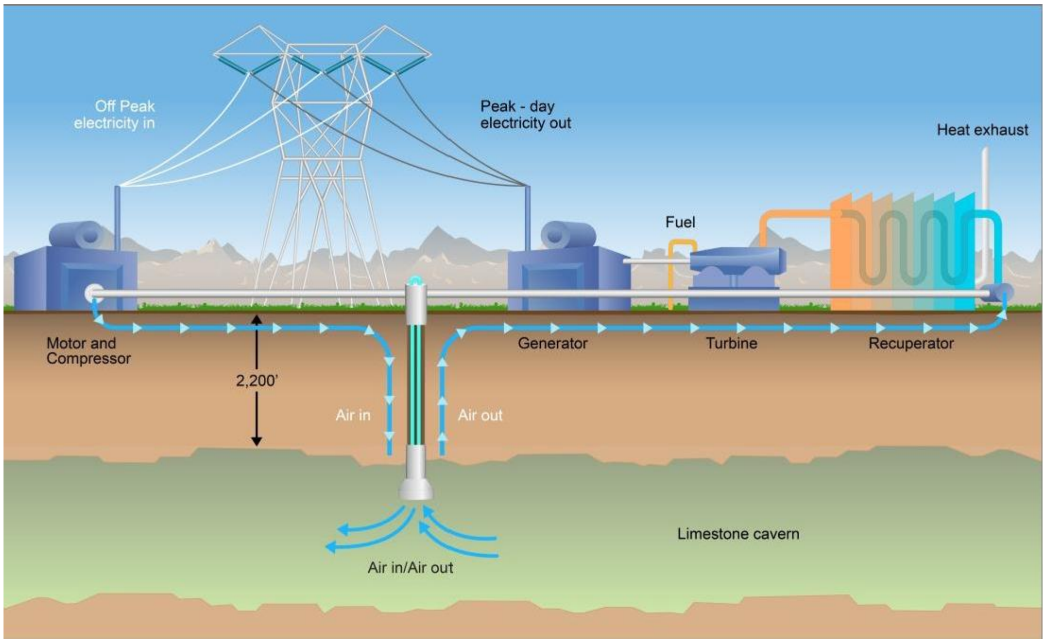

Figure 7: Typical Layout of a Compressed Air Energy Storage Plant

Source (Decourt & Debarre, 2013)

CAES projects are further categorized based on the thermodynamic process managing the heat generated in the air during compression. Currently it is not possible to store the air at the high temperatures reached during compression due to technical limitations of storage vessels (Decourt & Debarre, 2013). The three management methods in order of decreasing popularity are diabatic, adiabatic, and isothermal processes.

<u>Diabatic</u>

A diabatic process exchanges energy caused by temperature differences between a system and its surroundings. The vast majority of CAES projects are diabatic because they use intercoolers to dissipate the heat generated during compression. This dissipated heat is released into the atmosphere as waste. During the expansion process the air must be re-heated which is done using a natural gas burner. The efficiency of the conventional diabatic CAES is approximately 45 to 55% (Decourt & Debarre, 2013).

Adiabatic

An adiabatic process does not involve heat transfer in or out of a system. When applied to CAES technology heat generated during compression is stored and returned to the air during the expansion process. A successful deployment of this technology would eliminate the need to use natural gas to reheat the air upon expansion, reducing fossil fuel emissions while simultaneously increasing system efficiency. Adiabatic CAES is considered an advanced technology and is in its early stages of development. An adiabatic CAES project is being developed by RWE Power, an electric utility company, in Germany called ADELE which plans to use thermal energy storage to create an adiabatic CAES project with a wire to wire efficiency up to approximately 70% (RWE Power, 2010).

Isothermal

An isothermal process maintains a constant temperature during the compression and expansion processes. This requires a constant exchange of heat with the environment to maintain the same temperature while changing the pressure of the air. Rather than several stages of intercoolers, the heat transfer process occurs over a very small temperature difference which improves the efficiency (Energy Storage Association, n.d.). A perfectly isothermal process is a reversible process and has a theoretical efficiency of 100% (Crowley, 2015). This is not possible in practice and efficiencies of near-isothermal CAES projects are expected to be between 70 to 80% (Energy Storage Association, n.d.).

There are two CAES plants in commercial operation, both of which use a diabatic process as well as an underground cavern for storage. The first utility-scale CAES plant was commissioned in 1978 in Huntorf, Germany. It can produce a peak generation of 290 MW for 2 hours, storing 0.8 kWh of electricity and using 1.6 kWh of gas to produce 1 kWh of electricity The second CAES plant entered commercial operation in 1991 and is located in McIntosh, Alabama. It was originally designed to provide an output of 110 MW for 26 hours, storing 0.7 kWh of electricity and using 1.2 kWh of gas to produce 1 kWh of electricity. More information for both of these plants can be found in (Xing Luo, 2013).

The lifetime of these projects is expected to be approximately 20 to 30 years or longer as the commercial CAES plants mentioned above are still in operation. The advantages of CAES relative to other types of storage include the availability of operational history for two existing plants, flexible sizing of facilities, and the low cost per kWh (Decourt & Debarre, 2013). Disadvantages relative to other types of storage include a low efficiency compared to PHS, current reliance on natural gas for the expansion process for diabatic systems, and a constraint on available sites that could make use of existing geological formations (Decourt & Debarre, 2013).

2.1.4 Pumped Hydroelectric Storage

2.1.4.1 Introduction

The earliest PHS systems were developed in the 1890s in Switzerland, Austria, and Italy (Rehman, Al-Hadhrami, & Mahub Alam, 2015). PHS is a well-established and commercially viable system used for utility scale electricity storage. As shown in Table 1, there are 352 PHS plants operating or under construction with a combined capacity over 183 GW. PHS can be summarized as a modification of conventional hydropower technology to manage energy flows. It consists of two water-filled reservoirs at different elevations, connected by a tunnel or penstock. A simplified schematic of a PHS facility is shown in Figure 8. The key modification from conventional hydropower technology is the addition of a pumping unit that can be used to move water from the lower reservoir to the upper reservoir.

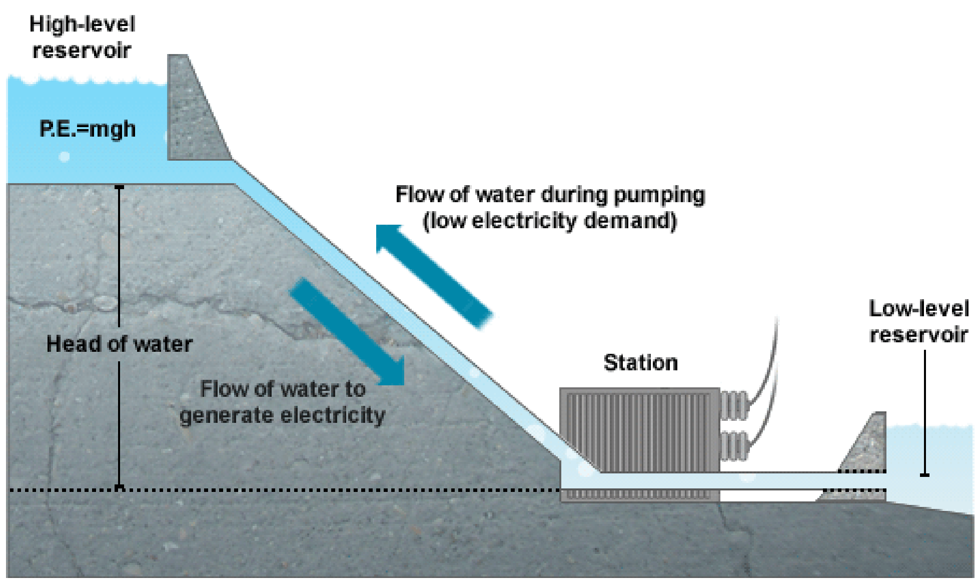

Figure 8: Schematic of a PHS System

Source (Generation of Electricity: Pumped Storage Hydroelectric Power Station, n.d.)

Energy is consumed from the electrical grid or other sources to power the pump and is stored as gravitational potential energy in the water lifted to in the upper reservoir. The amount of power that can be generated is proportional to the flow rate and the elevation difference between the upper and lower reservoirs (i.e. the head of water) as shown in Equation 1.

$$P = \rho g h Q \eta \frac{1\ MW}{10^6\ W}$$

Equation 1: Basic Power Equation

Where,

$g = 9.81\ m/s^2$

$\rho = 1000\ kg/m^3$

P = Power capacity (MW)

h = Gross head (m)

η = Overall efficiency in generation mode

Q = Design flow in generation mode (m^3/s)

The amount of energy that can be stored is proportional to the volume of water in the upper reservoir and the elevation difference between reservoirs as shown in Equation 2.

$$E = \rho g h V \eta$$

Equation 2: Basic Energy Equation

Where,

$g = 9.81\ m/s^2$

$\rho = 1000\ kg/m^3$

E = Energy stored (J)

h = Head (m)

η = Overall efficiency in generation mode

V = Volume of water in upper reservoir (m^3)

These two equations can be used to determine preliminary characteristics of a PHS system given site characteristics or system requirements. For example, a project with a flow capacity of 113 m^3/s with 100 m of head and a turbine efficiency of 90% would theoretically be able to provide 100 MW of power. In order to provide this power output for 6 hours continuously, the upper reservoir would need to be able to contain approximately 2.5 million m^3 of water. This is a rough approximation as the head will change as the upper reservoir is drawn down.

Beyond the management of forced outages of nuclear plants and transmission lines, off-peak electricity can be used to pump water up, which is then released to generate electricity when needed or when market prices are higher. This method of generating revenue is known as energy arbitrage. For arbitrage to be financially practical, the ratio of the cost of charging to discharging must exceed the round-trip efficiency (Ela, Botterud, Kirby, Milostan, Krad, & Koritarov, 2013). The round trip or grid to grid efficiency of PHS is approximately 70 to 85%, or 4.2 to 5.1 MWh of electricity is consumed to store 3.6 MWh (Barbour, Wilson, Radcliffe, Ding, & Li, 2016).

PHS projects are normally categorized as open or closed-loop based on the nature of their interconnection to existing waterways (Knight Piésold Consulting, 2013). Closed-loop projects are hydraulically closed where the only inflows and discharges from the system include seepage, evaporation, sublimation and direct precipitation. Open-loop projects are partially hydraulically open and can include other flow sources such as natural runoff.

2.1.4.2 Typical Pumped Storage Configurations

One of the benefits of PHS is that there is a wide range of capacity and storage sizes that can be constructed in terms of MW and MWh. The configuration in terms of MW and MWh's is ultimately limited by physical site constraints. If there are numerous sites to choose from with varying elevation differences between reservoirs and sizes of reservoirs that can be considered then technical constraints, such as the capacity of generators or pumps that can be fabricated, become the limiting factor. This section discusses the configurations of projects to get a sense of what a reasonable range would be suitable for BC. A reasonable range of projects is important to achieve one of the goals of this thesis: determining if there is a trade-off between capacity, storage and cost. The general areas of reference will include global PHS development and studies specific to BC.

Global Pumped Storage

As referenced earlier, the US Department of Energy maintains a Global Energy Storage Database that tracks the capacity and storage size of energy storage projects. This data can be filtered to specific technologies at varying stages of development. For the purposes of this analysis the database was filtered to only include PHS projects with an "Operational" status with durations greater than 1 hour. As of 2017 there are 78 projects that fit these criteria, most of which are in mountainous regions of Europe and the Eastern US. There are likely more projects that fit their criteria; however their characteristics were not available on the Global Energy Storage Database. Histograms of the capacity, storage, and duration are shown in Figure 9, Figure 10, and Figure 11 respectively. A summary of basic statistics for these projects can be found in Table 2.

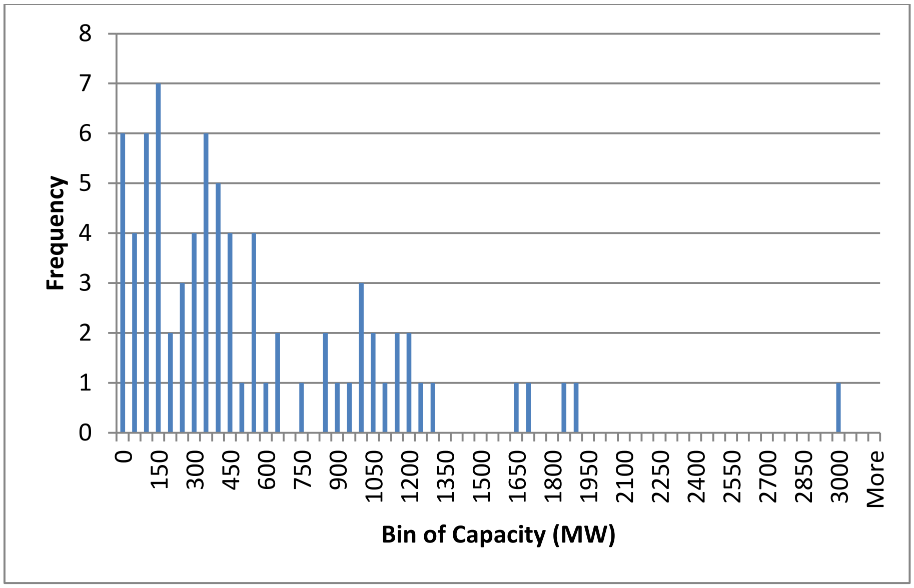

Figure 9: Histogram of Capacity

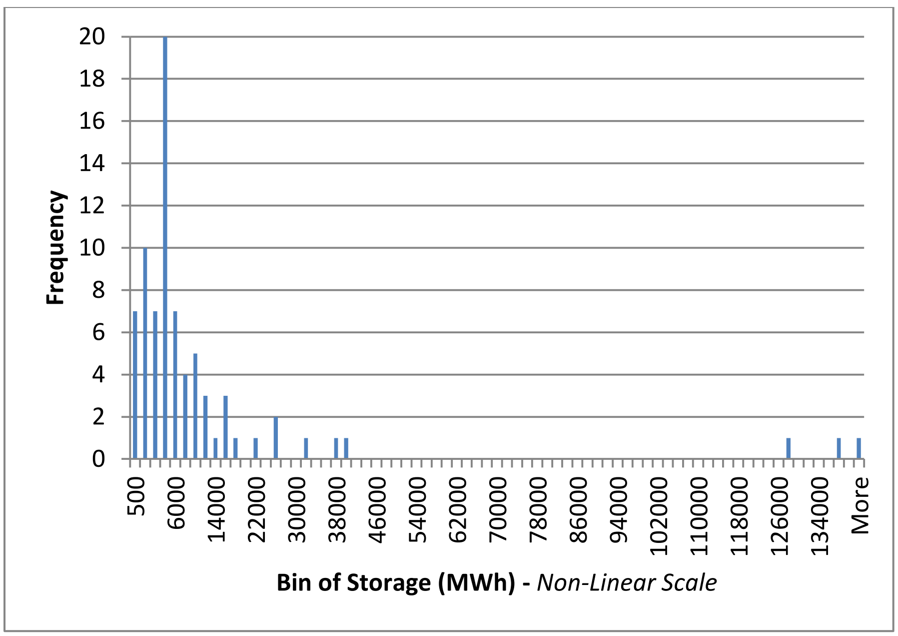

Figure 10: Histogram of Storage

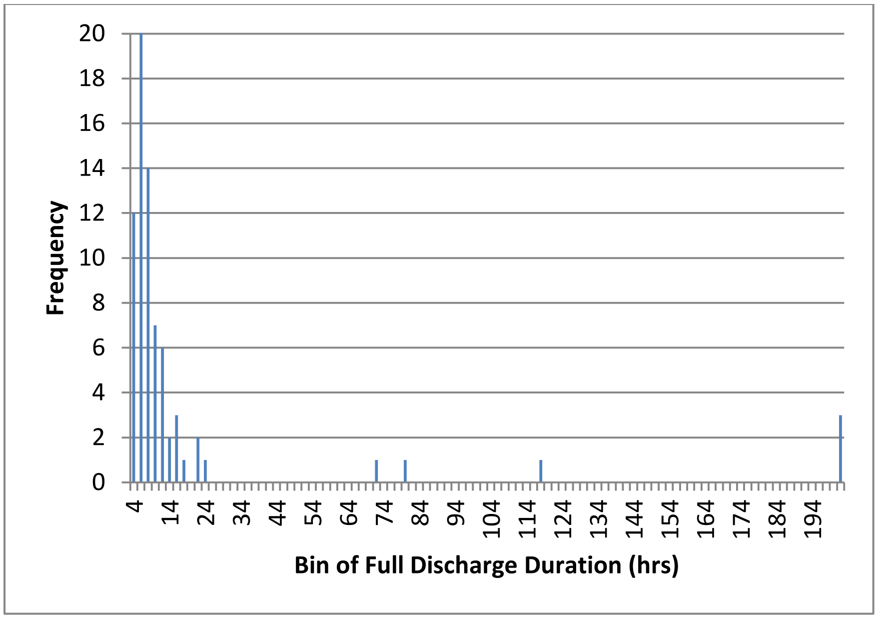

Figure 11: Histogram of Duration

Table 2: Statistics of Global Pumped Storage Projects

	Minimum	**Maximum**	**Average**	**Mode**	**Median**
Capacity (MW)	0.006	3003	580	600	410
Storage (MWh)	0.036	973102	22000	2400	3500
Duration (hrs)	2.5	14310	212	6	7

<u>Studies Specific to BC</u>

Included in BC Hydro's 2013 Integrated Resource Plan (IRP) were three reports regarding PHS in BC prepared by external consultants. PHS was considered alongside natural gas-fired generation as one of the supply-side capacity resource options.

Hatch prepared a preliminary study and cost estimate for the addition of PHS at Mica Dam (Hatch, 2010). An advantage of this site is the large storage reservoir located upstream of Mica Dam named Kinbasket Lake. The reservoir has a live storage volume of 15 billion cubic meters of water and is drawn down annually. Immediately downstream and impounded by the Revelstoke Dam is Revelstoke Lake, which has a lower storage volume of about 3 billion cubic meters. During the late spring freshet period power rates are typically low and there are high inflows into Revelstoke Lake due to snowmelt. Since Revelstoke Lake is comparatively small, water is being used to generate low value power. Adding PHS to Mica Dam would allow the operator to pump this water into Kinbasket Lake to be used during more opportune market conditions. Rather than using the water to generate power once during low value periods, it can be stored and generated at higher value periods through the Mica Dam and then at the Revelstoke Dam. Initially two locations at the dam were considered: an extension to the existing powerhouse and on the left side of the dam in the spillway area. It was decided that the left side would be a better choice due to the technical difficulties of construction adjacent to existing generating units. The preliminary study includes the economic and technical specifications for two reversible 250 MW units. The cost is relatively low given the amount of infrastructure already constructed at the site, i.e. transmission lines and reservoirs. Assuming the reversible pump turbines are the only units being used and that the 500 MW is generated using approximately 300 m^3/s of water, the duration for this project is just less than 14,000 hours and storage is just less than 7,000 GWh. It should be noted that the plant would never actually be run using just the reversible turbines, this is just used to compare to other projects.

Another consultant, Knight Piésold (KP), prepared two reports containing screening assessments for PHS potential in two areas in BC: Vancouver Island and the Lower Mainland; and the North Coast Region (Knight Piésold Consulting, 2013). The question that KP addressed in their reports was if there are potential viable greenfield sites, lacking constraints imposed by prior work, in the above mentioned areas that are economically viable. For the Vancouver Island and Lower Mainland report, the capacity and storage requirements for potential sites were 500 MW and 3000 MWh or 1000 MW and 6000 MWh. In both of these cases the duration requirement was 6 hours at maximum generation capacity. For the North Coast Region report the capacity requirements for potential sites were also 500 and 1000 MW but the storage requirements split the potential sites into two sets based on duration requirements of 16 hours or 48 hours. Overal there was four types of potential projects: 500 MW/8000 MWh, 500 MW/24000 MWh, 1000 MW/16000 MWh and 1000 MW/48000 MWh. In order to complete this screening, sites were selected based on a GIS tool that characterized sites based on their gross head, storage volume, embankment height, reservoir area, length of waterway, etc. Cost estimates were developed using a cost template based on KP's previous experience with PHS projects. These cost estimates did not include transmission, interconnection or site access, however these costs were deemed important to the economic viability of the site. The study screened potential freshwater, saltwater, and underground mine sites. The design lifetime of projects contained in this report was 70 years. Recommendations at the end of these reports suggested that a system-wide study of BC Hydro's grid should be undertaken in order to determine the benefits and impacts of integrating PHS. In addition it was suggested that the ideal characteristics of a PHS facility, i.e. capacity and storage, can be determined from such a study in order to improve electricity export opportunities and firm renewable power sources.

2.1.4.3 Current Development and Market Trends

Although the majority of PHS projects were developed in the 1960s to complement larger power projects such as nuclear plants, changing needs and technology are driving new development. As of January 2017, the US Federal Energy Regulatory Commission has issued over 14 GW of preliminary permits for PHS projects (FERC, 2017). Advanced PHS, comprised of ternary and variable speed units, are becoming more popular compared to the less flexible, conventional fixed-speed units (Argonne National Library, 2014). There has also been recent interest in developing PHS projects with non-traditional reservoirs. These include the ocean as a lower reservoir as well as using retired mining caverns and open-pits. There is one PHS project that used the ocean as a lower reservoir in Japan. The Okinawa Yanbaru Seawater Pumped Storage Power Station is a 30 MW open-loop PHS project that was commissioned in 1999 (Okinawa Yanbaru Seawater Pumped Storage Power Station, 2014).

In addition to energy arbitrage there are additional potential sources of benefits from the operation of PHS systems, including ancillary services and increased overall system flexibility.

Regulatory bodies are considering their role in PHS development; the National Hydropower Association (NHA) Pumped Storage Development Council issued a report outlining the challenges and opportunities for new PHS development in the US (National Hydropower Association's Pumped Storage Development Council, 2012). In summary, the recommendations of this report were to establish a streamlined licensing process for closed-loop PHS, and to facilitate investment by improving the recognition of the benefits and services PHS can provide within markets (National Hydropower Association's Pumped Storage Development Council, 2012). The US government is currently examining the possibility of allowing development of non-federal pumped storage projects on Bureau of Reclamation facilities (Harris, 2017). In 2017, the US congress directed the Federal Energy Regulatory Commission to investigate the feasibility of a 2-year licensing process for closed-loop pumped storage projects (Hydropower Regulatory Efficiency Act of 2013, 2017). One of the largest barriers to PHS development is the extensive permitting and application phase, which can take three to five years (National Hydropower Association's Pumped Storage Development Council, 2012).

In (Deane, Gallachóir, & McKeogh, 2010) a review was conducted on the current global state of PHS. It draws on publicly available information from utilities, government bodies, and electricity regulators. This paper provides a detailed review of PHS systems, examining the development of PHS systems around the world to determine drivers and estimate costs of existing and proposed projects. A distinction is made between pure pumped storage project and pump-back storage projects which is akin to closed and open loop projects. This paper suggests that successful candidate sites for PHS projects are characterized by specific conditions including favorable topography, hydrologic and geotechnical conditions, and access to existing transmission networks. These conditions are not present in every country and the development of PHS has been focused in the USA, Japan and alpine regions of Europe. These regions have similar geographic characteristics as BC, where power is predominantly generated by conventional hydroelectric plants. When PHS systems were first being developed their purpose was to supply energy during periods of high demand and optimize the efficiency of base load plants by allowing them to run during periods of low demands. This paper suggests that there is a degree of correlation between installed nuclear power capacity and PHS development. It also suggests that renewed interest in PHS is likely a result of increasing development of intermittent generating sources such as solar and wind brought by government and regional targets. This is because these sources are intermittent, non-dispatchable and uncertain while system operators are required to balance supply and demand. This need to balance these sources combined with the increased liberalization of electricity markets drives the demand for system reserves and ancillary services.

PHS projects tend to have a high capital dependent on site conditions, storage quantity, and generating capacity. The authors of this paper observed a general linear trend when comparing installed capacity and capital cost (Deane, Gallachóir, & McKeogh, 2010). There is, however, a lack of historic data that characterizes capital cost based on site conditions or storage quantity. This lack of historic data leads to the use of this cost per installed MW to be a benchmark for estimating capital cost. A trend of newer projects experiencing higher capital cost is observed attributed to higher licensing costs and increasing complexity of PHS technology. The review of proposed and historic projects show that capital cost can be decreased by enhancing existing hydroelectric projects rather than building a completely new PHS. Although revenue generation from PHS systems is not quantified in this paper, it briefly discusses potential sources of remuneration. Sources of remuneration in open electricity markets include ancillary service payments, capacity payments, and electricity trading. Electricity trading is reliant on price volatility, such as on and off peak prices, to compensate for energy losses. This paper is useful in that it acknowledges certain regions are more likely to develop PHS and that the reasons for developing PHS are evolving. There is value in looking at past projects for estimating the capital cost of PHS but care must be taken as the changes, such as increased regulatory processes can cause these costs to be higher on new projects. Using cost per installed MW appears to be the standard for comparing projects but projects can vary significantly due to specific geographies and storage sizes.

2.2 Energy Markets

2.2.1 Overview of Markets

A reliable power system requires energy demand to be satisfied at any given time. Practically, power must be available whenever someone decides to turn on a light. There are two requirements that must be constantly and perfectly satisfied to maintain stability and reliability (Kirby, 2007). First, as alluded to above, power system operators must maintain a constant balance between load and generation. Second, power flows through individual transmission lines must be managed to operate within their constraints.

Power systems have evolved as a result of increasing interconnectivity and popularity of open markets. Power systems consist of three main components: generation, transmission, and distribution. In the case of vertically integrated utilities, such as BC Hydro, these fields are bundled together and controlled by one entity responsible for the power system in one area (Kirby, 2007). In 1996, FERC implemented *Order 888* in the US which promotes open access to transmission networks in order to boost competition in wholesale electricity markets (Conejo, Carrión, & Morales, 2010). This order resulted in a restructuring process that ultimately unbundled the package of services that were originally provided by the vertically integrated utilities. Electricity markets typically have two components: wholesale and retail. The wholesale market involves electricity transactions between utilities and traders, and the retail market involves the actual sale of electricity to consumers (Conejo, Carrión, & Morales, 2010).

The dispatch of generation resources is done differently for vertically integrated utilities and restructured markets (Conejo, Carrión, & Morales, 2010). In a vertically integrated utility the marginal cost of power is optimized as an economic dispatch (Kirby, 2007). In a restructured market hourly and sub-hourly markets are cleared based on energy bid prices (Kirby, 2007). These concepts will be further explained in the next two sections. Although BC Hydro is a vertically integrated utility, it participates in deregulated markets using imports and exports through transmission interconnections with Alberta and the US (BC Hydro, 2000). These markets will be briefly discussed due to their relevance to BC Hydro. As will be explained later in this thesis, long term planning of resources satisfies domestic load at least cost and maximizes trade benefits using these interconnections.

In a general sense there are two main markets: capacity and energy. Capacity markets have a longer time horizon and exist to ensure adequate supply of electricity in future years by incentivizing private companies to develop power projects (Kirby, 2007). Within the energy market, electricity demand is satisfied using two sub-markets; the day-ahead market and the real-time markets (Berrada, Loudiyi, & Zorkani, 2016). Schedules for the supply and demand of electricity one day in advance are created in the day-ahead market. The real-time market is a spot market where electricity can be purchased or sold to balance the difference in real-time quantities with forecasted quantities scheduled using the day-ahead market.

These markets can be further categorized based on what is being provided. The physical energy that is being traded is considered as being traded within the energy market. There are additional services that are required to ensure the stability and reliability of the grid; these are known as ancillary services (Kirby, 2007). Ancillary services are defined by the Federal Energy Regulatory Commission (FERC) as “Those services necessary to support the transmission of power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system”. This thesis will focus on just two of the market arenas in which BC Hydro participates in: Alberta and California. It is important to note that BC Hydro does not only participate in the California market in the US, it is being highlighted due to its structure and availability of information. Some of the trading partners use bilateral agreements rather than open markets, the content of which is confidential.

2.2.1.1 Alberta

Deregulation of the electricity market in Alberta began when the Power Pool of Alberta was created in 1996 to dispatch real-time energy across Alberta (Guide to understanding Alberta's electricity market, n.d.). It was created to encourage competition in the electricity generation sector to increase overall efficiency. Energy dispatched in this market was given a single equilibrium price determined using the economic merit order. The merit order is a process by which sources of electrical generation are listed in an ascending order of price based on their short-run marginal cost of production. The lowest cost generation sources that meet the forecasted demand are dispatched to serve the electrical load. The highest cost source that is dispatched creates the equilibrium price, or market clearing price, paid to the other sources that were dispatched. Power Purchasing Agreements were introduced in 2001, enabling owners of generation sources to continue to own and operate their facilities but auctioning off the rights to the energy to new buyers. The provincial power grid is now operated and managed by the Alberta Independent System Operator (AESO). The AESO was formed as a result of the merger of the Transmission Administrator and the Power Pool of Alberta in 2003. It has a mandate to act in the public interest and is not allowed to own any transmission, distribution or generation assets.

The supply of electricity in Alberta between 2012 and 2016 is shown in Figure 12 below. As shown, the supply is primarily comprised of fossil-fuel based sources including coal and cogeneration plants. Alberta plans to encourage the development of renewable energy generation in the coming years. As outlined in the Renewable Electricity Act, they plan on procuring 5000 MW of renewable electricity by 2030 (Province of Alberta, 2016). This renewable energy is defined as "an energy resource that occurs naturally and can be replenished or renewed within a human lifespan, including, but not limited to, (i) moving water, (ii) wind, (iii) heat from the earth, (iv) sunlight, and (v) sustainable biomass" (Province of Alberta, 2016). As Alberta transitions towards their renewable energy target, BC can play a role in supporting their grid using transmission interconnections. PHS could be a useful resource for BC Hydro to help Alberta achieve their development goals.

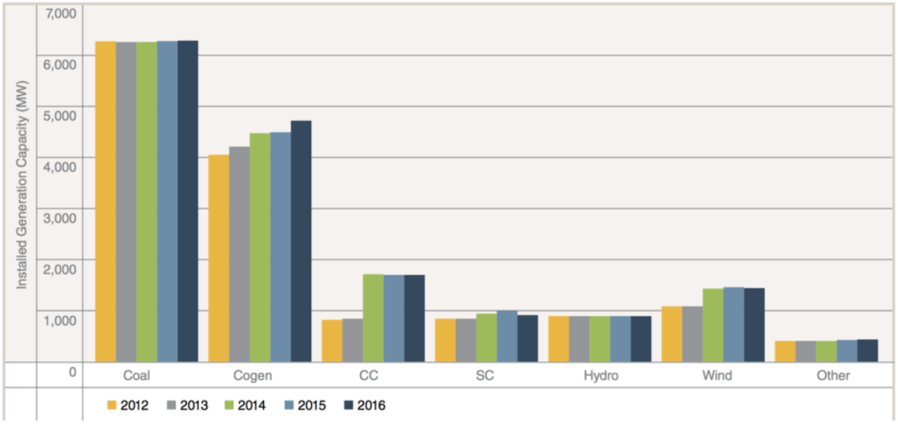

Figure 12: Annual Generation Capacity by Type

Source: (AESO 2016 Annual Market Statistics, 2016)

In addition to plans for incorporating more renewables, Alberta is also planning on transitioning to a capacity market (Alberta Electric System Operator). This is a transition away from generators having to recover their costs purely from energy sales. The capacity market pays generators for having the ability to make power available, as well as for the actual energy produced (Kirby, 2007). It is unclear how BC Hydro will be able to participate in this market, but could provide an additional cost recovery mechanism for electricity storage systems that would otherwise have to recover their cost using the energy market.

2.2.1.2 California

The operation of California's power system, transmission network, and electricity market is overseen by the California Independent System Operator (CAISO). CAISO is an independent grid operator that was created in 1998 following the restructuring of the California electricity market. California is a summer peaking region, meaning that electrical loads are generally highest in the summer months when the high temperatures cause use of air conditioners. BC is a winter peaking region with generally lower temperatures in the winter causing increased use of heating. This mismatch of peak loads and the presence of transmission connection led to the formation of a trading relationship (BC Hydro, 2000). The California energy market is also cleared using the merit order described in the above section. Solar power has become more popular due to the abundance of sunlight in California as shown in Figure 13. Sources of generation without fuel costs, such as wind and solar, significantly affect the clearing price when they are available (California ISO, 2017) . This is most apparent during the middle of the day when solar power is most available but the load is low. These circumstances can lead to periods of extremely low or even negative prices (AESO). Solar power plant owners can still earn revenue with negative prices because of renewable energy credits. If BC Hydro can reduce their generation, they can import this inexpensive electricity to use to serve load. Electricity storage would allow them to import this electricity even if it is not needed at the time and ultimately help California integrate more renewables in their generation portfolio. Ramping problems can also be reduced using electricity storage.

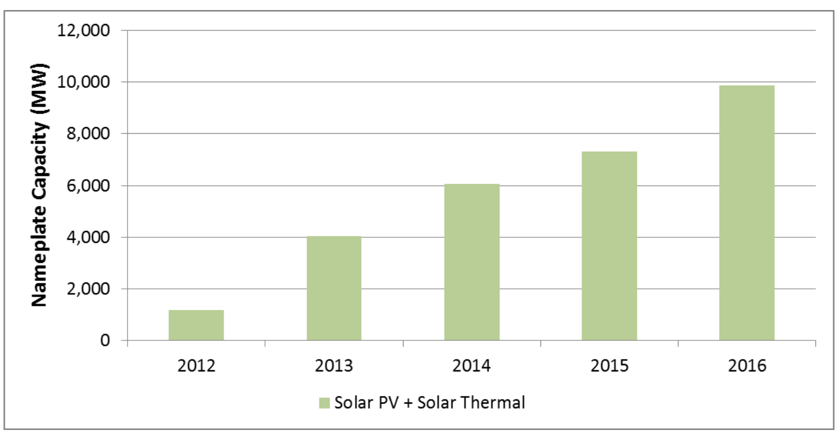

Figure 13: Installed Solar Generation in California from 2012 to 2016

Source: (California's Installed Electrical Power Capacity and Generation, 2017)

Both AESO and CAISO are responsible for managing the grid and markets to ensure access to reliable power. Operational constraints of the economy prevent customers from curtailing their consumption for extended periods of time. Small retail consumers have few options for limiting their exposure to variable prices in deregulated markets. Unless they have access to storage, such as batteries, they cannot buy during periods of low price and use during periods of high price. The structure and composition of energy markets in Alberta and California create an opportunity for BC Hydro to develop useful flexible resources such as PHS.

2.3 Valuation Methods

The objective of an economic analysis is to provide the information needed to make a judgement or decision. Since each power system will benefit differently from the introduction of PHS there is not a single set method for determining the PHS system's value. Some of the many methods are discussed in this section to provide direction towards the methodology proposed in this thesis. There are two approaches outlined in (Koritarov, Guo, Erik, Trouille, Feltes, & Reed, 2014) to value PHS projects: cost-based and market-based. Cost-based approaches are typically used when the PHS project is operating in a traditionally regulated utility. This is a system-level approach where the value is measured by the benefits that the PHS project provides to the power system in which it operates. In contrast, the market-based approaches are typically used in restructured electricity markets. This approach focuses on the revenue streams that the PHS project can participate in within a competitive market environment.

2.3.1 Cost Based

One such method is a levelized cost of storage analysis to compare various use cases and technology options including projected capital cost delineations (Lazard, 2016). It was therein proposed that the value gained from storage is highly dependent on context, i.e. the market where it is participating, so the analysis addresses the cost only. One size of PHS was considered; a 100 MW plant with 800 MWh of storage operating for 20 years. The Levelized Cost of Storage was found to vary between $US 152/MWh and $US 198/MWh.

A methodology of determining value on a case by case basis has also been proposed in (Akhil, et al., 2013). Various technology types were compared on a cost basis based on levelized cost of energy or lifecycle cost estimates prepared through consultation with industry contacts. Value was determined based on storage requirements and locational needs of grid operators and planners. The cost per MW for historical and proposed PHS projects was found to decrease as a function of the capacity. This trend is most significant in projects with capacities below 500 MW. In this range, the estimated capital cost is $US 1,200/kW to $US 1,400/kW in 2010 dollars. A procedure for the economic analysis of PHS that compares conditions with and without PHS is discussed in (American Society of Civil Engineers, 1989). Here the total benefits of the PHS system are said to be the sum of savings in the capital cost stream, operating cost stream and the dynamic benefits. It also discusses the use of system planning models for determining these benefits.

2.3.2 Market Based Methods

Another method of valuing PHS was in the context of wind integration in BC (Rivas Guzman, 2010). The wind integration costs were compared with and without the addition of PHS using two optimization models. Various PHS nameplate capacities of pump-turbines at the Mica Dam, coinciding with levels of wind penetration, were tested and their benefits compared. Capital costs were estimated using an average of existing available data on similarly sized pumped storage projects. The capital costs were split into two categories based on if it was a newly developed (greenfield) site or an addition to an existing hydroelectric plant. The average cost of a PHS plant was found to be $US 990/kW and the average cost of the expansion of an existing conventional hydro project to be $US 920/kW.

Potential untapped sources of benefits from energy storage systems have also been examined (Berrada, Loudiyi, & Zorkani, 2016). Energy storage systems can participate in energy markets servicing ancillary services, arbitrage, and congestion relief. Participation for spinning and non-spinning, and regulation services is still limited in several markets. This study asserts that limiting benefits only to arbitrage will lead to undervaluing energy storage. The additional benefits that are suggested to be explored are shown in Figure 14. As shown in Figure 14, the value for regulation control is much higher compared to the value from arbitrage.

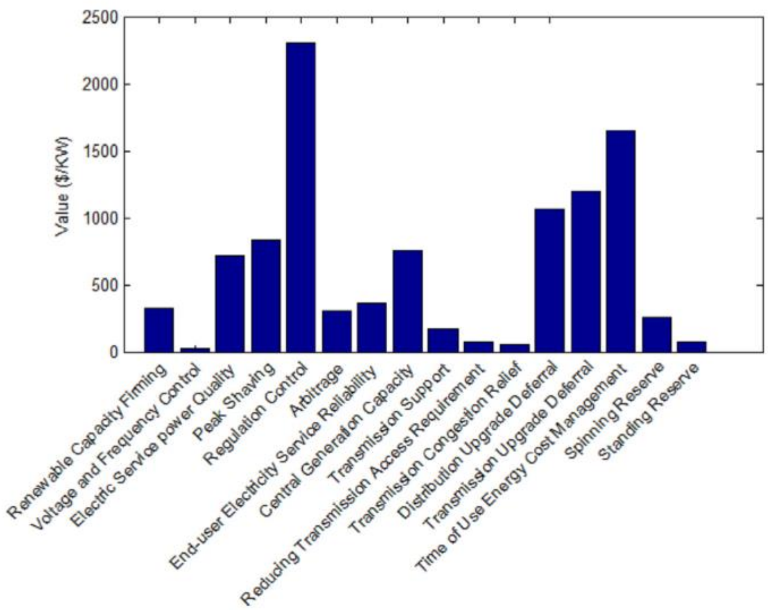

Figure 14: Estimation of Benefits of Energy Storage Applications

Source (Berrada, Loudiyi, & Zorkani, 2016)

2.3.3 Cash Flow Analysis

In order to compare the investment value of projects with different characteristics, cash flows are often estimated and discounted with respect to time. These cash flows are discounted in order to account for the time value of money. This section will provide background in order to understand the mechanics of a cash flow analysis; however it is not completely comprehensive. Extensive background exists in the literature and the reader is directed to any textbook related to Engineering Economics such as (Newnan, Whittaker, Eschenbach, & Lavelle, 2014). Cash flows are inflows or outflows of money contributing to the development of a project such as revenues or construction costs. These have dimensions of quantity of money and location in time and can be calculated using Equation 3. These discounted cash flows for different projects are normally compared on the basis of their Net Present Value (NPV), Internal Rate of Return (IRR) or Benefit-Cost Ratio (BCR).

$$PV = \frac{FV}{(1+i)^n}$$

Equation 3: Present Value

Where,

PV = Present value of cash flow ($)

FV = Future value of cash flow ($)

i = Interest rate (%/100)

n = Year of occurrence of cash flow

The time value of money is accounted for using the NPV method. The NPV is the net sum of the inflows minus the outflows discounted by an interest rate adjusted based on the time at which each flow occurs. When the NPV is positive it indicates that the investment is expected to provide a return on capital. When the NPV is negative it indicates that the returns do not exceed the costs, although there may be unquantified benefits. The most common practice for NPV analyses of renewable energy projects is to group cash flows as a lump sum at the end of period cash flows, where the period is often one year (Short, Packey, & Holt, 1995).

In (Akhil, et al., 2013), the costs of different types of energy storage projects were compared on the basis of five summary cost metrics that are based on the present value of costs over the lifetime of projects. These metrics consisted of:

1. Installed Cost ($/MW): Total cost divided by the capacity,
2. Levelized Cost of Capacity ($/kW-yr): Revenue from discharge capacity per year required to cover all life cycle costs and provide the targeted rate of return,
3. Levelized Cost of Energy ($/MWh): Revenue for delivered energy required to cover cost and provide the targeted rate of return,
4. Present Value of Life-cycle Costs ($/kW Installed): Present value of annual costs divided by discharge capacity,
5. Present Value of Life-cycle Costs ($/kWh Installed): Present value of annual costs divided by usable energy storage

Metrics 2 and 3 can be used to compare against yearly revenues or benefits. Metrics 4 and 5 can be compared with estimates of present value of benefits to estimate cost effectiveness. This report generally assumes a certain amount of cycles and prices to determine revenues and charging costs. This methodology could be extended by using a dispatch model in an actual electrical system to assess the benefits.

2.4 Optimization Methods

An optimization problem is formulated to find the values of variables contained within a problem that minimize or maximize the value of an objective function. These problems are very important in the field of operations research as gains from using resources more efficiently can be very significant. In general, optimization problems contain an objective function, variables, constraints, and parameters. The objective function is what is desired to be minimized or maximized, for example maximizing profits or minimizing cost for a company. Variables are independent or dependent choices that can be made regarding the problem, i.e. how many units to produce. Variables that are included in the objective function are known as independent choices or decision variables. Constraints are limitations on the resources bounding the possibility of choices, i.e. we can only produce a maximum of ten units. Parameters are coefficients and constants that are predetermined at the onset of the problem, i.e. price of energy sold into the market.

Optimization problems are often approached using mathematical programming techniques. These problems are generally approached in the following sequence (Fourer, Gay, & Kernighan, 2002):

- Formulate a model by identifying the variables, objectives and constraints that represent the problem at hand
- Collect data defining a problem instance
- Generate a specific objective function and constraint equations from the model and data
- Solve the problem using a solver that applies an optimization algorithm to find the optimal values of the variables

- Analyze the results

Modelling languages allow for easy translation from the way humans understand a problem to the way solver algorithms are able to solve them. This allows humans to focus on the task of debugging and ensuring the model is an accurate representation of the problem. A Mathematical Programming Language (AMPL) is an algebraic modelling language used for mathematical programming. There is an interactive command environment for AMPL that is used for setting up and solving mathematical programming problems. This environment is well suited for displaying data and results, as well as for switching between different solver algorithms and selecting options that are best suited to solve the optimization problem at hand.

There are many types of optimization methods including Linear Programming, Network Programming, Dynamic Programming, Stochastic Programming, and Integer and Mixed Integer Programming. This is a very broad field and more information on the use of different optimization methods in the context of hydropower can be found in (Labadie, 2004).

2.4.1 Linear Programming

Linear programming (LP) is a very powerful method of solving certain optimization problems. It is so powerful because the method exploits computers ability to quickly perform simple calculations such as addition and subtraction. The problem is translated into a system of linear equations which can be solved extremely quickly by computers. As stated in (Berrada, Loudiyi, & Zorkani, 2016), linear programming is a benchmark model used to model energy storage dispatch. The optimization problems that can be solved using LP consist of constrained problems where the objective function and all constraints are linear. Constrained problems are those where constraints bound the value of decision variables to prevent their value from going to infinity. Other requirements for LP include a requirement for continuous and non-negative variables. The continuous requirement results in that there is no guarantee that decision variables in the optimal solution will be an integer. Problems where physical constraints require discrete values for variables, such as a discrete value of the variables, can either be solved using other methods such as the branch and bound method or the values can be rounded and rechecked to make sure constraints are satisfied.

A typical LP problem is shown in Table 3 below.

Table 3: Simple Linear Programming Problem

Objective Function: $$Maximize: z = c_1x_1 + c_2x_2$$
Constraints: $$a_{11}x_1 + a_{12}x_2 \leq b_1$$ $$a_{21}x_1 + a_{22}x_2 \leq b_2$$ $$x_1 \geq 0$$ $$x_2 \geq 0$$
Where, z = Value to be maximized x_1, x_2= Decision variables c_1, c_2= Coefficients for decision variables a_{11}, a_{12} = Parameters for constraint 1

a_{21}, a_{22} = Parameters for constraint 2

b_1, b_1 = Parameter bounding constraints

Source: (de Neufville, 1990)

There are situations in optimization where the value of a coefficient can change based on the value of the variable. An example of this is in economies of scale where the unit cost of a product decreases as more products are produced. In hydropower engineering the relationship between power produced and water released through the turbine is not constant. This relationship is known as the production function (Shawwash, A Decision Support System For Real-Time Hydropower Scheduling in a Competitive Power Market Environment, 2000). There is a peak efficiency of a turbine which is a component of the design of a hydropower plant. A piecewise linear curve can be used to represent this relationship as shown in Figure 15 below. In this hypothetical figure, the efficiency represented by the slope of the discharge vs. generation curve is decreasing as the discharge through the turbine increases.

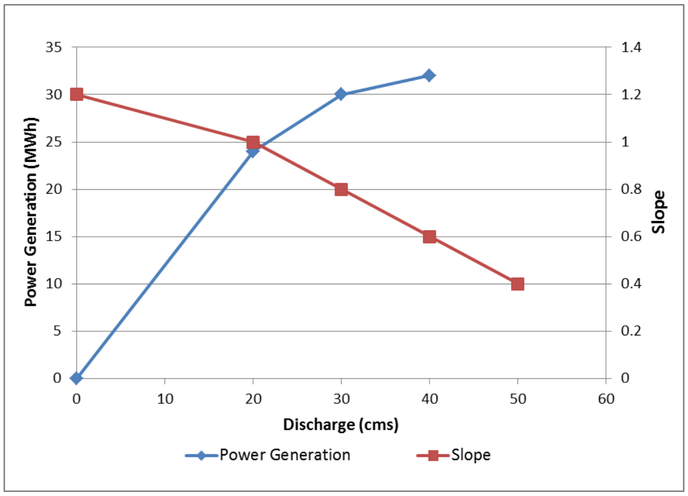

Figure 15: Piecewise-linear Approximation of Flow vs. Discharge

In AMPL, piecewise linear functions are represented by a set of breakpoints and slopes, i.e. *<<breakpoint list; slope list>> variable*. The number of slopes must be one more than the number of breakpoints, which must be ordered and non-decreasing. In the example shown in Figure 15, where the piecewise linear function to calculate the power generated would be represented by *<<0, 20, 30, 40; 1.2, 1, 0.8, 0.6, 0.4>> Q*, where Q represents the discharge.

The optimization of the dispatch of hydroelectric plants over a period of time belongs to a larger set known as unit commitment problems. The results of this optimization are very important for planning releases from the reservoir over the course of time. In this case, the objective for a vertically integrated utility could be matching the energy demand at minimum cost or in a restructured market to maximize revenues from energy production. The variables for this problem include discharge from turbines, volume of water in the reservoirs or power produced at each facility. Parameters would include piecewise linear functions representing the power production functions, market prices for electricity and natural inflows into reservoirs. Constraints would include limits on the quantity of discharge from turbines, levels of the reservoirs and electricity sold in the market. This is a simplified hypothetical version of the problem, which has been explored in great detail as will be described in the following section.

2.4.2 Applications to Pumped Storage

The purpose of using optimization models in the context of multireservoir systems is to improve the operational efficiency and effectiveness of a system by using computer modelling tools to create reservoir operation plans that use rational decision making. A good summary of the use of optimization methods for the operation of multireservoir systems in general can be found in

(Labadie, 2004). There are many papers that discuss the application of optimization models for the dispatch of PHS. This section discusses models that have been developed specifically for optimizing PHS systems.

In (Koritarov, Guo, Erik, Trouille, Feltes, & Reed, 2014) simulation models were developed for advanced PHS technologies in order to determine their technical capabilities as well as their value. The advanced PHS technologies that were modelled were for adjustable-speed and ternary units. This analysis was performed on varying sizes and compositions of systems which included the Western Interconnection, California electricity market, and the Sacramento Municipal Utility District.

(Berrada, Loudiyi, & Zorkani, 2016) used a linear programming model to estimate the daily profit of a gravity storage system using data from the New York Independent System Operator (NYISO). It compared the profitability of this system to other energy storage systems including PHS and CAES. The system could participate in both the day ahead and real time market for energy and ancillary (regulation) services. Each hour of the day the model determines how much energy to charge or discharge from the storage system based on market conditions. The amount of energy remaining in the system is a sum of energy remaining from the previous timestep and the energy used for charging (negative) or discharging. Binary variables were used because a separate variable was used for charging and discharging decision and the authors wanted to prevent the system from simultaneously charging and discharging in the same hour. It was acknowledged that there are other benefits created by energy storage that were not quantified in this model, including system upgrade cost deferral.

(Abgottspon & Andersson, 2014) presents a method of determining a seasonal operation strategy for a PHS system. This method decomposes the large problem into inter- and intrastage problems for the purposes of seasonal management and hourly balances respectively. The interstage problem determines weekly water values over a year and makes release decisions without information about water inflows and day-ahead market prices. The intrastage problem determines an optimal hourly schedule including spinning reserves, day ahead bidding, and production operations. Both water inflows and market prices are considered to be stochastic variables. The model was evaluated using a typical Swiss hydro plant and was optimized using the CPLEX solvers. The stochastic intrastage problem was compared to three other existing methods which include neglecting hourly flexibility, using price duration curves, and finally deterministic intrastage problems.

In (Fertig, Heggedal, Doorman, & Apt, 2013) the optimal investment timing and capacity choice for a pumped storage system was determined by optimizing the production schedule for the arbitrage market, calculating the annual revenue stream and applying a real options analysis. The pumped storage system was modelled based on a proposed upgrade to the Tonstad hydropower plant in southern Norway. The production schedule was optimized by maximizing profits in the German electricity market over successive week-long intervals. In this paper the valuation framework consists of a price model, a scheduling optimization model and the real options valuation method. The 2003 to 2010 German EEX historical prices were randomly sampled and adjusted in order to generate hourly spot market prices. A linear optimization model was then used to maximize profit of the operation of the pumped hydro system given these spot prices. A three-year construction lag, ten-year option lifetime, and 40-year project lifetime was used in this analysis. This methodology did not include other benefits such as revenues from ancillary markets or increased system flexibility. The methodology for determining the price model and the optimization model are useful. The real options valuation would only be useful from an investor's perspective rather than a project proponent.

In (Electric Power Research Institute, 2010) the value and cost of various types of electric energy storage systems was researched in order to inform industry executives, policy makers, and industry stakeholders. The key applications for projects with similar sizes in terms of capacity and energy storage to PHS were at the bulk power management level including energy arbitrage, system capacity and ancillary services. It is emphasized that the economics of energy storage are highly dependent on the capacity (MW) and storage capability (MWh). The operation of different types of energy storage and their different applications were simulated for one year using an hourly discretization. This model accounted for the charge and discharge capacity as well as storage capacity and maximized the revenue using perfect foresight for prices.

In (Argonne National Library, 2014) the following four commercial models were used in order to simulate the operation of PHS: the Power System Simulator for Engineering (PSS®E), Flexible Energy Scheduling Tool for Integration of Variable Generation (FESTIV), Conventional Hydropower Energy and Environmental Systems (CHEERS) and PLEXOS. These models were then used to determine the value of PHS in specific systems by comparing the production cost with the revenue. Scenarios were run with and without PHS plants in the system for different planning horizons including a yearly run to determine the production cost savings as well as other benefits. Models have been created specifically for the BC Hydro system including the Short Term Optimization Model (STOM) and the Generalized Optimization Model (GOM), as discussed by (Shawwash, A Decision Support System For Real-Time Hydropower Scheduling in a Competitive Power Market Environment, 2000) and (Fane, 2003) respectively. Since the value of PHS is highly system specific, it would be valuable to extend an existing model to include PHS.

2.5 Summary

This review of the literature has demonstrated that PHS is a useful and widely deployed energy storage technology that is not currently developed in BC. BC's geography is well suited for the development of PHS and interconnections with other trade partners create market opportunities. A potential barrier for its development is a lack of investment incentive caused by a lack of understanding of the value these systems can create. The value and costs of PHS projects are highly system and site specific. There are limitations for estimating the costs of PHS projects; however there are estimates for projects in BC. The literature suggests that the benefits of PHS can be estimated by using optimization models representing electrical systems. It also suggests that neglecting participation in ancillary markets and using only arbitrage markets undervalues PHS projects. More than one configuration of project should be examined as there are a wide range of projects that have been developed across the globe. Since PHS projects have a long lifetime, NPV analysis can be used to account for the time value of future benefits.

Chapter 3: Methodology

This chapter describes the methodology used for the modelling and valuation of PHS systems in the BC Hydro system. It first consists of an overview of the BC Hydro system to provide context. Next, the framework and key components of GOM are discussed. The modifications of GOM to model PHS are explained and justified. The method by which projects are evaluated and compared is discussed. Key economic parameters are described and a sensitivity analysis is proposed.

3.1 Optimization Method

For the purposes of this research, it was decided that PHS plants should be modelled as closely as possible to the method used for modelling conventional hydropower plants. Models are a representation of our best understanding of reality and are rarely perfect. It was thus decided that it would be better to add onto the existing BC Hydro GOM model rather than building a new model of the system. This section describes the BC Hydro system, describes how GOM works, and finally explains how it was extended for this research.

3.1.1 BC Hydro System

BC Hydro and Power Authority is a crown corporation that serves as the major electric utility for the province of British Columbia in Canada. It is a vertically integrated utility that controls all levels of the supply chain: generation, transmission and distribution. Approximately 95% of the population of BC or 1.9 million customers obtain their electricity from BC Hydro. Electricity is generated by BC Hydro's generation assets, purchased from Independent Power Producers

(IPPs), or purchased at market prices through transmission interties with Alberta and the United States. Electricity can also be exported through the interties when there are favorable market conditions. The interties have existed for over thirty years and consist of two 138 kV lines and one 500 kV line connecting with Alberta, and two 500 kV lines and two 230 kV lines connecting with the United States.

Energy is valued using the marginal value of water stored in BC Hydro's reservoirs and compared to market prices to make buy and sell decisions. Importing and exporting of electricity is done through Powerex, a wholly owned subsidiary of BC Hydro. BC Hydro's generating assets consist of 31 hydroelectric facilities and two thermal generating plants with a combined generation capacity of approximately 12,000 MW. A map of BC Hydro's generation assets as well as transmission lines is shown in Figure 16.

Figure 16 Map of BC Hydro's Generation Assets

Source (BC Hydro, 2013)

BC Hydro outlined their latest long-term plan in 2013 to meet BC's energy needs over a timespan of twenty years (BC Hydro, 2013). Emphasis is placed on achieving a load-resource balance where the exports and load are balanced with generation and imports. Consideration of additional supply-side energy generation resources was mainly given to a number of options including biomass, run-of-river hydroelectricity, wind, large hydro, geothermal, natural gas, wave and tidal. Although not directly within the scope of the 2013 IRP, BC Hydro recognized that energy storage is a key component of future grid asset management and operations, and planned to monitor the development of various technologies. In this report, PHS was considered as an additional capacity resource option as discussed in Chapter 2.

3.1.2 Generalized Optimization Model

Extensive planning takes place to economically dispatch resources at BC Hydro. This planning includes use of several optimization and simulation models that cover various time scales from short to long term (Rivas Guzman, 2010). The model used in this research builds on the Generalized Optimization Model (GOM) which was developed in-house at BC Hydro. GOM is a linear, deterministic optimization model that has a goal of optimizing the value of resources while meeting domestic demand (Rivas Guzman, 2010). Since GOM is a proprietary tool used by BC Hydro, the equations expressed in this section will be simplified to convey main purpose. It includes operating constraints, intertie limits, historical inflows, and reservoir storage targets to determine the optimal dispatch strategy to maximize the value of generating resources (BC Hydro, 2015).

A simplified version of the objective function in GOM is shown in Equation 4 below. Studies are normally run for a one year period with an hourly discretization, where decisions take place each hour. GOM is run over a representative set of years that include dry and wet conditions. In this formulation quantities of exported energy are treated as positive values and quantities of imported energy are treated as negative values. Prices are specified and specific to the study being undertaken and in deregulated markets can be positive or negative as discussed in Chapter 2. Although similar in shape, spot market prices for importing and exporting electricity are different reflecting wheeling charges. As discussed in the previous section, BC Hydro trades electricity with both the United States (US) and Alberta (AB). One of the major limitations of this approach is that it assumes a perfect forecast of price and all other conditions in the BC

Hydro system. This may result in an overestimate of the actual trade benefits that can be obtained in any given year.

$Maximize$:

Equation 4: Objective Function of GOM

$$\sum_{t=0}^{T}(p_{EX}^{US} * E_{EX}^{US} + p_{IM}^{US} * E_{IM}^{US} + p_{EX}^{AB} * E_{EX}^{AB} + p_{IM}^{AB} * E_{IM}^{AB})_t$$

Where,

t = Time step of study (hours)

T = Total time of study (hours)

p_{EX}^{US} = Export spot price US Market ($/MWh)

E_{EX}^{US} = Export spot quantity US Market (MWh)

p_{IM}^{US} = Import spot price US Market ($/MWh)

E_{IM}^{US} = Import spot quantity US Market (MWh)

p_{EX}^{AB} = Export spot price AB Market ($/MWh)

E_{EX}^{AB} = Export spot quantity AB Market (MWh)

p_{IM}^{AB} = Import spot price AB Market ($/MWh)

E_{IM}^{AB} = Import spot quantity AB Market (MWh)

The quantities of imported and exported electricity have multiple constraints, the most important of which are discussed next. The load resource balance is shown in Equation 5 where the sum of power generated by all generation resources and the net market trading has to be greater than or equal to the domestic load at any given time step. The original version of GOM required that the power generated by a plant had to be positive in every time step. The domestic load is an input parameter to the study. Equation 5 ensures that the domestic load is always satisfied and allows for trading to take place.

$Subject\ To$:

Equation 5: Load Resource Balance

$$\sum_{i \in Plants} P_{i,t} - E_{EX\,t}^{US} - E_{IM\,t}^{US} - E_{EX\,t}^{AB} - E_{IM\,t}^{AB} \geq L_t$$

Where,

Plants = Optimized BC Hydro Plants

t = Time step (hours)

$P_{i,t}$ = Power Generated (+) or Consumed (-) over one hour (MWh) by plant i

$E_{EX\,t}^{US}$= Export spot quantity US Market (MW) over time step (t)

$E_{IM\,t}^{US}$ = Import spot quantity US Market (MW) over time step (t)

$E_{EX\,t}^{AB}$ = Export spot quantity AB Market (MW) over time step (t)

$E_{IM\,t}^{AB}$ = Import spot quantity AB Market (MW) over time step (t)

L_t = Domestic load over hour t (MWh)

A piecewise linear curve, the HPG curve, is used to relate the amount of power generated by a plant to the required quantity of water to be released based on the forebay of the reservoir. The breakpoints of this curve are associated with operating points of high efficiency based on the optimal unit commitment and loading of the plant. The quantification of this relationship is shown in Equation 6 and will be discussed in more detail in later sections.

$Subject\ To$:

Equation 6: HPG Relationship

$$P_{i,t} \leq f(Q_{i,t}, FB_{i,t}), \forall t, \forall i$$

Where,

$f(Q_{i,t}, FB_{i,t})$ = HPG curve of plant i according to the plant forebay at the current time step

$Q_{i,t}$ = Water flow from plant i at time t (m^3/s)

$P_{i,t}$ = Power Generated (+) or Consumed (-) over one hour (MWh) by plant i

The water balance in the reservoirs is accounted for using the constraint given in Equation 7. The volume of water contained in a reservoir in each time step is equal to the sum of the volume of water contained in the previous time step, natural inflows, turbine and spill releases from upstream plants and outflows from that plant. A matrix of coefficients containing values of 0 or 1 is used to denote hydraulic connections or to specify if one plant is upstream from another. To illustrate consider the connection between the Mica and Revelstoke plants. In this example there will be eight coefficients specified in the input data as shown in Table 4.

$Subject\ To$: **Equation 7: Mass Balance**

$\forall t, \forall i$

$$V_{i,t-1} + I_{i,t} + \sum_{j\ in\ Plants} U_{i,j} * Q_{j,t} - D_{i,j} * Q_{j,t} = V_{i,t}$$

Where,

$V_{i,t}$ = Volume of water in plant i at time t (m^3)

$I_{i,t}$ = Inflows into plant i at time t (m^3)

$U_{i,j}$ = Coefficient of value 1 if plant j is upstream of plant i and is hydraulically connected, accounting for incoming water to plant i {0,1}

$D_{i,j}$ = Coefficient of value 1 if that plant j is the same as plant i, accounting for outgoing water to plant i {0,1}

$Q_{j,t}$ = Water flow from plant j at time t (m^3)

Table 4: Example of Mass Balance Coefficients for Mica and Revelstoke

i	j	$U_{i,j}$	$D_{i,j}$
Mica	Revelstoke	0	0
Mica	Mica	0	1
Revelstoke	Revelstoke	0	1
Revelstoke	Mica	1	0

Water flow from a plant has additional considerations including Columbia River Treaty obligations and environmental constraints. Two major examples of these additional considerations are fish flows and flows to satisfy the conditions of Columbia River Treaty with the US. A simplified version of these considerations is shown in Equation 8 and Equation 9 below. As shown in these equations, the maximum flow is a function of the forebay.

$Subject\ To$:

Equation 8: Turbine Bounds

$$Q_{i,t}^{min} \leq Q_{i,t} \leq \ Q_{i,t}^{max}, \forall t, \forall i$$

Where,

$Q_{i,t}^{min}$ = Minimum turbine flows through plant i at time t (m^3/s)

$Q_{i,t}^{max}$ = Minimum turbine flows through plant i at time t (m^3/s)

$Q_{i,t}$ = Turbine flows through plant i at time t (m^3/s)

$Parameters$ **Equation 9: Parameters for Turbine Bounds**

$$Q_{i,t}^{max} = f(FB_{i,t}), \forall t, \forall i$$

Where,

$FB_{i,t}$ = Forebay of reservoir of plant i at time t (m)

An important characteristic of a plant is the shape of the reservoir. This is important because there are many parameters in the model that use the forebay of the reservoir as an input, yet the mass balance equation shown above is in volumetric units. This relationship between forebay and storage is unique to each reservoir and is known as the storage elevation curve. This curve, represented by Equation 10, is piecewise linear with a number of breakpoints and slopes that characterize the three-dimensional shape of the reservoir.

$Parameters$ **Equation 10: Storage Elevation**

$$FB_{i,t} = f(V_{i,t}), \forall t, \forall i$$

Where,

$V_{i,t}$ = Volume of water in reservoir i at time t (m^3/s * day)

3.1.3 Modifications to GOM

The BC Hydro system is primarily composed of conventional hydroelectric projects. Within GOM these projects are fundamentally composed of a power house (plant) with an upper reservoir. Since

PHS plants have an upper and lower reservoir this paradigm had to be slightly altered. Essentially, instead of one plant there needs to be two as shown in Figure 17. The lower plant has no generation capacity and is just acting as a reservoir. Positive turbine flows (i.e., in generation mode) from the upper plant takes water from the upper reservoir and empties it into the lower reservoir. Negative turbine flows (i.e., in pumping mode) from the upper plant takes water from the lower reservoir and empties it into the upper reservoir.

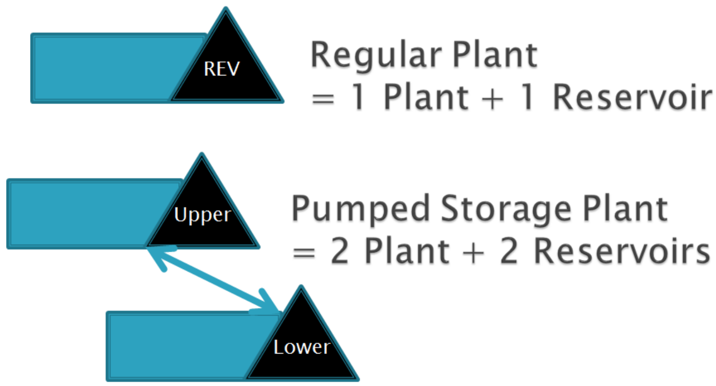

Figure 17: GOM Paradigm of Conventional Hydroelectric Projects and PHS Projects

The PHS models that had been made in the past were "one offs" and were not generalized to be able to model any configuration of PHS. One of the goals of this research is to model any situation and so a generalized model was formulated. In order to have a fully generalized model of PHS it is prudent to be able to model all realistic configurations. These configurations or scenarios are combinations of new and existing BC Hydro plants as the upper and lower reservoirs. The four scenarios are as follows:

1. The upper reservoir is an existing reservoir and the lower reservoir is an existing reservoir.
2. The upper reservoir is an existing reservoir and the lower reservoir is a new reservoir.
3. The upper reservoir is a new reservoir and the lower reservoir is an existing reservoir.

4. The upper reservoir is a new reservoir and the lower reservoir is a new reservoir.

This research focuses on Scenario 1, an extension of an existing plant, and Scenario 4, a representation of a closed-loop project. These two scenarios were chosen because extensions of existing projects require less work to be constructed and closed-loop projects are hydraulically independent of other river systems. In addition these were the two configurations of projects included in the 2013 IRP, meaning there is readily available economic and technical data.

The changes designed to represent a PHS system used the same formulation setup as conventional hydropower plants. This was important for modeling the BC Hydro system as any significant changes to the GOM input database are costly impractical in the timeline of this research. This model was developed with the intention of avoiding binary variables and non-linear problems to avoid long computation and solve times of the optimization problem. Binary variables are regularly used when modelling pumped storage systems when both a variable for pumping and for generating flows are created. In such formulations, a binary variable is added to prevent the system from simultaneously pumping and generating.

In developing the model in this thesis one variable was used to represent water flows and one for power, in both cases positive values indicating generation and negative values indicating pumping. In GOM these variables correspond to the turbine flows (QT) and power (P). These two variables are linked with each other through non-linear relationships of flow and power generation which is dependent on the head difference between the upper and lower reservoir. These relationships are known as the HPG curves, and are different for each PHS system. In this research, this curve was extended to include negative values of QT and P representing a variable speed pump turbine. The key for adding a PHS system within GOM is the hydraulic matrix that connects flows between plants. As discussed in the previous section these connections are used as coefficients to flows in the mass balance equations and are represented as either 1 indicating a connection or 0 indicating no connection. The modifications included values of -1 to consider flows in the opposite direction. The following section will describe the hydraulic matrix and explain the implications for the mass balance for Scenario 1 and Scenario 4.

Scenario 1

To reiterate, Scenario 1 is a modification of an existing hydroelectric facility. It utilizes two existing plants and their reservoirs, adding the flexibility to pump water from the lower reservoir to the upper reservoir. An example of this is an extension of the Mica plant (Mica Extension), ultimately involving the upstream Mica plant and downstream Revelstoke plant. In this case a new plant, "PSP1", is added to the model acting as a parallel plant to the existing Mica plant. This is shown in Figure 18 where MCA represents the Mica plant with an associated upstream reservoir and REV as the Revelstoke plant with an associated upstream reservoir.

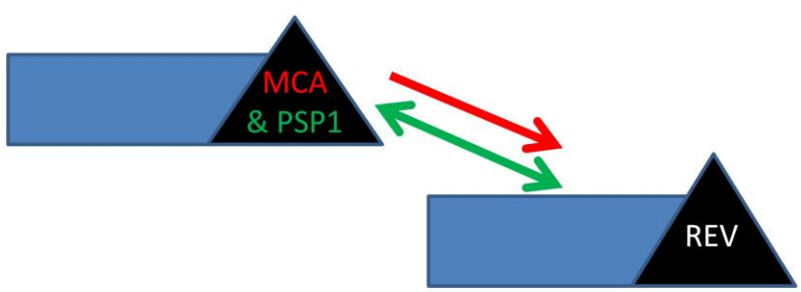

Figure 18: Configuration of Scenario 1 for Mica Extension

In this figure red and green arrows indicate the direction of flow between reservoirs through plants.

The PSP1 plant is connected to the Mica and Revelstoke reservoirs. When PSP1's turbine flows are positive it is generating and water is drawn from MCA's reservoir and added to REV's reservoir. When PSP1's turbine flows are negative it is pumping and water is drawn from REV's reservoir and added to MCA's reservoir. No water enters or exits PSP1's reservoir at any time. The matrix configuration is shown in Table 5 below with the mass balance shown in Table 6.

Table 5: Example of Matrix Coefficients for Scenario 1

i	j	$U_{i,j}$	$D_{i,j}$
Mica	Revelstoke	0	0
Mica	Mica	0	1
Mica	PSP1	0	0
Revelstoke	Revelstoke	0	1
Revelstoke	Mica	1	0
Revelstoke	PSP1	0	0
PSP1	Revelstoke	1	0
PSP1	Mica	-1	0
PSP1	PSP1	0	0

Table 6: Mass Balance for Scenario 1

i = Mica

$$V_{MCA,t-1} + I_{MCA,t} + (-1)Q_{PSP1,t} - (1)Q_{MCA,t} = V_{MCA,t}$$

i = Revelstoke $$V_{REV,t-1} + I_{REV,t} + (1)Q_{PSP1,t} + (1)Q_{MCA,t} - (1)Q_{REV,t} = V_{REV,t}$$
i = PSP1 $$V_{PSP1,t-1} = V_{PSP1,t}$$ $$V_{PSP1,t} = V_{MCA,t}$$

In this scenario, the volume of water in PSP1's reservoir does not change as there are no inflows or outflows. The limitation of this is that the bounds of the PSP1's turbines flows should be a function of Mica's forebay. In order to address this issue, the upper reservoir for a PHS is specified as an input parameter and in this case PSP1's forebay is updated during each iteration to match that of Mica.

<u>Scenario 4</u>

A closed-loop PHS using two new plants and reservoirs is represented in Scenario 4 as shown in Figure 19. In this case the PHS is not hydraulically connected to any of the existing BC Hydro system. PSP1 is a normal pumped storage plant with storage, and capacity to generate and pumping. PSP2 is a plant with a reservoir and no generating or pumping capacity. In this case the upper reservoir of the PHS is PSP1.

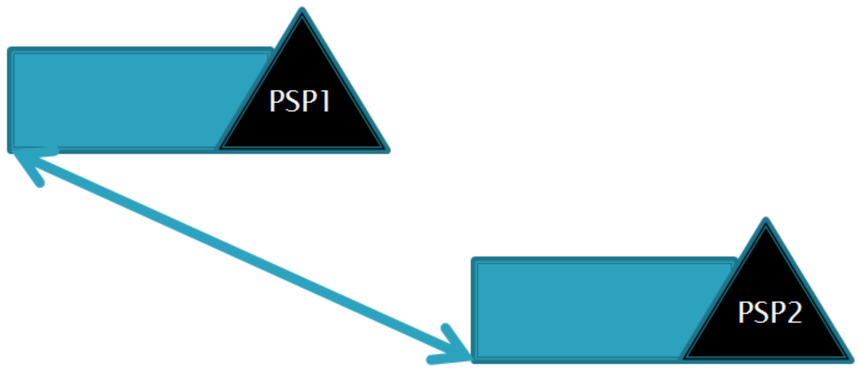

Figure 19: Configuration of Scenario 4 for a Closed Loop Project

In this figure the blue arrows show the potential direction of flow between PSP1's and PSP2's reservoir. This flow is controlled by PSP1's plant or turbine flows. When PSP1's turbine flows are positive it is generating and water is drawn from PSP1's reservoir and added to PSP2's reservoir. When PSP1's turbine flows are negative it is pumping and water is drawn from PSP2's reservoir and added to PSP1's reservoir. The matrix configuration is shown in Table 7 below with the mass balance shown in Table 8.

Table 7: Example of Matrix Coefficients for Scenario 4

i	j	$U_{i,j}$	$D_{i,j}$
PSP1	PSP1	0	1
PSP1	PSP2	1	0
PSP2	PSP1	0	0
PSP2	PSP2	0	0

Table 8: Mass Balance for Scenario 4

i = PSP1 $$V_{PSP1,t-1} + I_{PSP1,t} - (1)Q_{PSP1,t} = V_{PSP1,t}$$	
i = PSP2 $$V_{PSP2,t-1} + I_{PSP2,t} + (1)Q_{PSP1,t} = V_{PSP2,t}$$	

Another important part of modelling PHS in GOM was adding dynamic limits to the pumping flows. The limits on these flows should be a function of the difference between the upper and lower reservoirs or forebay of the upper reservoir, similarly to how the maximum turbine flows are limited in Equation 9. Since one variable was used to represent both pumping and turbine flows, the minimum turbine flows are the same as the maximum pumping flows. The formulation of these new bounds is shown below in Equation 11.

Equation 11: Minimum Turbine Bounds

$Parameters$

$Q_{i,t}^{min} = f(FB_{i,t}), \forall t, \forall i$

Where,

$Q_{i,t}^{min}$ = Minimum turbine flows through plant i at time t (m^3/s)

The final modification that was introduced in GOM was to include the ability to sell ancillary services. The services that were included were the regulation and spinning reserves in both the up and down directions. All hydro plants in GOM could provide spinning reserves; however only hydro plants equipped with Automatic Generation Control (AGC) could provide regulation reserves. These services were represented in the model as shown in Table 9. In addition, parameters were added to represent the market value of each of these services. Both directions of spinning reserves had the same price, and each direction of regulation reserve had a different price. These variables were added to the reserve calculations where extra capacity is held using constraints to account for contingency events. Finally these variables, along with parameters representing their cost, were added to the objective function.

Table 9: Variables Added for Ancillary Services

Variable	**Description**
Reg_Up(t)	Quantity of regulation up service sold in the market at time t
Reg_Down(t)	Quantity of regulation down service sold in the market at time t
Spin_Up(t)	Quantity of spinning-up service sold in the market at time t
Spin_Down(t)	Quantity of spinning-down service sold in the market at time t

During the course of this research there were other items that were explored for extensions of GOM. One of these items was to create a constraint for the PHS to require it to be used for a certain amount of consecutive hours. This resulted in the model becoming non-linear and extended the solution time beyond an acceptable level. Another was constraining the total number of times the model could switch between charging and discharging using a simplified storage model. This resulted in the model becoming a Mixed-Integer Problem, where the solution time and CPU usage increased beyond an acceptable level. Another approach was also investigated during the process of modifying GOM for including PHS. In this approach an additional variable was created that represents pumping flows for every plant in the system. A number of additional complications arose, including changing most existing constraints and the need for binary variables that would change the solution method of the problem, which led to the focus on the single variable approach.

3.2 Analysis

This section discusses the method by which each project is evaluated and how the projects are compared. The components of this evaluation include revenues and costs incurred throughout the expected lifetime of the project. The revenues were considered as the incremental increase in the objective function from including each PHS project. The costs of the projects included a rough estimate of the capital cost, and the operations and maintenance cost. The analysis includes impacts on the BC Hydro system as a whole, benefits of individual projects, and the value of these projects by comparing benefits and costs.

3.2.1 Revenues

The yearly benefit was estimated by calculating the difference between the objective function from the optimization of the case with PHS to the base case without PHS. All other inputs between the two cases are identical to highlight the impact of the inclusion of PHS, This incremental benefit, as shown in Equation 12 was considered as the source of revenue for the project.

$$R_y = E_y^b - E_y^S$$

Equation 12: Revenue as Incremental Benefit

Where,

R_y = Revenue or benefit in year y ($)

E_y^b = Value of objective function of base case in year y ($)

E_y^S = Value of objective function including PHS in year y ($)

For the purposes of this research an existing BC Hydro study was used which is discussed in detail within Chapter 4. It was decided to use an existing study rather than creating an entirely new one because this represents conditions that are realistic and a possible configuration of the system. This study contains a representative set of historic and future conditions that BC Hydro uses in other planning studies. Changing inputs of the study would introduce levels of uncertainty that go beyond the scope of this thesis. The benefits that are captured using this method are increasing the system efficiency and capitalizing on trade opportunities in the energy and ancillary services markets.

There are some inherent assumptions that are made when using this method to calculate the benefits. First, it assumes that transactions in the energy and ancillary markets occur without affecting the price. Realistically, because of the way the market is cleared as explained in Chapter 2, as more power is offered the price will decrease. This assumption likely leads to an overestimation of the benefits, however it is currently used in this model and is deemed acceptable. In addition there is a liquidity limit, or market depth, constraining the amount of energy that can be sold in the market. This method assumes that the liquidity limit is bounded by the transmission constraints, not by the market itself. This assumption also likely leads to an overestimation of benefits. In addition since this model is run for a year at a time and is deterministic, the PHS has perfect foresight of weather conditions and market prices. This leads to an overestimation of the benefits since it is able to capitalize on every available arbitrage opportunity and always sell the excess capacity in the ancillary markets. These assumptions are present in both the base case and the case including PHS and the intent here is to see the increased value of having PHS. Models are not always perfect representations of reality and it is important to understand the limitations that can affect the results.

3.2.2 Costs

The two components of cost considered in this study were the capital cost, and the operations and maintenance cost. As is discussed in the above section this study includes both closed loop PHS projects (Scenario 4) as well as one project that is an extension of an existing hydroelectric facility (Scenario 1). The costs for Scenario 4 and Scenario 1 projects were obtained from (Knight Piésold Consulting, 2013) and (Hatch, 2010) respectively.

The capital cost of the Scenario 4 projects was estimated using the Unit Cost of Stored Energy for the site chosen in Chapter 2. The Unit Cost of Stored Energy was multiplied by the amount of stored energy for each project and updated to reflect the effects of inflation from the date of the report. The capital cost for PHS is extremely site specific and it is challenging to find estimates or even methods of determining the scale of costs when increasing the capacity or storage at a given site. Physical, geographical and environmental factors are a major factor in determining project costs (MWH Americas, Inc, 2009). There are not enough PHS plants in North America to create a cost characterization from statistical analysis (MWH Americas, Inc, 2009). In general the Unit Capacity Cost should decrease as a function of capacity, reflecting economies of scale, as shown in (MWH Americas, Inc, 2009). However as shown in (Knight Piésold Consulting, 2013), there are instances of projects with a lower capacity costing more than those with higher capacities as shown in Figure 20.

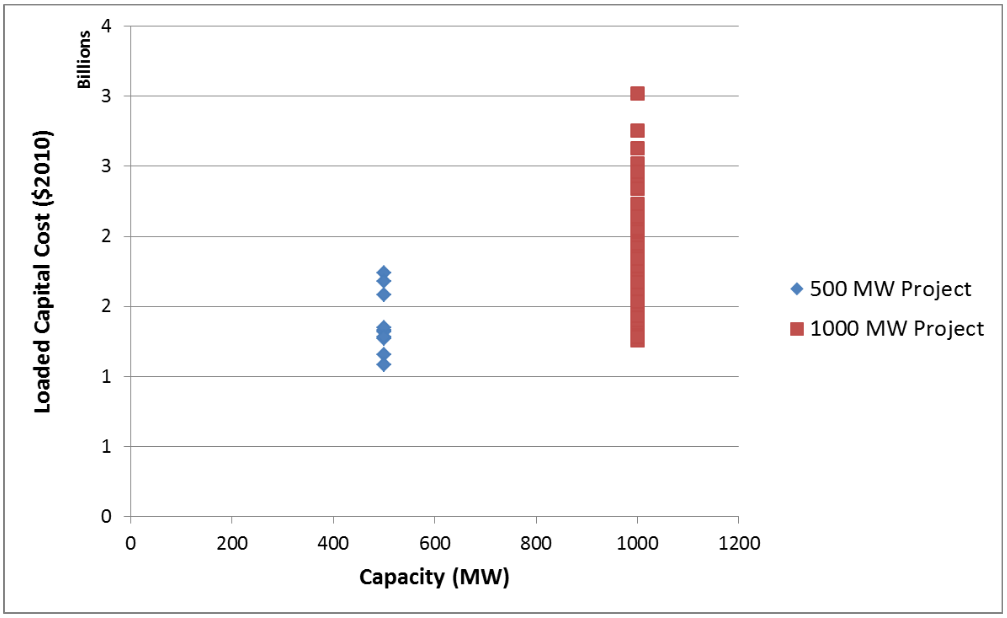

Figure 20: Loaded Capital Cost ($2010) vs. Capacity

Adapted from (Knight Piésold Consulting, 2013)

One of the goals of this thesis is to determine trade-offs between capacity and storage. Two projects could hypothetically have the same storage with different capacities based on their reservoir sizes, i.e. Project 1 has 100 MW with 2 hours of storage for 200 MWh and Project 2 has 200 MW with 1 hour of storage for 200 MWh. The tradeoffs in terms of cost are between additional generation equipment and additional construction cost. Although the Unit Capacity Cost could be used to estimate project costs, it would give little insight into tradeoffs between costs of projects with more storage with the same capacity. The estimated capital cost from (Knight Piésold Consulting, 2013) as well the average respective percentage of the total included the following for freshwater sites:

- Mobilization, demobilization, bonds, overhead and contractor’s profits (17%)
- Permitting and design (6%)
- Generation equipment and switchyard (24%)

- Construction costs (31%)

As shown above, it is challenging to determine the relative impact on cost a slightly higher capacity project would have (generation equipment and switchyard) compared to a slightly higher storage project (higher construction costs). The capital cost did not include transmission, interconnection or road access to the site.

The capital cost of the Scenario 1 project (Mica Extension project) was obtained from (Hatch, 2010) using the option from the reversible pump-turbine powerhouse with variable speed units. This capital cost in 2010 dollars is $669,000,000 which was calculated on the basis of the following items (Hatch, 2010):

- Equipment pricing from other studies and projects
- Project contingency
- Engineering and administration cost
- Excavation and construction costs
- Exclusion of BC Hydro management and overhead costs

The fixed operation and maintenance cost was set to be 1% of the total capital cost each year the project was in service. The variable operation and maintenance cost, dependent on how much power was pumped or generated, was assumed to be included in the fixed cost. An assumption made here is that the operations and maintenance costs are constant throughout the duration of the project. Realistically, the shapes of these cash flows are not constant because some years may require more work than other years. It is assumed that over the lifetime of the project these converge to the average value. The shape of the cash flows would be more important for a year to year management of accounts and the scope of this analysis is to examine the project from a high level.

3.2.3 Economic Parameters

For this study the capital costs have been updated from the year the reports were published to the present year using the average inflation rate of 2% as described in Chapter 4 of (BC Hydro, 2013). The discount rate used to account for the time value of money was 6% which is representing the average between rates used from (BC Hydro, 2013). This is also the value used as the discount rate in (Knight Piésold Consulting, 2013). The lifetime of all projects was chosen to be 70 years, as used in (Knight Piésold Consulting, 2013) and in the reasonable range of lifetimes as 50 to 100 years stated in (Deane, Gallachóir, & McKeogh, 2010). The residual value of the project was not considered in this analysis, as it was generally not included for PSH projects in the literature.

3.2.4 Value

The value of PHS was examined from the following three perspectives: the physical impacts on the system (System Study), the incremental economic benefits or effect of the inclusion on the objective function (Benefits Study), and finally levelized impacts in terms of costs and benefits (Cash Flow Study).

System Study

The purpose of this section is to examine the physical effects of including PHS. In order to examine these effects first the results of the optimization will be studied to make sure the correct behavior is observed. Simply put, when the PHS plant is generating power water should be leaving the upper reservoir and drawing its forebay down. This water should be entering the lower reservoir and bringing its forebay up. The opposite behavior should occur when the PHS is pumping. This can be studied by plotting time series of the upper and lower reservoirs forebays along with the flow from the plant.

The next step in ensuring that reasonable behavior took place is to look at the cumulative energy pumped and generated by a plant. Due to the inefficiencies in the pumping and generating mode there should be more energy used for pumping than is ultimately generated. This can be calculated by conditionally summing the hourly power based on its sign. Summing all of the positive values will show the total energy generated throughout the year and similarly summing all the negative values will show the total energy pumped throughout the year. It is possible that more energy could be generated than pumped in the Mica Extension case where there are natural inflows to Kinbasket Lake. The ratio of energy generated to energy pumped is a measure of the roundtrip efficiency of each project. It is expected that the efficiency is in the range of 70 to 85% (Barbour, Wilson, Radcliffe, Ding, & Li, 2016). This comparison was done for different representative conditions of the BC Hydro system to see the potential variation of use. It also compared the average values between the different configurations of storage and capacity.

Benefits Study

The purpose of this section is to examine the yearly benefits of including PHS. Since there is a significant amount of BC Hydro’s confidential information contained in the study the results will be normalized using the process outlined in Equation 13.

$$x_{i,norm} = \frac{x_i - \min(x)}{\max(x) - \min(x)}$$

Equation 13: Normalization Process

Where,

$x_{i,norm}$ = Normalized benefit x of i

$x = (x_1, \ldots, x_n)$

$\min(x)$ = minimum value of set x

$\max(x)$ = maximum value of set x

The absolute benefits will first be compared across the set of years to see how much they vary. It is expected that the benefits will be non-uniform across water years. It is also expected that the benefits will be highest in the more extreme years in terms of hydrologic conditions. The PHS should create the most incremental benefit when the system as a whole is most constrained, as it adds flexibility. The benefits for closed loop projects with similar capacities (Scenario 4) to the Mica Extension project (Scenario 1) are compared. For the closed loop projects, the benefits will be compared first with the capacity (MW) and then with the storage (MWh). It is expected that in general the benefits will increase with capacity and with storage, but that there are diminishing returns. The Case Study will be set up so that there will be projects with different capacities and the same storage to investigate the relative benefits. Finally, the benefits will be levelized by the capacity and then the storage. Levelizing the benefit will show if the benefits increase proportionally to these parameters.

Cash Flow Study

The purpose of this section is to look at the projects taking both the benefits and costs into account. The methodology proposed in this thesis uses the concept of discounted cash flows to reflect the time value of money discussed in Chapter 2. This concept builds on the cost metrics that were discussed in (Akhil, et al., 2013). The lifetime of the project (e.g., 70 years) was discretized by year. To give a representative distribution of benefits over the lifetime of the project, each year was assigned a random integer from a set of numbers 1 to 10 using a uniform distribution. Each of these numbers corresponds to a different year of a representative set of conditions for the BC Hydro system, as will be further explained in Chapter 4. Each of these years has a corresponding benefit representing the incremental increase in the objective function of GOM from the base case to the case where the PSH project is included as the revenue. The net cash flow for the end of the year was calculated and discounted to the present. The capital costs are incurred as overnight costs in year 0 without any revenue or operations cost. This analysis is from the perspective of BC Hydro where the project would be funded by equity; the nuances of finance are neglected because of the high level of this analysis. In addition the NPV was weighted by the configuration: by the capacity of the project (MW) and by the amount of energy that can be stored in the upper reservoir (MWh). These terms are defined here as the NPV Benefit or Cost of Capacity ($/MW Installed) and the NPV Benefit or Cost of Storage ($/MWh Installed). If the NPV is positive it is referred to as a benefit and if negative it is referred to as a cost. These terms extend the present value metrics that include future costs to also consider the future benefits.

The NPV for each project can be summarized by Equation 14, where the representative set of years shown is from 1964 to 1973.

$$NPV = \sum_{t=1}^{N}\left[\frac{R(U[1{,}10])_t - O_t}{(1+d)^t}\right] - C$$

Equation 14: NPV in Cash Flow Study

$$\mathrm{R}(\mathrm{U}[1{,}10]) = \begin{vmatrix} 1 & \mathrm{R}_{1964} \\ \dots & \dots \\ 10 & \mathrm{R}_{1973} \end{vmatrix}$$

Where,

NPV = Net present value ($)

t = year

$U[1{,}10]$ = Random number from uniform distribution [1,…,10]

R_t = Revenue of year t, as sampled from U[1,10] ($)

O_t = Operations and maintenance cost of year t ($)

C = Capital cost of project ($)

d = Discount rate (%)

3.2.5 Sensitivity

Finally a sensitivity analysis will be performed for the Cash Flow Study. The purpose of this section is to look at the sensitivity of the NPV to the input parameters. The results will be shown in a Spider Chart, which shows the NPV against different values of the input parameters. The first parameter that will be varied is the yearly benefits. The benefits for every year of the project will be varied between the minimum of the set of ten years for the worst case, and the maximum for the best case. The other parameters that will be varied will be the capital cost, operations and maintenance cost, inflation rate, and the discount rate. For each parameter a pessimistic and optimistic value was determined and the NPV recalculated.

The capital cost for all projects was varied by increasing and decreasing the base input cost by 40%. This choice was based on the range chosen by comparing and to be within the range expressed in (Hatch, 2010) report (-35% to +50%) and using the range from (Rivas Guzman, 2010) (+/- 20%). Since this cost is very uncertain the range of variation should be large but symmetrical. The cases for benefits were chosen using the minimum and maximum incremental increases in the objective function. The range of the discount rate was chosen using the rates listed for BC Hydro and IPP projects as 5 and 7% (BC Hydro, 2013). The inflation rate was varied by looking at the highest and lowest values for the yearly change in the Canadian Consumer Price Index (CPI) between 2010 and 2018. The operations and maintenance cost as a percentage of capital cost was varied between 0.5 and 1.5% as is the range for different sizes and types of PHS projects in (Knight Piésold Consulting, 2013).

The intent of this sensitivity analysis is to get an idea of the variability of the NPV caused by uncertain parameters used in this research. This sensitivity analysis does not encompass all aspects of uncertainty of each project. There are too many uncertainties, such as turbine characteristics, and long term changes in power prices and reservoir inflows, etc., to do a sensitivity analysis on each one. The idea here is to just test the critical ones that were created as a result of this research.

Chapter 4: Case Study

This chapter provides information about the case study that was used for the research. It first outlines the choice for the range of project characteristics that were studied. Next, it discusses the projects chosen for the case study and how the GOM input parameters were estimated. It then describes other input parameters used for the base case including the load, market prices, and the other plants that were optimized in the study.

4.1 Introduction

Two types of PHS plants were modelled for this study: a stand-alone plant and an extension of an existing plant. These two types were chosen because of the availability of technical and cost data and to assess the difference between these two development options described in Chapter 2. A range of configurations of stand-alone plants and one configuration of an extension plant were chosen. There was much more technical information provided in the 2013 IRP for the extension project than the stand-alone project. This chapter first describes the characteristics of each project, describe how the study was carried out and discuss the other inputs to the study.

4.2 Project Characteristics

A study of the literature and existing projects was completed to determine a reasonable range of high level project features, i.e. capacity and storage capacity. This was done in order to create a set of projects that would accomplish one of the goals of this thesis, determining if larger projects have diminishing returns. Based on this study, which can be found in Chapter 2, Table

10 contains the set of projects chosen to cover a reasonable range of characteristics for the stand-alone projects.

Table 10: Representative Set of Capacity (MW) and Storage (MWh) for Stand-Alone Projects

1. 100 MW, 200 MWh	4. 500 MW, 1000 MWh	7. 1500 MW, 3000 MWh
2. 100 MW, 1000 MWh	5. 500 MW, 5000 MWh	8. 1500 MW, 15000 MWh
3. 100 MW, 2000 MWh	6. 500 MW, 10000 MWh	9. 1500 MW, 30000 MWh

In addition, the Mica Extension project was considered using economic and technical information obtained from (Hatch, 2010). Since storage has been defined as the maximum amount of energy that can be generated by emptying the reservoir at full capacity, storage the Mica extension will be an awkward comparison with the stand-alone projects. The reservoir impounded by Mica Dam, known as Kinbasket Lake, has a live storage volume of approximately 15 x 10^9 m^3 of water. By applying the same methodology as that of standalone projects, generating using only the reversible pump-turbines, this results in energy storage of approximately 7,200 GWh. This is orders of magnitude higher than the stand-alone projects described in Table 10 which have a maximum of 30 GWh of storage. In addition, Mica Dam is not a greenfield site and much of the infrastructure has already been developed resulting in lower costs. The operation of Mica Dam will be much more tightly constrained than the stand-alone project due to water license and treaty obligations. The following sections will outline the technical parameters of the studies.

4.2.1 Upper Deserted to Unnamed

The scope of work for this section is to determine if there is a site in BC that could reasonably contain all the projects listed in Table 10. At this point the intention is not to determine if the selected site is economically or technically feasible, nor to determine final design parameters. The site was chosen from the list of projects near the Lower Mainland from (Knight Piésold Consulting, 2013), that provided a screening assessment for PHS potential in British Columbia. Only closed-loop sites were considered for this study that did not have a hydraulic connection to existing hydroelectric projects. The site was chosen from the subset list that included projects with a power capacity of 1,000 MW capable of storing 6,000 MWh of energy. The screening criterion for choosing the test site consisted of an estimate of the vertical heights of dam needed to contain the largest project in Table 10. This characteristic is likely to be a large cost driver and thus a reasonable project must have a reasonable dam height. The rationale was that if the site can reasonably contain the largest project then it can contain the smaller ones.

The height of dam required to store the water corresponding to the various projects was estimated by assuming that the shape of each reservoir can approximated using a truncated cone. This shape can only be assumed above the existing lake water level in the lake and it is assumed for the purposes of this study that drawdown below the existing water level is unacceptable and unavailable for use for power generation. This assumption is reasonable as the detailed design of the dam is beyond the scope of this thesis and the shape captures the essence of a non-linear relationship between increasing storage volume with dam height. This approximation carries the following two assumptions: that the slope of the constructed dam would be constant in the range above the existing water level, and that the shape of the reservoir's area is circular.

4.2.1.1 Reasonability Test

This section explains through the calculations for the chosen site "Upper Deserted to Unnamed Lake", the location of which is shown in Figure 21 below.

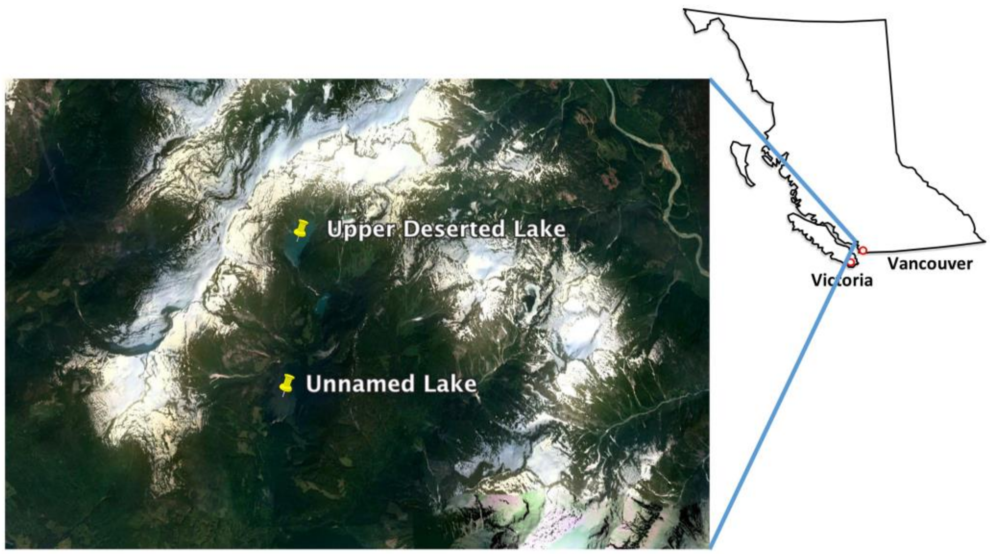

Figure 21: Location of Upper Deserted Lake

Source: (Google Earth, YourFreeTemplates)

In order to determine the maximum height of the dam, the maximum flow rate required for the largest capacity scenarios (1500 MW) was estimated using Equation 15. It is assumed, in the initial suitability stage, that the additional capacity from 1000 to 1500 MW could be achieved by adding additional identical pump-turbine units with the same efficiency and other characteristics. The volume of water required for the largest project was then determined by calculating the volume of water needed to pass the maximum amount of flow (for 1500 MW) for the maximum amount of time (20 hours) using Equation 16. The original parameters for the Upper Deserted to Unnamed Lake project are shown in Table 11.

$$P = \rho g h Q \eta$$

Equation 15: Basic Equation for Power

Where,

$g = 9.81$ m/s^2

$\rho = 1000$ kg/m^3

P = Power capacity (W)

h = Gross head (m)

η = Overall efficiency in generation mode

Q = Design flow in generation mode (m^3/s)

$$V = Q * t$$

Equation 16: Required Water Volume for Project

Where,

V = Volume of water required for project (m^3)

Q = Design flow in generation mode (m^3/s)

t = Required time at power capacity (s)

Table 11: Parameters for Upper Deserted to Unnamed Lake

Parameter*	**Value**
Gross Head	727 m
Power Capacity	1000 MW

Design Flow (Generation)	183 m^3/s
Design Flow (Pumping)	128 m^3/s

*Source: (Knight Piésold Consulting, 2013)

In order to determine the required dam height, the shape and dimensions of the reservoir were simplified to resemble a truncated cone as shown in Figure 22.

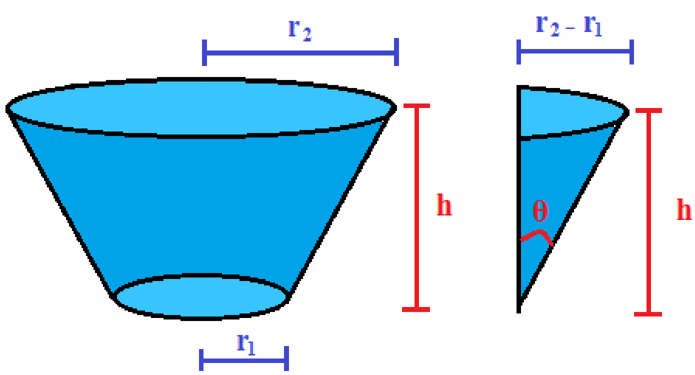

Figure 22: Approximation of the Shape of Reservoirs as a Truncated Cone

The area of the existing lake was estimated using Google Earth as shown in Figure 23. Both the radius of the existing lake and that of the reservoir formed by the dam in Table 11 were found by rearranging the equation for the area of a circle, as shown in Equation 17.

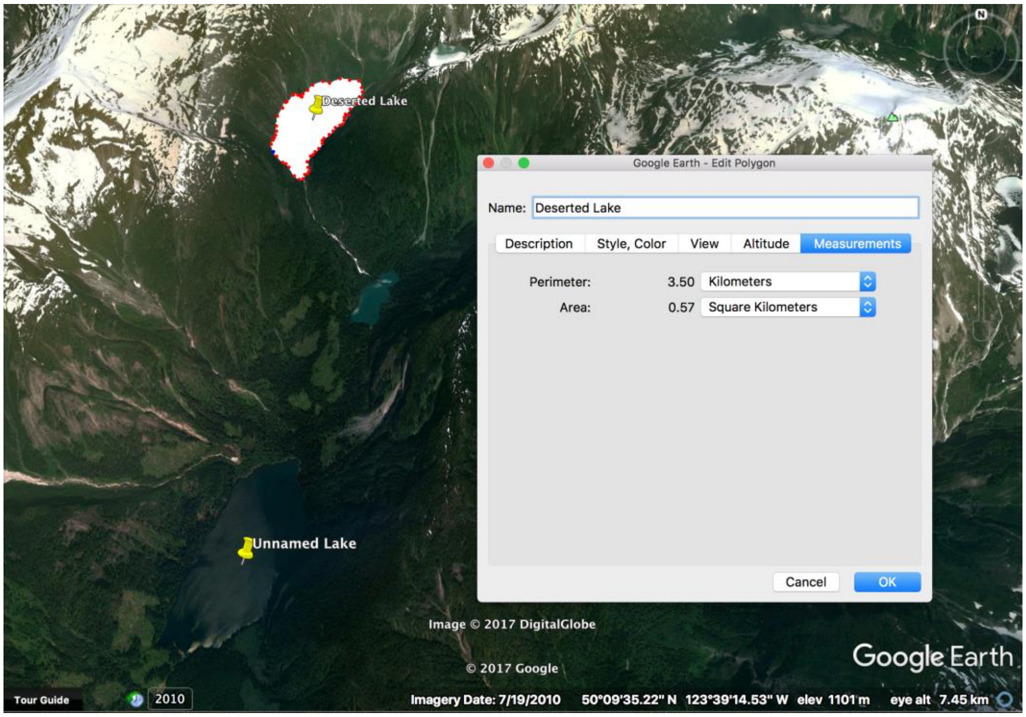

Figure 23: Upper Deserted Lake Area from Google Earth

$$r = \sqrt{\frac{A}{\pi}}$$

Equation 17: Radius of Circular Lake or Reservoir

Where,

r = Radius of lake or reservoir (m)

A = Area of lake or reservoir (m^2)

The radius of the full reservoir and existing lake were then used in conjunction with the height of the dam to determine the approximate slope of the impoundment used in Table 11. This was done in order to consider the radius of the new reservoir as a function of the dam height and the radius of the existing lake as shown in Equation 18.

$r_2 = \tan(\theta)\, h + r_1$ **Equation 18: r_2 as a Function of r_1, h and θ**

Where,

r_2 = Radius of full reservoir (m)

θ = Slope of reservoir impoundment (radians)

h = Dam height (m)

r_1 = Radius of empty reservoir (m)

Next, Equation 18 was substituted into Equation 19 to finally have an equation for the volume of a truncated cone as a function of the existing lake radius (r_1), slope of the impoundment (θ) and the height of the dam (h).

$$V = \frac{1}{3}\pi(r_1^2 + r_1 r_2 + r_2^2)h$$

Equation 19: Volume of a Truncated Cone

Where,

V = Volume required (m^3)

r_1 = Radius of empty reservoir (m)

r_2 = Radius of full reservoir (m)

h = Height of impoundment (m)

The Goal Seek tool from Excel was used to calculate the height of dam needed to contain the volume of water found using Equation 16. This process was done for the upper reservoir (Upper Deserted Lake) as well as the lower reservoir (Unnamed Lake). A summary of the estimated parameters is shown in Table 12.

Table 12: Summary of Estimated Parameters for Upper Deserted Lake Study

Parameter	Value
Capacity	1500 MW
Design Flow	274.5 m^3/s
Volume Required	19,764,000 m^3
Slope of Impoundment	32°
Required Dam Height	33 m

This height was compared to the average, minimum, and maximum dam heights for projects listed in (Knight Piésold Consulting, 2013). It is expected that this project will have a larger dam height as it has a higher storage requirement, i.e. maximum flow for 20 hours rather than 6 hours from the Knight Piésold report. The estimated dam height of 33 m is higher than the average of 16 m, but it is still well below the maximum dam height of 63 m which was included in the report and thus it was deemed a reasonable project. In addition, to test the assumption of the shape being approximated by a truncated cone, a elevation profile was drawn across the reservoirs using Google Earth and it was verifed that the slope is relatively constant in the elevations within the range of the estimated dam height. To reiterate, the objective of this section is to determine if there is a site in BC that could reasonably contain the largest project. Once the site has passed the reasonability test, general project parameters for all of the test cases can then be estimated.

Based on the estimated maximum dam height, the Upper Deserted to Unnamed Lake was deemed to be reasonable and satisfies the requirements of this screening process. It fulfils the question of whether there is a potential PHS site that can reasonably contain projects with characteristics listed in Table 10. In addition, this particular site is favorable because of the relatively high elevation difference between the two lakes as well as the fact that it is non-salmon bearing water body and is not a source of drinking water (Knight Piésold Consulting, 2013). The gross head between the reservoirs is 727 m compared to the average of 560 m from the Knight Piésold report. Based on (American Society of Civil Engineers, 1989), high head projects tend to be favorable from a cost perspective.

4.2.1.2 Storage Elevation Curve

In order to create input parameters for the projects a relationship between the amount of water in storage and the vertical level of water in the reservoir had to be assumed for the upper and lower reservoirs. This vertical level is referred to as the forebay level. Each reservoir has a unique relationship between the forebay level and quantity of water impounded, known as the storage elevation curve. Since this is a hypothetical project where capturing the essence of the characteristics is more important than specific values, it was assumed that this relationship could again be approximated with a truncated cone. The essence that was intended to be captured was the non-linear increase in storage with increasing forebay. Although other shapes could have been used to capture this behavior (i.e. truncated square pyramid or lower section of a sphere), the truncated cone was chosen because it uses both properties of a circle and a constant slope. The approximation of using a constant slope is only valid when assuming a dam will impound the reservoir, and when trying to characterize the storage elevation relationship for a small section.

The storage elevation curve is a piecewise linear curve that consists of a set of breakpoints with an associated forebay and quantity of water. This curve is ultimately used in many ways in the optimization, including the forebay constraints and to reconcile the mass balance with the production curves. For the purposes of this study it was again assumed that the live storage, i.e. water that could be used, was strictly above that of the natural lake level. The natural lake level fluctuates depending on natural inflows, however for the purposes of this study it was assumed to be static. The natural lake level was chosen to be the first breakpoint of the storage elevation curve and had an associated quantity of storage of 0 m^3. The forebay elevations associated with the natural lake level for both reservoirs is shown in Table 13.

Table 13: Natural Lake Levels of Upper Deserted Lake and Unnamed Lake

Reservoir	Natural Lake Level (m.a.s.l.)
Upper Deserted Lake	976 m
Unnamed Lake	248 m

The storage elevation curve for the lower reservoir, Unnamed Lake, is shown in Figure 24. The following process was used to determine the forebay elevation curve for both Upper Deserted and Unnamed Lake:

1. Determine slope of reservoir
2. Determine volume of water needed for largest potential project
3. Determine forebay level that coincides with the volume of water from Step 2
4. Discretize forebay between the natural lake level and the maximum forebay level from Step 3 using 6 points
5. Calculate volume of water for each forebay level

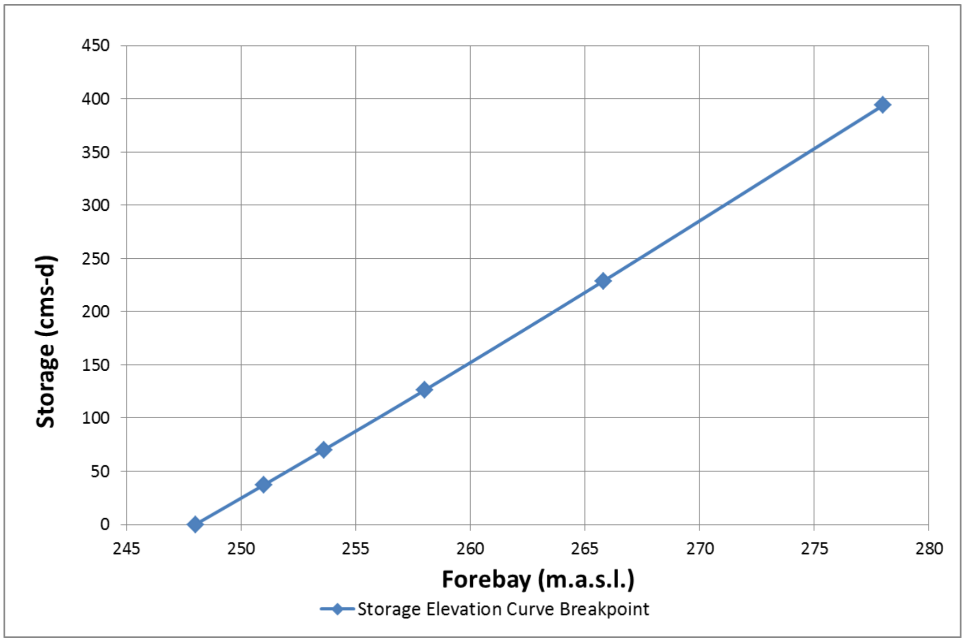

Figure 24: Unnamed Lake Storage Elevation Curve

4.2.1.3 Limits on Flow and Power

The purpose of this section is to explain how the limits for flow and power were determined for each case investigated. As described in Chapter 3, the flow and power in pumping mode are expressed as negative values. When the PHS plant is releasing water from the upper reservoir and generating electricity, both flow and power values are positive. When the PHS plant is pumping water from the lower reservoir to the upper reservoir and consuming electricity, both flow and power values are negative. There is a simple relationship that bounds the amount of water that can be used to generate or be pumped given the elevation difference between the reservoirs, and the efficiency and rating of the units. A larger elevation difference between reservoirs, i.e. the upper reservoir at a higher forebay level, will require less water to be released to generate the same amount of power. However in pumping mode, a larger elevation difference will require more power to pump the same amount of water. There are therefore limits on the maximum generation or maximum pumping flow and power relationship unique to each forebay level across the feasible range.

The charge to discharge ratio is defined as the ratio of the average electrical input when pumping to the electrical output when generating (American Society of Civil Engineers, 1989). A value of 1 was chosen for this study as these values typically vary between 0.9 to 1.2 for reversible Francis units (American Society of Civil Engineers, 1989). This means that for a 100 MW project, the maximum power that can be used by the pump and the maximum amount of power that can be generated by the turbines is 100 MW. The implication for fixing this ratio is that at each forebay level the amount of maximum power that can either be used to pump or that can be generated is the same while the associated amount of water pumped or released is different.

In order to determine the efficiency of the units in pump and generation mode, a back calculation was performed on values from (Knight Piésold Consulting, 2013) and compared with the literature. The back calculation for the Upper Deserted to Unnamed Lake plant uses Equation 15 with Table 11 as shown in Equation 20 for generation mode and Equation 21 for pumping mode.

$$\eta_{gen} = \frac{P}{\rho g h Q}$$

Equation 20: Efficiency in Generation Mode

Where,

η_{gen} = Overall efficiency in generation mode

P = Power capacity = 1000 MW

ρ = 1000 kg/m^3

g = 9.81 m/s^2

h = Gross head = 727 m

Q = Design flow for generation =183 m^3/s

$$\eta_{pump} = \frac{\rho g h Q}{P}$$

Equation 21: Efficiency in Pumping Mode

Where,

η_{pump} = Efficiency in pumping mode

P = Power capacity = 1000 MW

ρ = 1000 kg/m^3

g = 9.81 m/s^2

h = Gross head = 727 m

Q = Design flow for pumping =128 m^3/s

It is important to note that the efficiency factor is applied in a slightly different way in the generation mode as compared to the pumping mode. In the generation mode the efficiency reduces the amount of power that can be generated by a certain amount of flow, and in the pumping mode the efficiency increases the amount of power needed to pump a certain amount of water. The unit efficiency for pumping mode and generating mode was found to be 92% and 77% respectively. Although these values appear to be low relative to generator units, they reflect friction losses in the penstock as well as the fact that pump-turbine units typically have a lower efficiency than dedicated pump or turbine units (Çengel & Cimbala, 2006). The efficiency in generating mode will also be affected by the amount water passing through the turbines, known as the tailwater effect. The magnitude of this effect was replicated on the test cases based on the tailwater effect present at other BC Hydro plants.

The flow and power limits for the lower reservoir were set to zero to simulate the case with would have no powerhouse. The forebay of the lower reservoir was fixed as average value during this process because the maximum fluctuation is small relative to the elevation difference between reservoirs. The following process was used to determining the flow and power limits and an example is shown for the 1500 MW case in Figure 25 and Figure 26 below:

1. Discretize the forebay of the upper reservoir in increments of 3 m from the natural lake level to the highest possible level
2. For each capacity (1500 MW, 500 MW and 100 MW) determine the scaled efficiency based on the expected tailwater effect
3. For each upper reservoir forebay calculate the flow required to achieve the capacity as shown in Figure 27

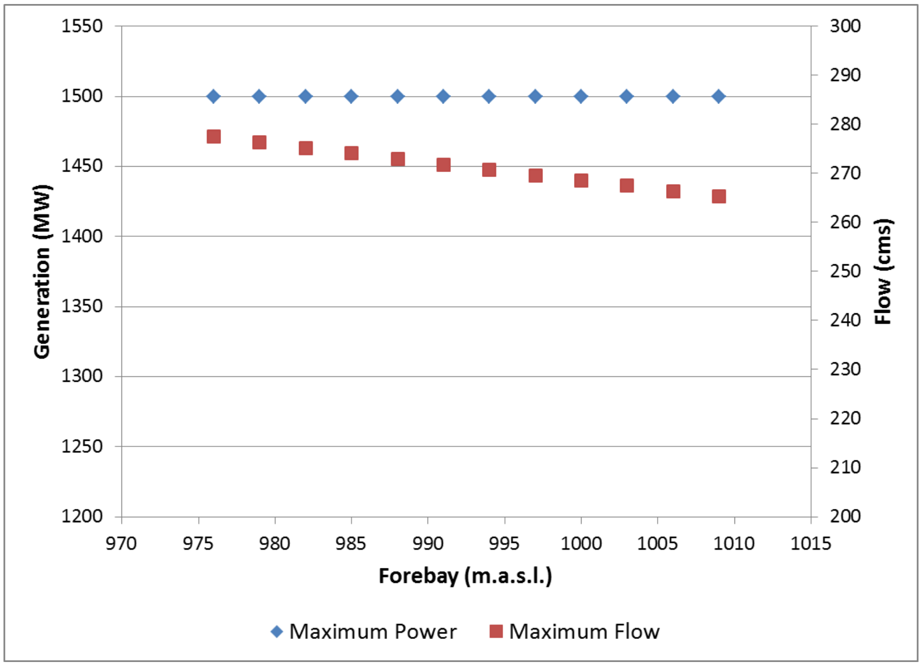

Figure 25: Upper Deserted Generation Mode Flow and Power Limits as a Function of Forebay for 1500 MW Case

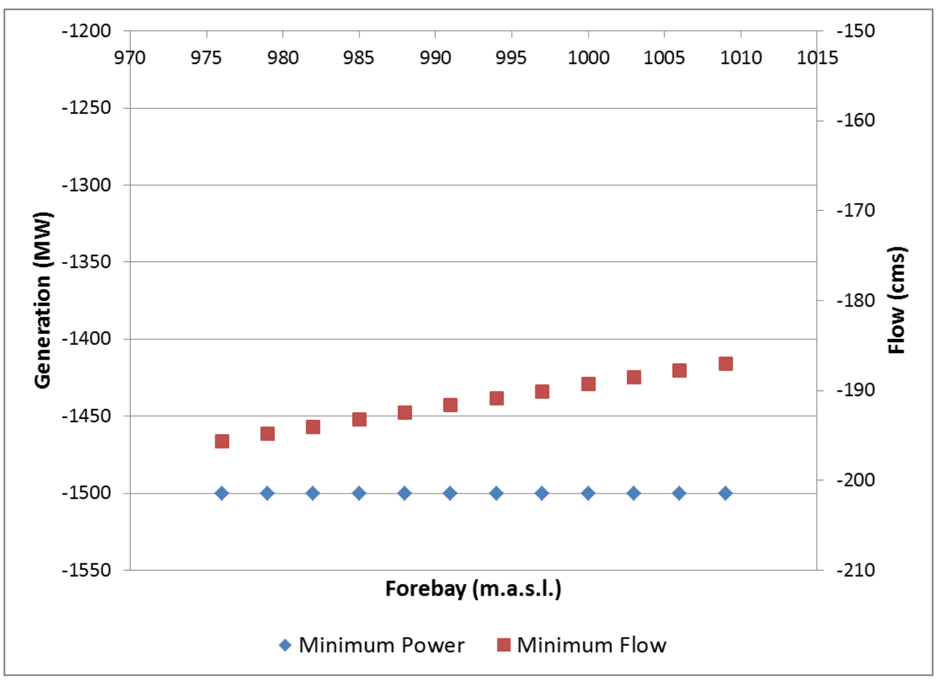

Figure 26: Upper Deserted Pump Mode Flow and Power Limits as a Function of Forebay for 1500 MW Case

Capacity	500	MW
Max Efficiency	0.7825	
FB (m.a.s.l)	**Power (MW)**	**Flow (cms)**
976	500	90.58
979	500	90.20
982	500	89.83
985	500	89.46
988	500	89.09
991	500	88.73
994	500	88.37
997	500	88.01
1000	500	87.65
1003	500	87.30
1006	500	86.95
1009	500	86.60

Capacity	-500	MW
Max Efficiency	0.92	
Max FB	Power (MW)	Flow (cms)
976	-500	-65.21
979	-500	-64.94
982	-500	-64.67
985	-500	-64.40
988	-500	-64.14
991	-500	-63.88
994	-500	-63.62
997	-500	-63.36
1000	-500	-63.10
1003	-500	-62.85
1006	-500	-62.60
1009	-500	-62.35

Figure 27: Upper Deserted Flow and Power Limits as a Function of Forebay for 500 MW Case

4.2.1.4 Production Curves

In hydropower engineering, there is an important characteristic that is unit or plant specific referred to as the Hydro Power Generation (HPG) curve (Shawwash, A Decision Support System For Real-Time Hydropower Scheduling in a Competitive Power Market Environment, 2000). The HPG curve is a production function that is extremely important for the economic dispatch of hydroelectric plants (Shawwash, Planning of the BC Hydro System: Modelling Frameowrk and Decision Support Tools, 2014). The function of this characteristic is to specify the amount of power that can be generated with a specified flow with a certain amount of head between the upper and lower reservoir. One can imagine that with a higher head, more power can be generated with the same amount of water. This concept is similar but opposite in the pumping mode; more power needs to be used to pump the same amount of water with a higher head. In order to use these curves in the optimization model, a requirement was to ensure that these curves are piecewise linear and convex. An example of the HPG curve at a specified upper reservoir forebay is shown in Figure 28. Although there was an HPG curve for the Unnamed Lake in the inputs to the model, all points were set as zero because there is no generation or pumping capacity.

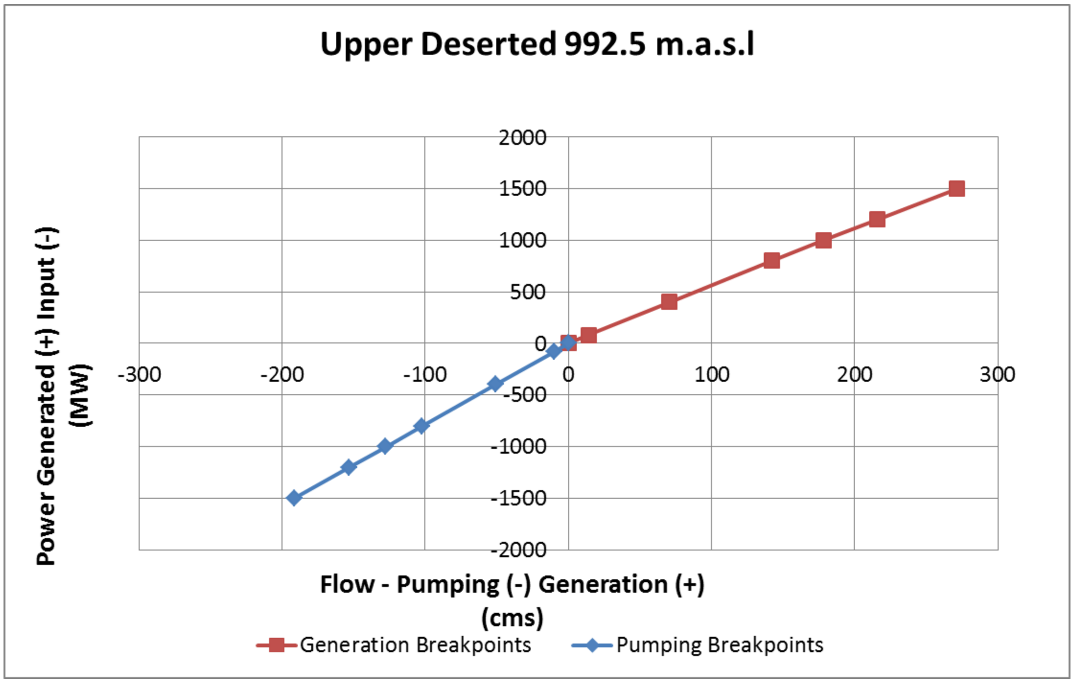

Figure 28: Example HPG Curve for Hypothetical Upper Deserted – Unnamed Lake Project

The HPG curve was assumed to only be a function of the forebay of the upper reservoir, which is assumed to be reasonable at this level of modelling for a hypothetical project. This means that the head for the power equation is only a function of the forebay of the upper reservoir, not the lower reservoir. These curves are discretized with breakpoints that indicate the peak efficiencies of unit combinations. The reason these points are chosen for the discretization is because in linear programming the solution tends towards vertices and it is likely that operators of the plant will operate at peak efficiency points. In this study, 13 breakpoints were chosen that discretized the full range of power input or generation output. These breakpoints were chosen on the basis of reasonable unit sizes in consideration of the tests for this thesis outlined in Table 10. The peak efficiency in generation mode at higher flows is anticipated to be slightly lower to account for a tailwater effect. The magnitude of this effect is small but still significant and was estimated using data from BC Hydro. There is no tailwater effect on the pumping side of the HPG curve. The curve itself is continuous between pumping and generating mode, passing through the origin to ensure there is no situation where power can be generated without any water being released. These breakpoints or peak efficiencies are also a function of forebay. In order to incorporate this in GOM, the HPG curve is a function of generation and flow breakpoints which are further a function of forebay. The generation breakpoints were fixed for this study meaning that the flow within the penstock is assumed to be able to be adjusted to maintain the same generation. In order to calculate the function that represents the breakpoints as a function of forebay, the flow for a given amount of generation was calculated for three forebays and a linear regression line was calculated. The three forebays that were chosen for the regression were the maximum, minimum and their average, i.e. mid. An example of one of these breakpoints is shown in Figure 29. The curve created and used in this thesis is not a perfect representation of a final design of a PHS plant and more detailed engineering design will be required.

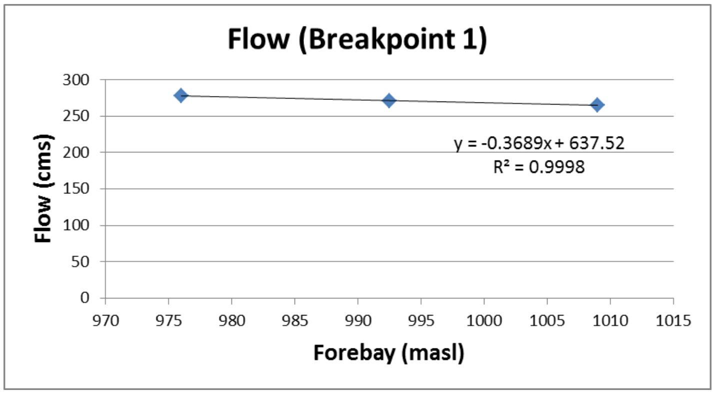

Figure 29: Example HPG Breakpoint Regression Line

4.2.1.5 Forebay Limits

The forebay limits are used to satisfy the storage requirement for each test case. This was used as the flow limits and storage are both functions of the forebay. Storage is defined by the quantity of water needed in order to run the plant at maximum generation capacity for a certain number of hours. The storage is effectively limited by limiting the forebay by an upper bound. In all cases, the lower forebay limit was set to the natural lake level. The upper forebay limits were calculated using the truncated cone approximation in conjunction with the HPG curves described above. The following process was used to calculate the maximum forebay for each test case and an example for the 1500 MW case is shown in Figure 30:

1. Convert the rated capacity to maximum generation flow using the average head value
2. Calculate the maximum volume of water required using the time requirement (2, 10, 20 hours)
3. Calculate the height of truncated cone required as shown in Figure 22 using the Goal Seek tool in Excel

4. Add the height to the Natural Lake Level as shown in Table 13 to obtain maximum forebay

Rated Capacity	1500	MW					
Max Flow	271.30	cms	Using HPG Curves Excel Sheet - Average Head Value				
t Requirement (hrs)	2	10	20				
V Required (m^3)	**1953360.00**	**9766800.00**	**19533600.00**				
h (using goal seek) - (m)	**3.41**	**16.72**	**32.66**				
Max FB (masl)	**979.41**	**992.72**	**1008.66**				

Figure 30: Maximum Forebay for 1500 MW Test Cases

The forebay limits for the 1500 MW 30000 MWh case are shown below in Figure 31. As shown, the initial and final forebay was set equal to 80% of the maximum for each test cast. That is 80% between the upper and lower limits. This starting and ending forebay was varied and deemed not to have a significant impact on the results. Fixing the initial and final forebay is a technique used by BC Hydro for medium to long term studies to prevent the reservoir from fully draining every year. Since no natural inflows were included it made sense to have a net zero change of storage volume between the upper or lower reservoirs.

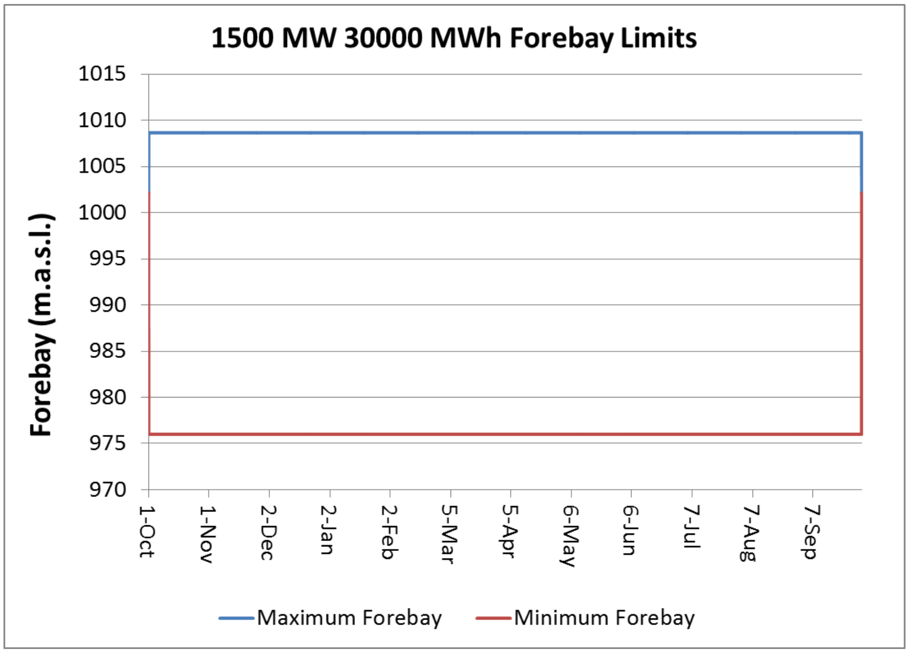

Figure 31: Forebay Limits for 1500 MW 30000 MWh (20 hours) Project

4.2.2 Mica Project

Mica Dam is located north of Revelstoke BC along the Columbia River as shown in Figure 32. The addition of pumped storage at the Mica Dam was included as one of the resource options in the 2013 IRP as described in previous chapters. Two configurations were considered for including pumped storage: extending the existing powerhouse on the right bank and adding a new facility on the left bank. Due to technical complications with construction on the right bank, the left bank configuration was deemed favorable. The technical complications included the requirement of excavating a significant amount of rock beside existing units. A conceptual drawing of the left bank configuration is shown in Figure 33 below.

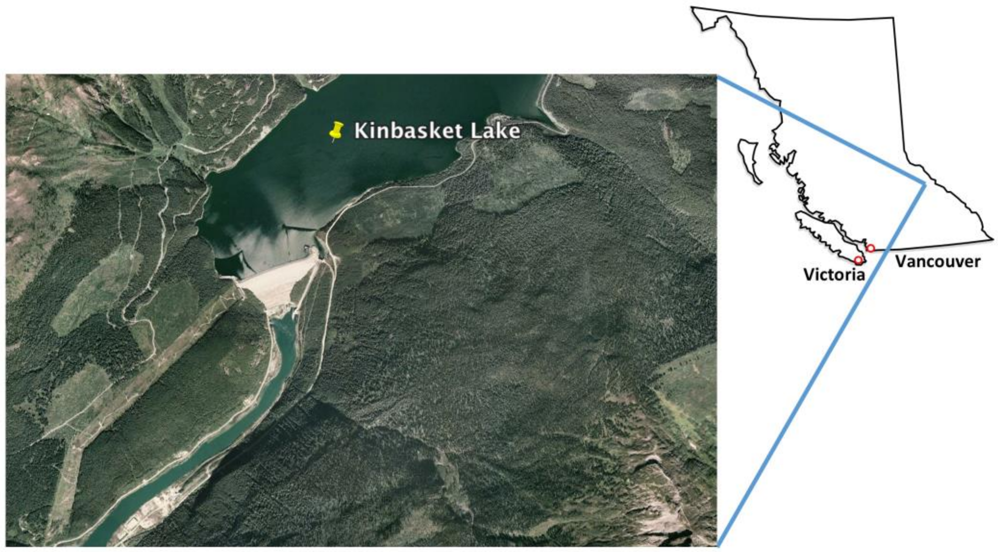

Figure 32: Location of Mica Dam

Source (Google Earth, YourFreeTemplates.com)

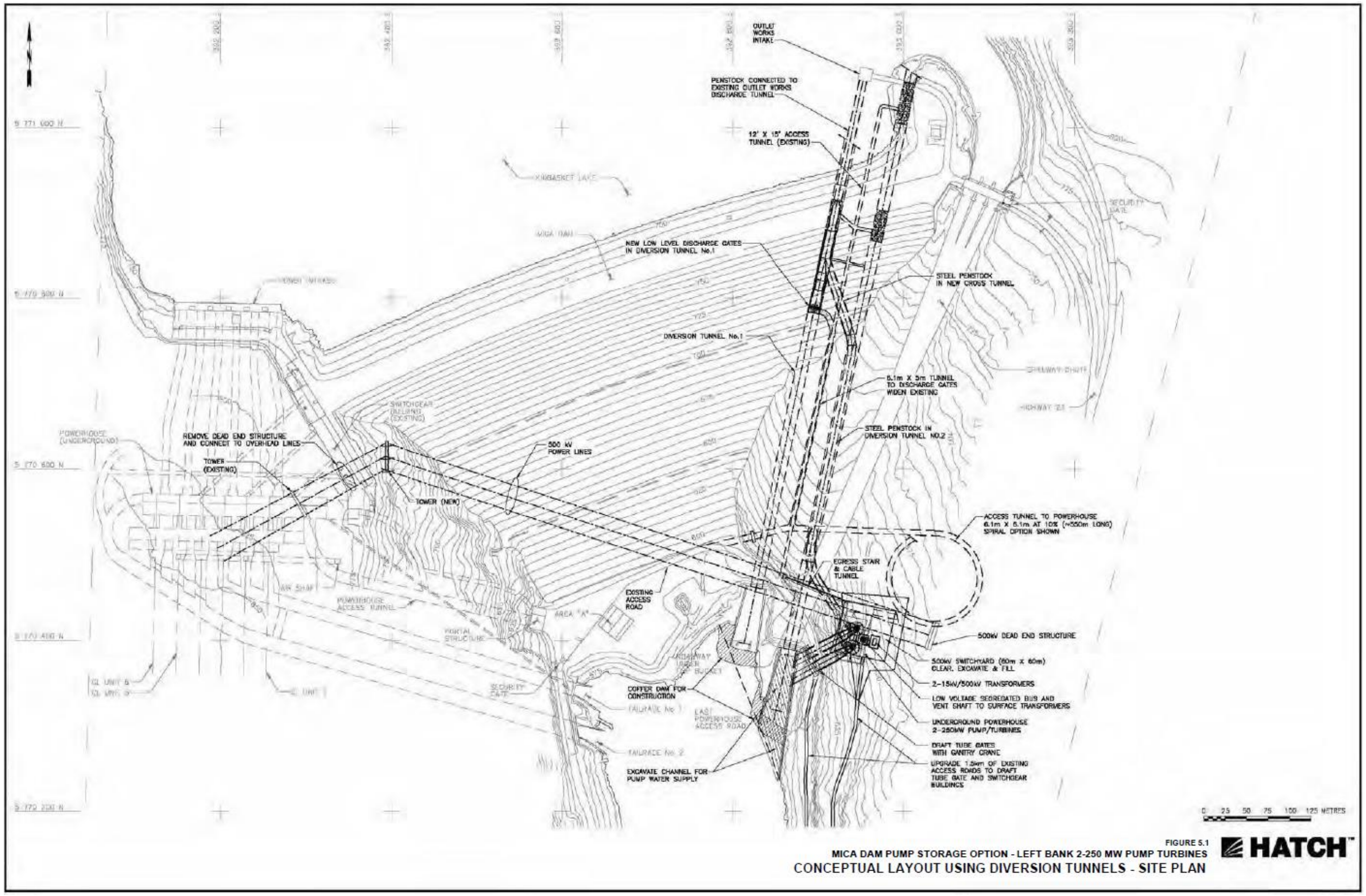

Figure 33: Location of Mica Dam Pumped Storage Option - Left Bank

Source (Hatch, 2010)

As described in Chapter 2, the rationale behind this location was to take advantage of the large reservoir, Kinbasket Lake, to manage freshet flows at Revelstoke. As shown in Figure 34, Revelstoke Lake receives the majority of its inflows between the end of May and beginning of August. These inflows are primarily due to the melt of the snowpack in the catchment. Managing the operation of the Revelstoke plant is challenging during this period of the year due to low electricity prices and constraints for Revelstoke Lake. This water could be pumped from Revelstoke Lake to the much larger Kinbasket Lake during a time when electricity is inexpensive, to be used to generate electricity during times of scarcity. Reversible pump-turbine units would also be able to provide additional peak generating capacity at the Mica plant.

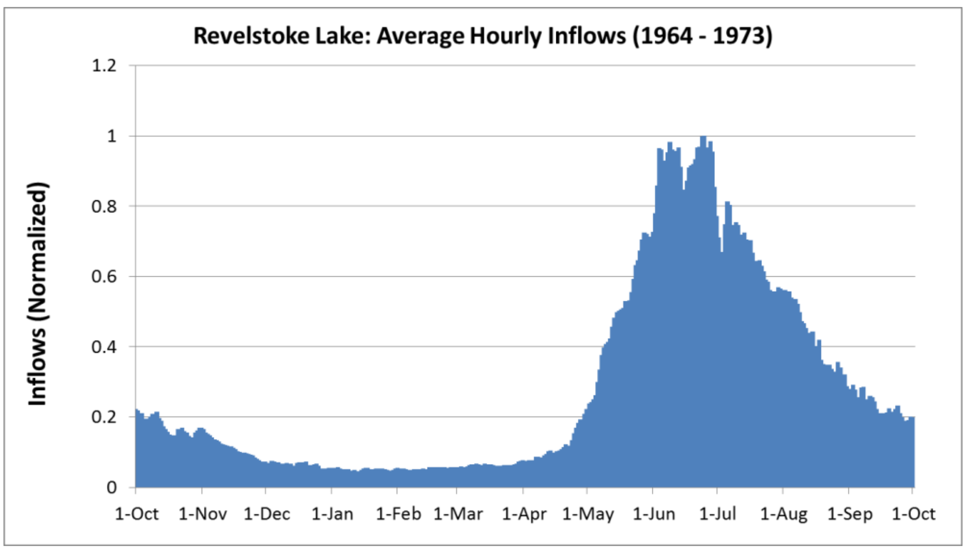

Figure 34: Average Natural Inflows to Revelstoke Lake (1964 to 1973)

Source (BC Hydro Internal)

4.2.2.1 Production Curves

In GOM the planning of the operation of plants occurs at the plant level. The total generation and flow for a plant is determined, rather than for individual units. When more than one unit is operational, the HPG curve is formulated such that it is representative of the combination of units. The configuration that was chosen for this study was two variable speed pump-turbine units with a nominal generation capacity of 500 MW. For the purposes of this study, the two additional pump-turbine units were treated in GOM as operationally separate from the rest of the units in the Mica Generation Station. Thus, this combination of pump-turbine units had its own HPG curve as shown below in Figure 35, referred to as the Mica Extension Project. This figure shows the HPG curve at one forebay, however in reality each of these breakpoints are linear functions of the forebay. As explained in the previous section, the HPG curve is a function of head between the upper and lower reservoir. In this case since the variation in Revelstoke Lake is relatively small the HPG curve is only a function of Mica Dam’s forebay. This production curve was estimated using information from (Hatch, 2010) and a sample curve for the efficiency for each breakpoint is shown in Figure 36. Much more detailed technical information was available for this project as compared to the Upper Deserted – Unnamed Lake project.

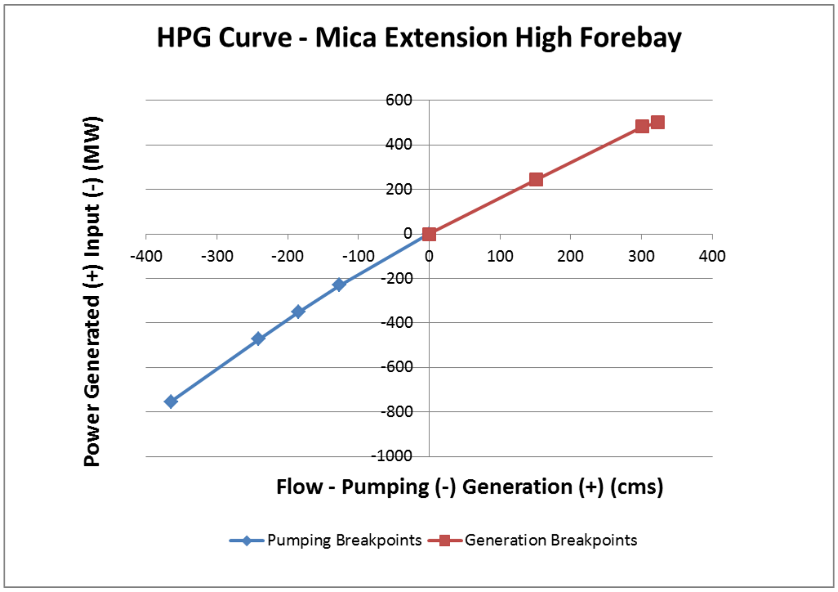

Figure 35: Example HPG Curve for Mica Extension Project

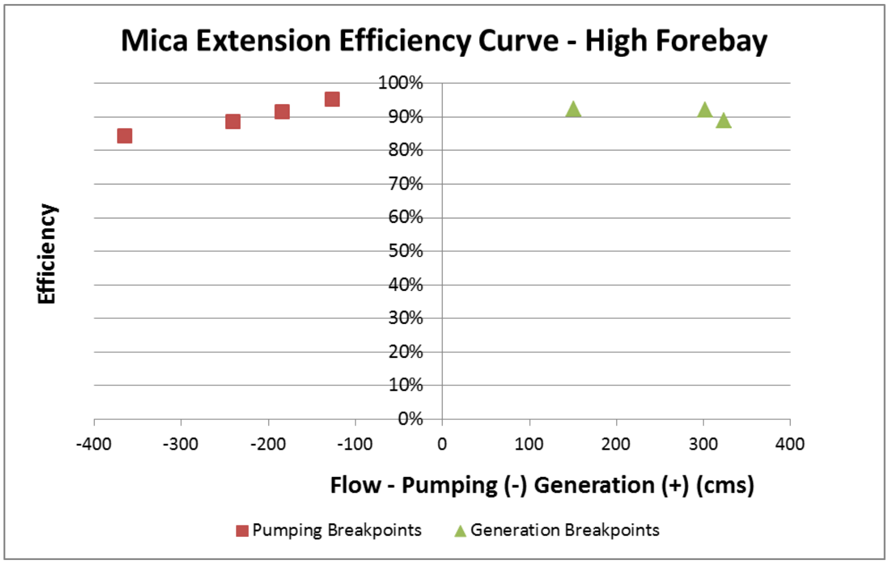

Figure 36: Sample Efficiency Curve for Mica Extension

4.2.2.2 Flow Limits

The limits on the maximum turbine and pumping flow are a function of Mica Dam's forebay level. These limits were extrapolated from information found in (Hatch, 2010). To calculate these limits Mica Dam's forebay was discretized and the quantity of water needed to generate the nominal amount of power (500 MW) and amount of water that can be pumped was calculated using the reversible pump-turbine characteristics. These limits are shown graphically in Figure 37. As expected, the water required for generation decreased with increasing forebay and the water that can be pumped with the same power decreased with increasing forebay.

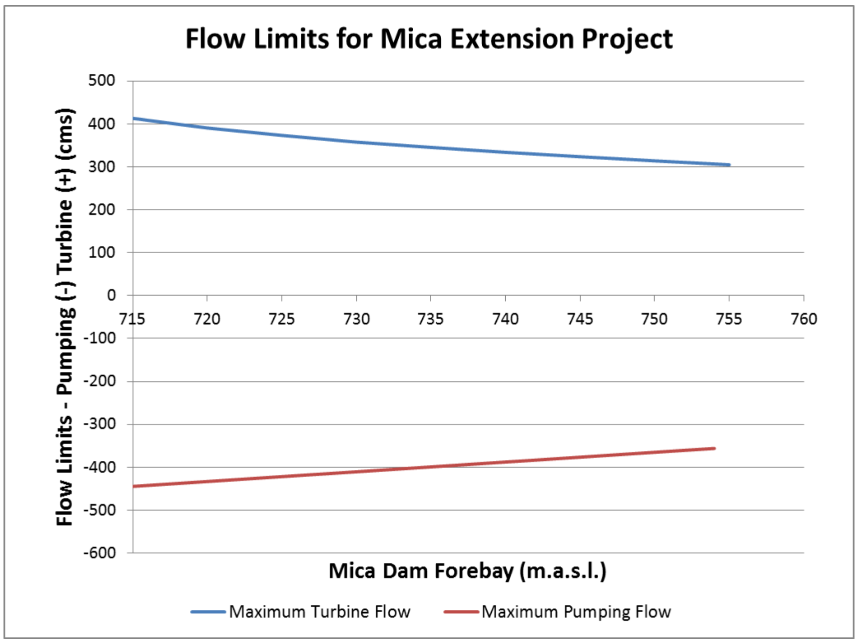

Figure 37: Flow Limits for Mica Extension Project

4.2.2.3 Storage Elevation

The storage elevation curve for the plant representing the reversible pump-turbine units was set the same as Kinbasket Lake. The forebay for this plant at each timestep was set the same as for Mica Dam. This way, the HPG curves and flow limits are updated each time Mica's forebay changes.

4.2.2.4 Forebay Limits

Part of the extensive planning process that occurs at BC Hydro includes creating monthly forebay targets for the large plants. These targets constrain the forebay to create an approximate yearly trajectory of storage in the reservoir for each year. Since there is already a trajectory for Mica Dam's forebay, the monthly limits for the forebay for the Mica Extension Project were relaxed. These limits were set as the absolute minimum and maximum levels, approximately 707 and 754 m.a.s.l. respectively. The minimum and maximum forebay for the Mica Extenstion Project as well as a hypothetical forebay trajectory for Kinbasket Lake are shown in Figure 38 below. This trajectory drafts the reservoir to accommodate inflows during the freshet period and fills up into the fall months.

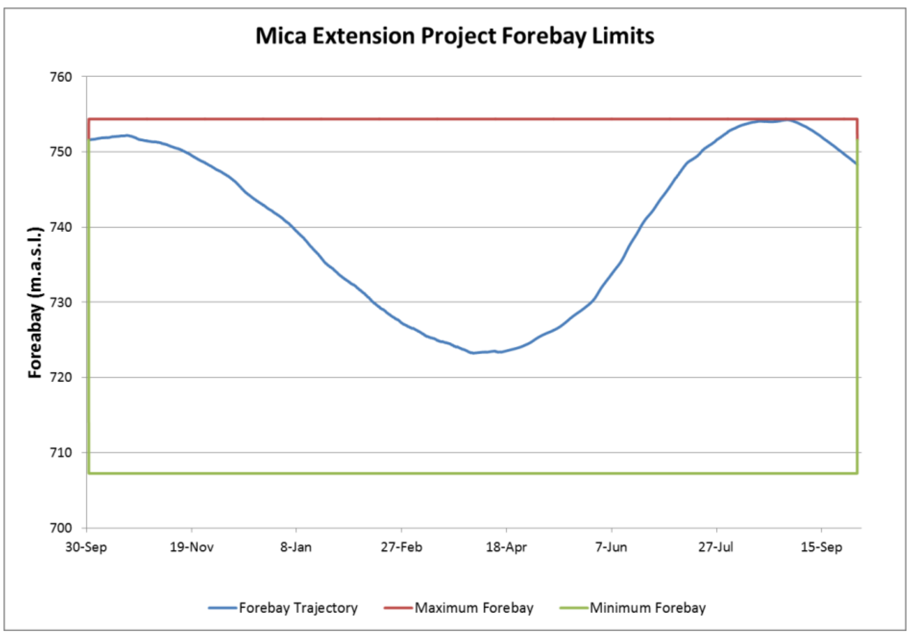

Figure 38: Forebay Limits for Mica Extension Project

4.3 GOM Study

In total there are 10 PHS projects that were evaluated as a part of this case study as shown in Figure 39. These projects consisted of 9 stand-alone projects and one extension of an existing hydro plant. This case study was designed to evaluate the benefit of each project consistently across a range of conditions using GOM. A base case of the BC Hydro system was used consisting of 10 sub-cases representing 10 water years of typical operational conditions. The input parameters for this base case used in GOM were obtained from public documents published by BC Hydro (BC Hydro, 2013). Relevant inputs to this base case are discussed in this section. The base case was updated to include the PHS project and run again over the set of 10 water years as shown in Figure 40. The total number of optimization problems in this case study, including the base case, was 110.

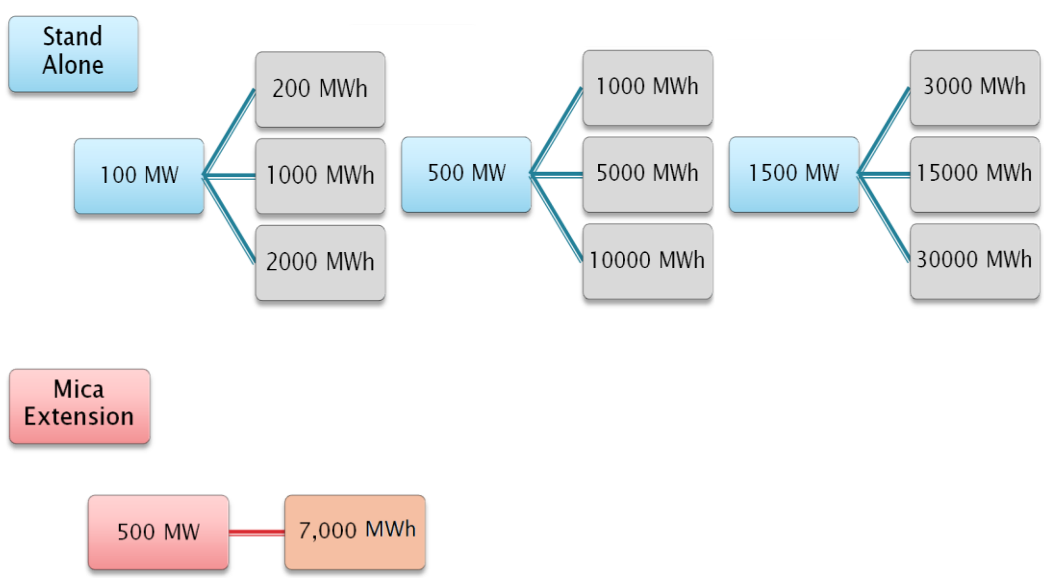

Figure 39: Summary of Projects for Study

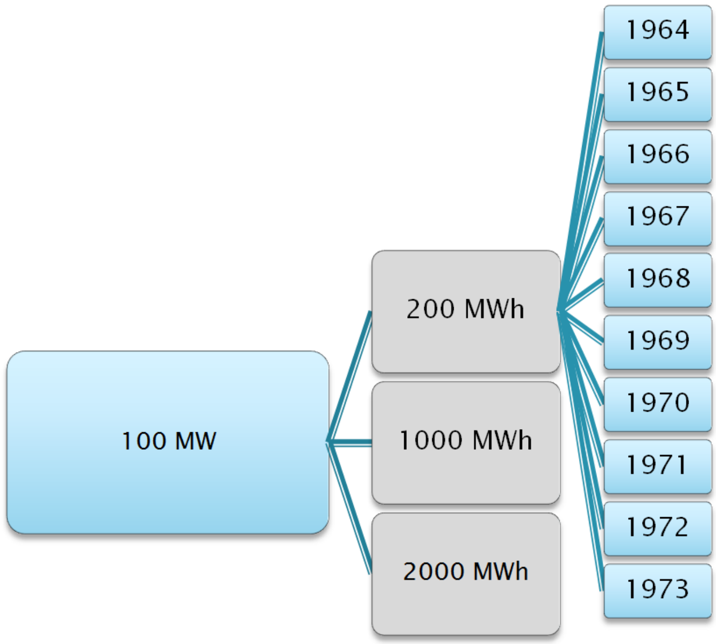

Figure 40: Setup of Study

Certain model inputs were held constant between different years. These inputs include the domestic electricity demand (load), operational constraints of the other optimized hydro assets, and limits on transmission interties with the US and Alberta. The inputs that changed between years included forebay trajectories, market prices, and the inflows to each reservoir. In order to calculate the benefit for each year, the objective function of the base case was compared to the objective function including the PHS project.

4.3.1 Water Years

The BC Hydro system is comprised predominantly of conventional hydroelectric facilities. As one can imagine, the operation of the system is closely tied to the available water or inflows to each project. The availability of water has a major influence on BC Hydro's import or export decision with Alberta and the US. Historical streamflow data is used, with the assumption that streamflow is stationary over the lifetime of the project, in order to represent future variable inflow conditions. Although the full set of historical streamflow data that can be used for modelling is 60 years, the inflows from October 1964 to September 1974 are considered representative as they contain a range of normal, dry and wet water years (BC Hydro, 2013). Unlike the calendar year the water year starts on October 1 and finishes on September 30. The cumulative annual inflows, shown for illustrative purposes, are shown in Figure 41 below. As shown, 1969 is a dry year, 1971 is a wet year and 1968 is a relatively average year. Climate change could potentially impact the viability of these inflows to be representative of future conditions; however that is beyond the scope of this study. These potential impacts should be studied in greater detail if a PHS project is brought to later stages of planning.

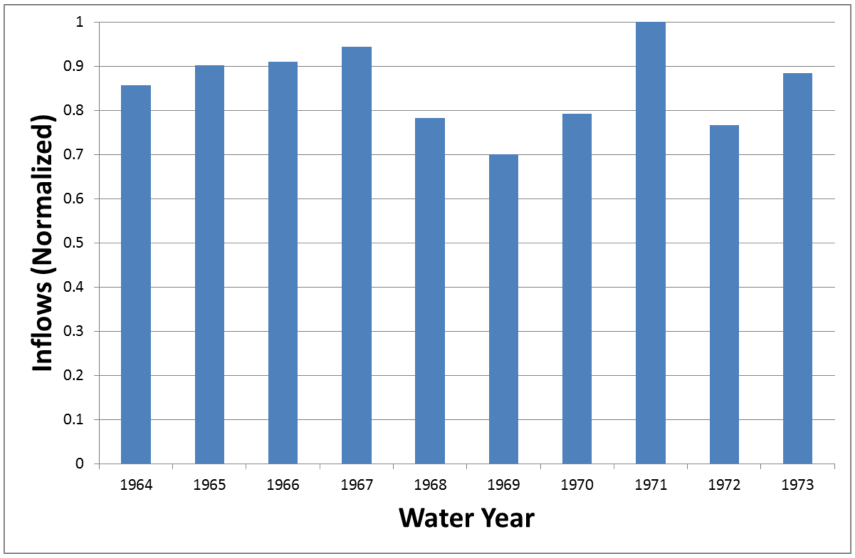

Figure 41: Cumulative Inflows for Optimized BC Hydro Plants

Source (BC Hydro Internal)

4.3.2 Load

The load is a very important input in this study as the objective of GOM is to satisfy domestic load and maximize trade benefits. Under all hydrologic conditions the load must be met before being able to export any energy. The load used in this case study was adapted from an existing BC Hydro study which used information from (BC Hydro, 2013). Forecasting future load conditions is extremely challenging and prone to forecast errors. Factors such as the popularization of electric vehicles could contribute to increasing the load. In contrast, demand side management programs and technological innovations in improving the efficiency of appliances could decrease the load.

In this study the load was left unchanged between different water years. It is assumed that the shape of the load, rather than the absolute value, is sufficient for assessing the benefits of PHS. To illustrate the features of the shape of the load consider Figure 42 and Figure 43, showing the daily and yearly load shape respectively. These figures show the historic BC Hydro load data from January 1st to December 31st, 2017. The daily shape has two peaks: one in the morning when people are getting ready for work in the morning and one in the evening when people are returning from work. The load drops off significantly overnight when people are generally sleeping. The yearly shape generally peaks during the winter months between November and February. The load is lowest between May and July, coincidentally during the freshet period when inflows to the Columbia reservoirs are highest.

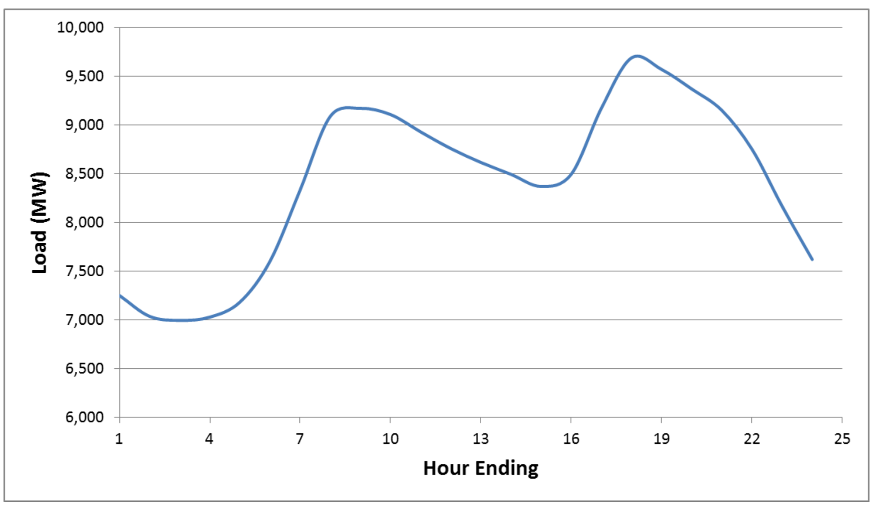

Figure 42: BC Hydro Hourly Domestic Load on December 5, 2017

Source (Historical Transmission Data, 2017)

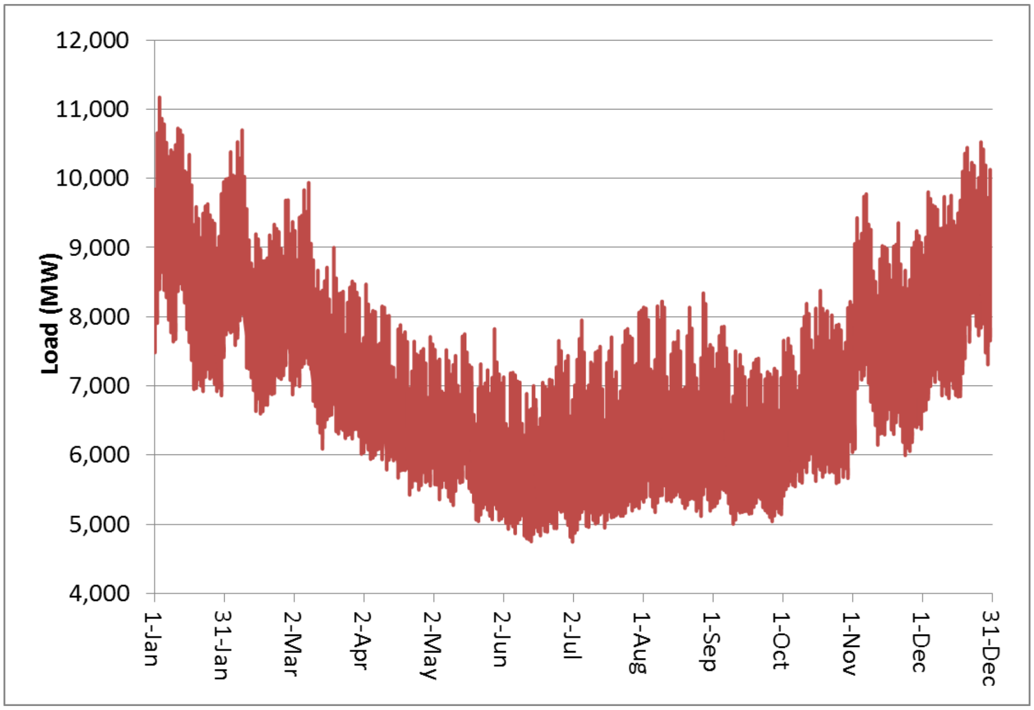

Figure 43: BC Hydro Hourly Domestic Load for 2017

Source (Historical Transmission Data, 2017)

4.3.3 Market Prices

As discussed in previous sections, BC Hydro trades electricity through interconnections with Alberta and the US. Detailed price data used by BC Hydro and its trading subsidiary Powerex remain confidential to maintain competitiveness in the market. The prices used in this study are confidential; however the basis of the prices that were used is discussed in this section. These prices, as indicated in Chapter 3:, include the import and export prices for the Alberta and US markets. BC Hydro normally uses the Mid-Columbia prices as a representative proxy for US prices and AESO prices for Alberta prices. These prices vary by year based on economic and climatic factors, such as the daily temperature and price of natural gas. The electricity price is closely tied to the price of natural gas, as natural gas generation is often the marginal market resource in the merit order (BC Hydro, 2013).

When BC Hydro prepares forecasts of electricity price, they take forecasts of the yearly average price and impose a shape factor to estimate hourly prices. Shown below in Figure 44 is the pool price for the AESO market from 2017 to illustrate such a shape. It is notable that prices in the freshet period, particularly in June, are very low compared to winter months such as January. During this period the prices are low, the load is low, as they are impacted by substantial inflows into BC Hydro's reservoirs. It is expected that the PHS will operate during this time to purchase inexpensive energy and access to a large storage reservoir would allow for the shift freshet flow into the winter months.

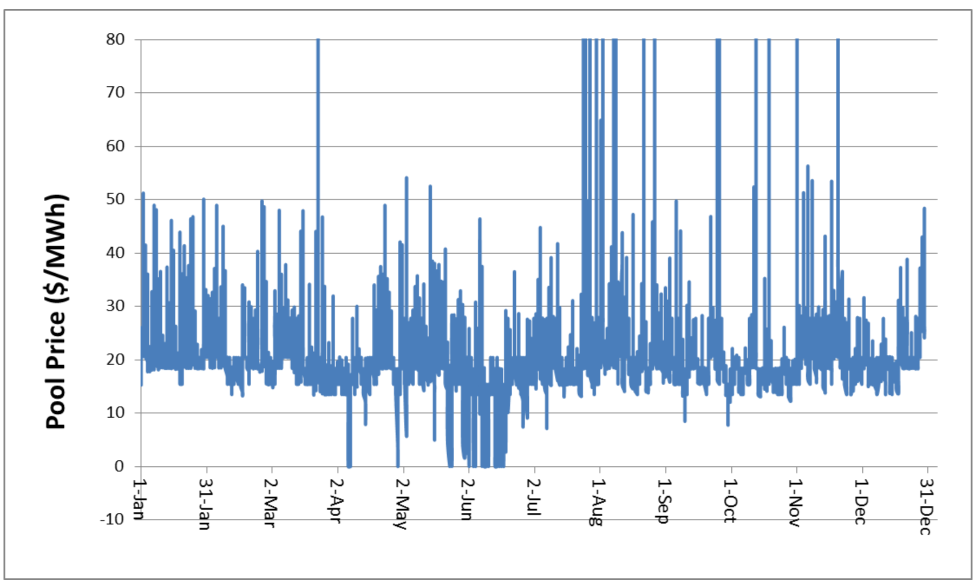

Figure 44: Historical Hourly Pool Prices for AESO (January 1st to December 31st, 2017)

Source: (ETS AESO, 2017)

In this study prices varied between water years, in general the prices were highest in dry conditions and lowest in wet conditions. Future prices are subject to change given the mechanism that drives them in regulated markets, the merit order among other factors. More renewable energy in the US and Alberta could affect the magnitude and shape of the price. The ancillary services prices were taken as average values from 2017 from the CAISO Open Access Same-time Information System (OASIS) as shown in Table 14. It was decided that using a time series of prices would require understanding the interplay between ancillary service prices and energy prices, which would go beyond the scope of this thesis. Although using average value might not be completely representative, a time series created by using extensive research could be equally as unrepresentative.

Table 14: Ancillary Service Prices from 2017 in CAISO

Parameter	Price ($/MW)
Regulation Up Price	9
Regulation Down Price	5
Spinning Price	7

4.3.4 Other Optimized Plants

This section will briefly describe the other hydroelectric plants that were optimized during this study. These plants were the Mica Generating Station, Revelstoke Generating Station, Arrow Lakes Generating Station, G.M. Shrum Generating Station, Peace Canyon Generating Station, and Site C. All of these are either constructed or are planned plants and are owned and operated by BC Hydro.

Mica Generating Station

The Mica Dam was one of the three Canadian projects constructed and operated in accordance with the terms contained in the Columbia River Treaty. It became operational in 1973 and is located near Mica Creek approximately 145 km north of Revelstoke, BC. The dam is 240 m high and impounds a section of the Columbia River which is now named the Kinbasket Lake. The live storage in Kinbasket Lake is approximately 14.8 km^3 with an annual generation of about 7200 GWh. The large volume of water that can be stored in Kinbasket Lake allows for multi-year storage planning. After upgrades and the addition of two generators since the initial construction the installed capacity is 2746 MW with 6 units.

Revelstoke Generating Station

The Revelstoke Dam is located north of the town of Revelstoke and downstream of the Mica Dam, also on the Columbia River. The powerhouse was built in 1984 and the current installed capacity is 2480 MW with 5 units and another unit planned. The dam is 175 m high and the reservoir is named Lake Revelstoke. The storage in Lake Revelstoke is 1.5 km^3, significantly less than that of Kinbasket Lake with an annual generation of about 7800 GWh. The plant is often operated as a run-of-river project during the freshet due to high natural inflows.

Arrow Lakes Generating Station

The Hugh Keenleyside Dam is located north of Castlegar and south of Revelstoke at the outflow of Arrow Lakes. The dam construction was completed in 1968 and was built as a part of fulfilling flood control obligations under the Columbia River Treaty. Similar to the Revelstoke and Mica Dams' it also impounds sections of the Columbia River. The dam is 52 m high and the reservoir, Arrow Lakes, contains approximately 8.8 km^3 of water with an annual generation of about 770 GWh. The installed capacity is 185 MW with 2 units, and the powerhouse completed in 2002 and is owned by the Columbia Power Corporation.

G.M. Shrum Generating Station

The W.A.C. Bennett Dam is located west of Hudson's Hope, BC on the Peace River. Construction was completed in 1968 and the current installed capacity of the powerhouse is 2730 MW with 10 units. The dam is 162 m high and the reservoir, Williston Lake, contains approximately 74.0 km^3 of water with an annual generation of about 13300 GWh. It is one of the largest artificial lakes in North America. The large size of this reservoir allows for multi-year storage planning.

Peace Canyon Generating Station

The Peace Canyon Dam is located 23 km downstream of the W.A.C. Bennett Dam on the Peace River west of Hudson's Hope. It first came into service in 1980 and the current installed capacity of the powerhouse is 694 MW with 4 units. The dam is 50 m high and the reservoir, Dinosaur Lake, contains approximately 0.2 km^3 of water with an annual generation of about 3500 GWh. The operation of this plant is mostly as a run-of-river project as it is controlled by the releases from the G.M. Shrum Generating Station.

Site C

The Site C Clean Energy Project will be the third dam and hydroelectric project on the Peace River. It will be located downstream of the W.A.C. Bennet Dam and Peace Canyon Dam near Fort St. John, BC. The expected completion date for construction is 2024 with a capacity of 1100 MW with 6 units. The dam is planned to be 60 m high and the reservoir will contain approximately 2.3 km^3 of water with an annual generation of about 5500 GWh.

Chapter 5: Results

This chapter examines the results in the following three ways. The effects of adding PHS to the system are explored. Next, the variability of benefits between the projects are compared in terms of absolute value, weighted by capacity and weighted by storage. Finally the results regarding the value of these projects are discussed.

5.1 System Study

The first step in validating the results of the optimization model is to make sure that the operation of the PHS plant is behaving as expected. Figure 45 and Figure 46 both show a time series of the flow from PSP1 (1500 MW 30 000 MWh) versus the forebay of the upper and lower reservoir, respectively. These figures shows that when PSP1 is generating power there is a corresponding decrease in the upper reservoir forebay and increase in the lower reservoir forebay. The changing forebay in the reservoirs is happening coincidently as shown in Figure 47. This test is a proxy for whether or not water is actually being moved between reservoirs.

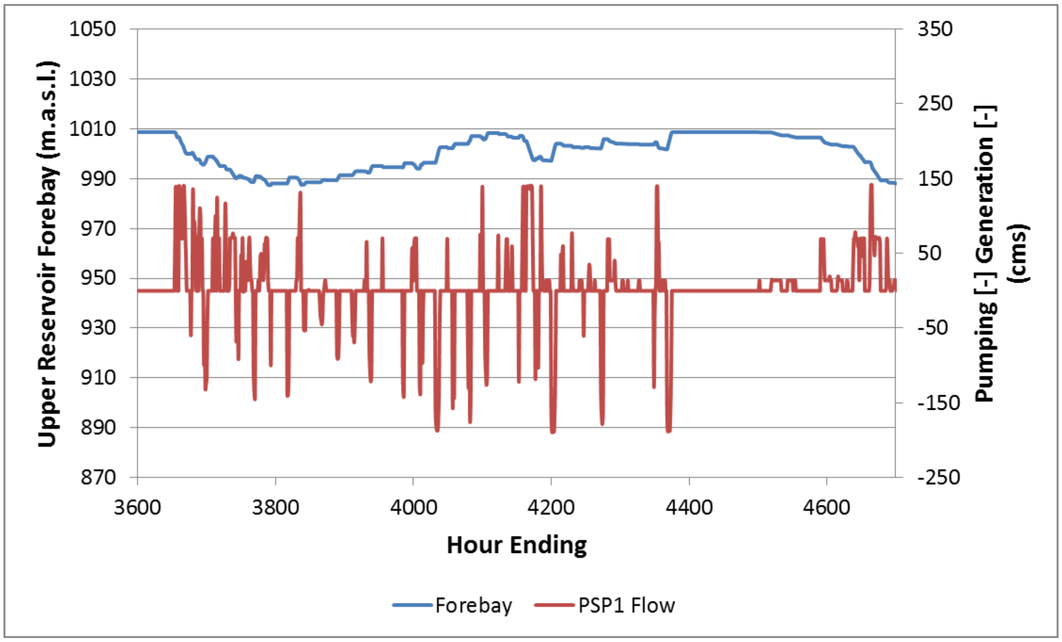

Figure 45: Upper Reservoir Forebay vs. Flow (1500 MW 30 000 MWh, 1967)

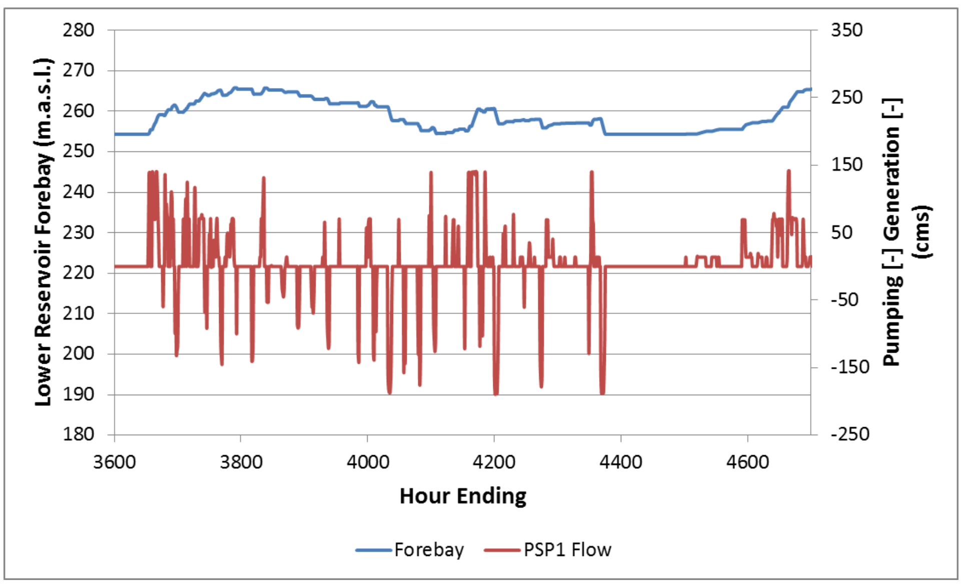

Figure 46: Lower Reservoir Forebay vs. Flow (1500 MW 30 000 MWh, 1967)

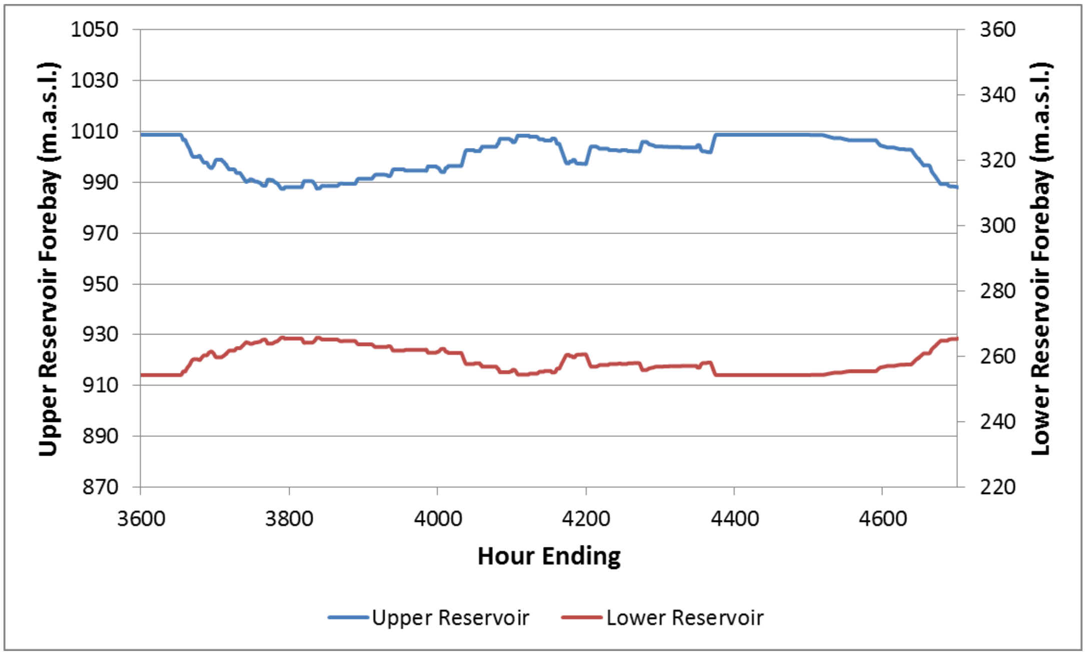

Figure 47: Reservoir Forebay Example (1500 MW 30 000 MWh, 1967)

In addition to water physically moving between reservoirs, it is important these flows are limited by physical constraints and that these limits are changing with respect to the forebay. Figure 48 shows a time series of the turbine and pump flow limits. These limits are plotted on different axis because the magnitude of the change in each limit is relatively small compared to the difference between the limits themselves. In this time series the maximum turbine flows (shown in red) vary by approximately 10 cms whereas the difference between the turbine and pump flows (red vs. green) vary by approximately 455 cms. This figure shows that the limits are changing, and if compared to Figure 45, are changing proportionally to changes in the forebay. Comparing timestep 3600 to timestep 3800, as the upper forebay decreases there is a corresponding increase in turbine flow to generate the same amount of power. Similarly, more water can be pumped with the same amount of power as the upper forebay decreases. Figure 49 is a time series of PSP1's flow with the limits showing that the flow is not exceeding the limits.

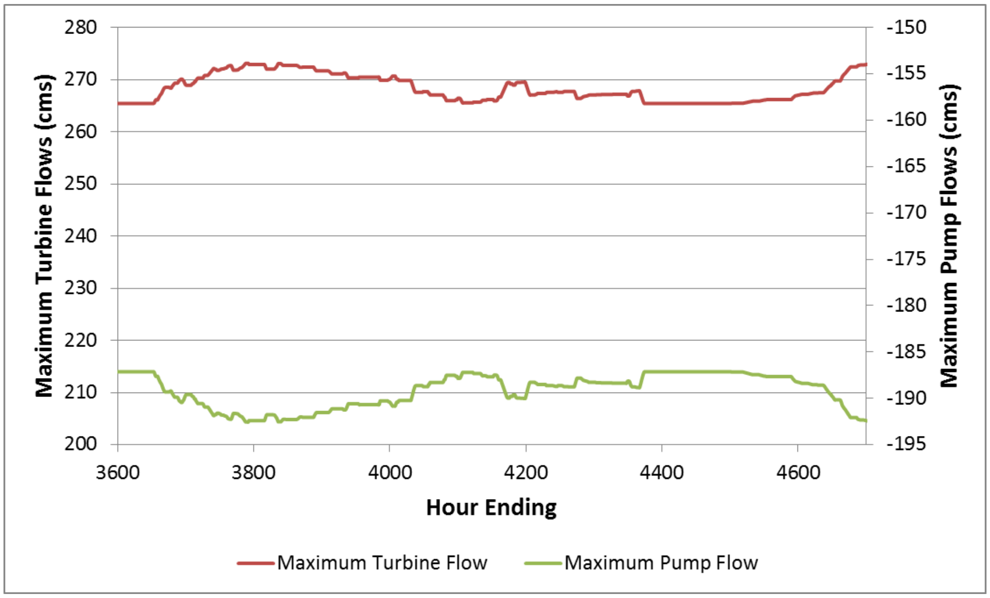

Figure 48: Flow Limits (1500 MW 30 000 MWh, 1967)

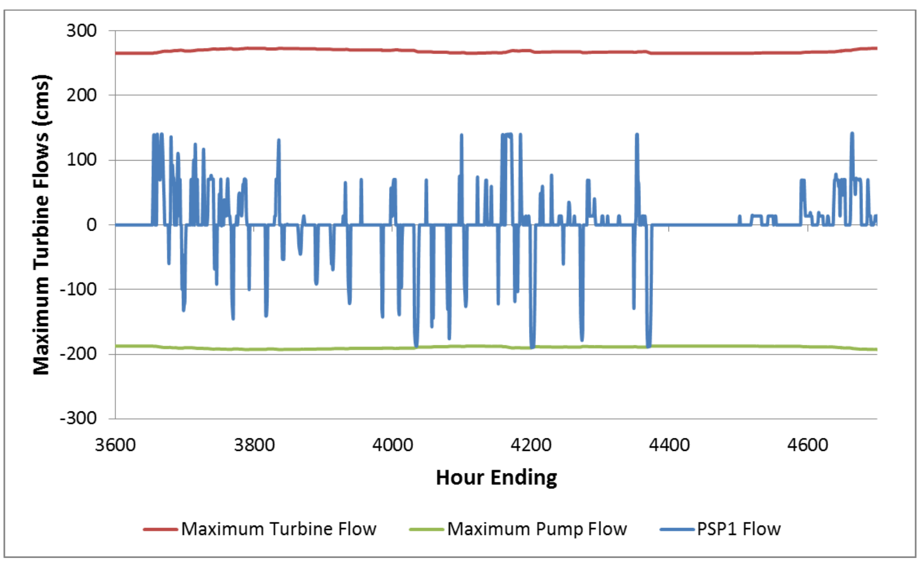

Figure 49: Flow and Flow Limits (1500 MW 30 000 MWh, 1967)

As discussed in Chapter 2, PHS or any energy storage system, is a net energy user. This means that for the PHS system the cumulative energy generated should be less than the energy pumped over the entire year. Figure 50 shows the cumulative energy use for the 500 MW 5000 MWh project across the different years, confirming what was expected. This figure shows that the use of the PHS system is not uniform across different water year conditions. For this project it is used the most in 1971, which is an extremely wet year where the entire system is in surplus, and this behavior makes sense as the PHS system tries to pump as much as possible during this year to reallocate the excess energy.

Figure 51 shows the average cumulative energy use across all of the years studied for all of closed loop projects. In general, this figure shows an increase in overall use with increasing capacity and storage. The fact that the use does not flat out as the capacity increases indicates that, across the range of project sizes studied, there is no maximum amount of usefulness of PHS. Across the same installed capacity, an increase in storage results in an increase in use. Interestingly, comparing the 100 MW 1000 MWh project with the 500 MW 1000 MWh project shows that a higher capacity with the same amount of storage results in significantly more use. Comparing the 500 MW 5000 MWh project with the 1500 MW 3000 MWh project shows that there can be an increase in capacity and a decrease in storage that results in an increase of use. The ratio of energy generated to energy pumped or roundtrip efficiency for each project is approximately 72% which is consistent with other studies found in Chapter 2. This ratio is associated with the turbine and pump characteristics used to create the input parameters as described in Chapter 4. This, however, does not include potential energy gains at the system level.

Therefore, it can be concluded that the model behaves as expected.

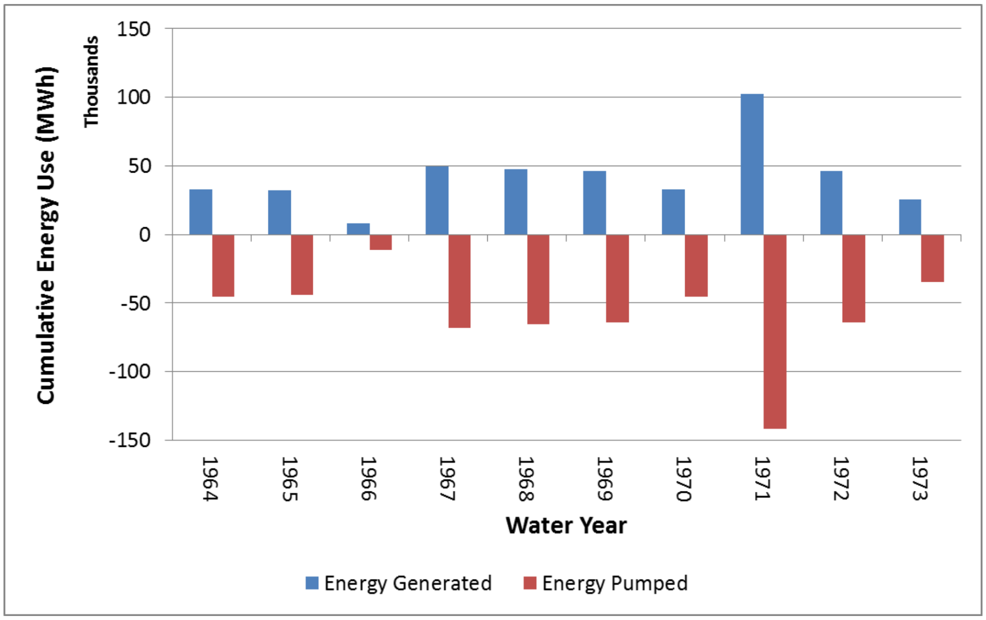

Figure 50: Energy Use for 500 MW 5000 MWh vs. Year

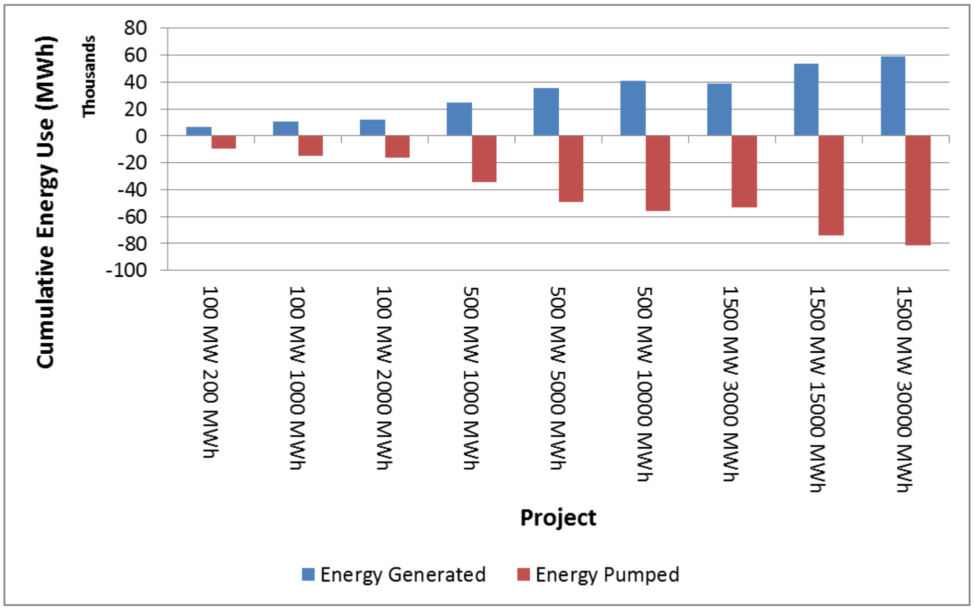

Figure 51: Average Energy Use Across Year By Project

5.2 Benefits Study

The next step is to examine the relative benefits of different projects and years. To reiterate, the yearly benefit calculated in this study is the incremental increase of the optimization model objective function from a base study to a study that includes PHS. This increase consists of an increased ability to capitalize on trade opportunities and use BC Hydro resources more efficiently. Due to the amount of confidential information contained in the study, the benefits were normalized according to the process outlined in Chapter 3. It is noted that a normalized benefit of zero should not lead to the conclusion that the project or year has no benefit. A normalized benefit of zero means that, in a specific comparison, that project or year has the least benefit of all compared projects or years. Similarly, a normalized benefit of one means it has the most benefit of all compared projects or years. This method of normalization has the limitation of visually exaggerating the difference between different values by normalizing each value by the largest difference between numbers in the set of results.

Figure 52 shows the benefits for each project organized by year of the study. Each color represents one of the projects: organized first by capacity and then by storage. This figure shows that the benefit for the Mica Extension project is much higher than for any of the closed loop projects. It also shows that the benefits are not highest for all projects in any year, this is a surprising result. For example, the year with the highest benefit for the Mica Extension project was 1971 whereas the year with the highest benefit for the closed loop projects is 1967. It was expected that the benefits from PHS would be highest in the most extreme wet (1971) and dry (1969) conditions. The benefits change according to the different capacity and storage of the project as expected. This supports the conclusion that across the range of projects studied there appears to be no upper limit of usefulness of PHS.

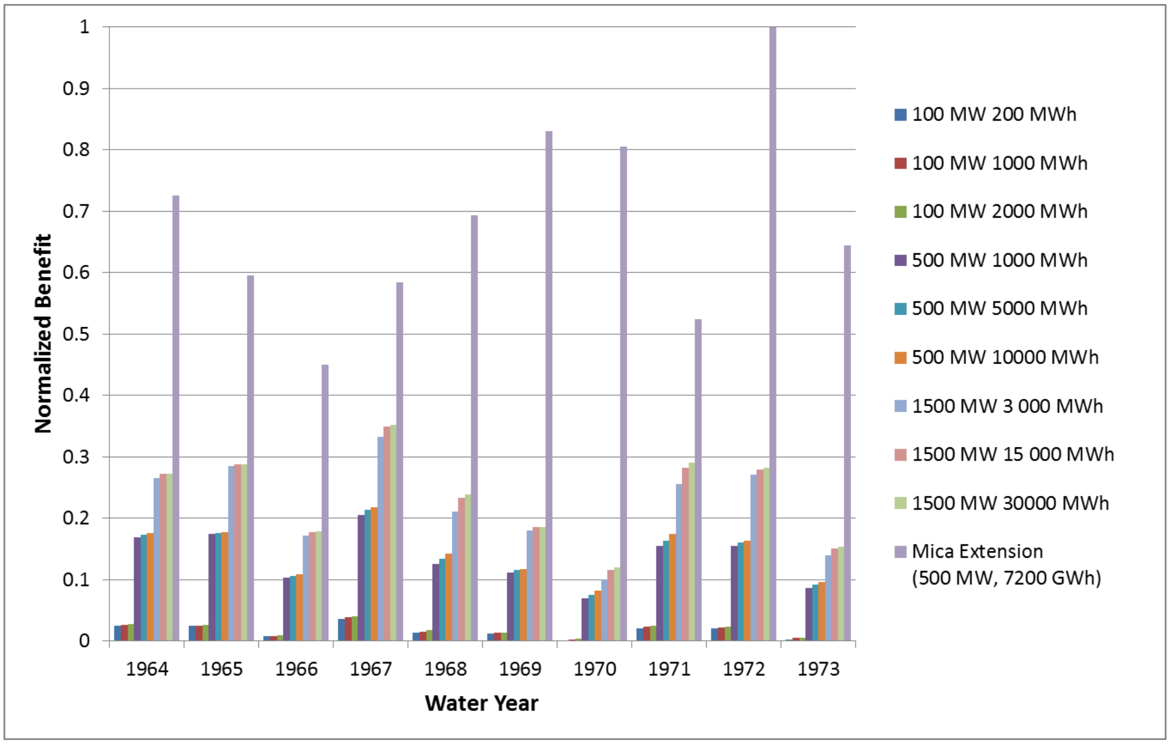

Figure 52: Normalized Benefits vs. Year

Figure 53 and Figure 54 shows the average benefit across the different years for all of the closed loop projects, and the Mica Extension project, respectively. As discussed earlier, a normalized benefit of zero should not lead to the conclusion that the year has no benefits; just that it has the least of the compared set. From these figures, the benefits are not uniform across different years and are different for closed loop projects compared to the Mica Extension project. Shown in Figure 53, the benefits for closed loop projects are highest in 1967, 1971, and 1972 and lowest in 1970, 1973 and 1966. Although 1967 and 1971 are relatively wet years, 1972 is fairly average and 1969 (dry) is not on the list of highest benefits, suggesting that extreme conditions aren't necessarily causing high benefits for closed loop projects. Shown in Figure 54, the benefits for the Mica Extension project are highest in 1972, 1969, and 1970 and lowest in 1966, 1971, and 1967. In this case the years with the highest benefit are dry years and those with the lowest benefit are wet years. These are observations and are not sufficient to make generalizations extending to projects beyond what has been done in this research.

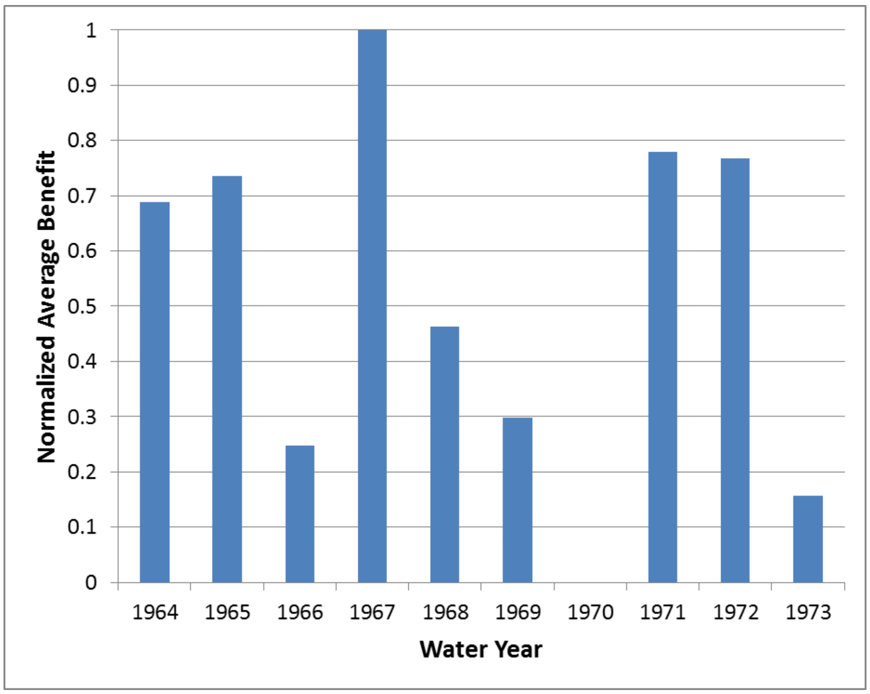

Figure 53: Normalized Average Benefit of Closed Loop Projects vs. Year

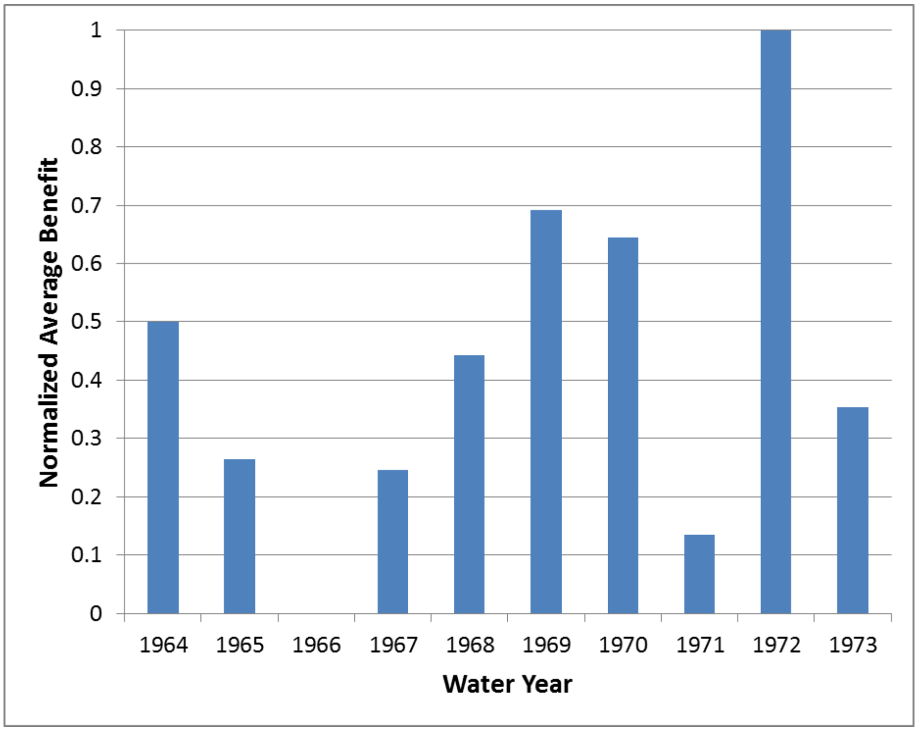

Figure 54: Normalized Benefit of Mica Extension vs. Year

Figure 55 shows the average benefits across all water years versus the capacity of the project: 100 MW (blue), 500 MW (red) and 1500 MW (green) for different energy storage capacities. In general, as the capacity increased the benefits also increased. Since there are so few data points across the capacity dimension it is not prudent to fit a function to predict the benefit based on the capacity, but the trend can be observed and is useful. Figure 56 shows the average benefits across all water years versus the storage of the project where the colors of the capacity of the project remain the same as in the previous figure. There are many more points across the storage dimension, however still not enough to confidently fit a function to predict the benefits of other projects. As the storage increases the benefits also increase, however there are potentially diminishing returns observed by the shape at higher levels of storage. This figure also shows that for the same amount of storage more benefits can be realized with a higher capacity when comparing the 100 MW 1000 MWh and 500 1000 MWh projects. From these figures, it is likely that the capacity has a larger role in determining the benefit of the project. This is likely due to the optimization modelling method where the value of the excess capacity that can be sold in the ancillary markets is higher than the value of selling the physical energy.

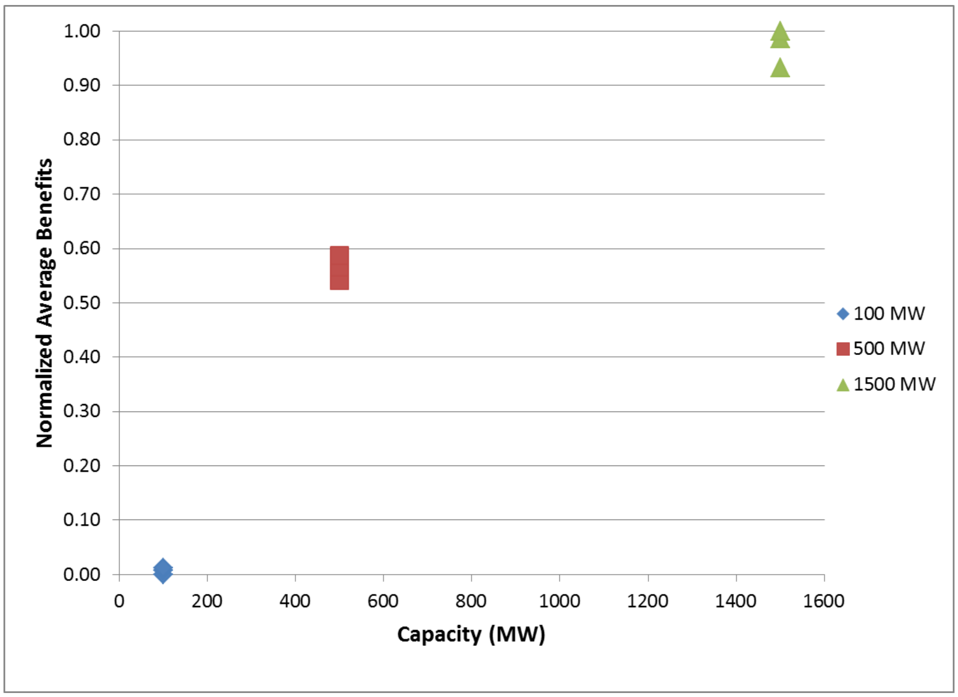

Figure 55: Normalized Average Benefits vs. Capacity (MW)

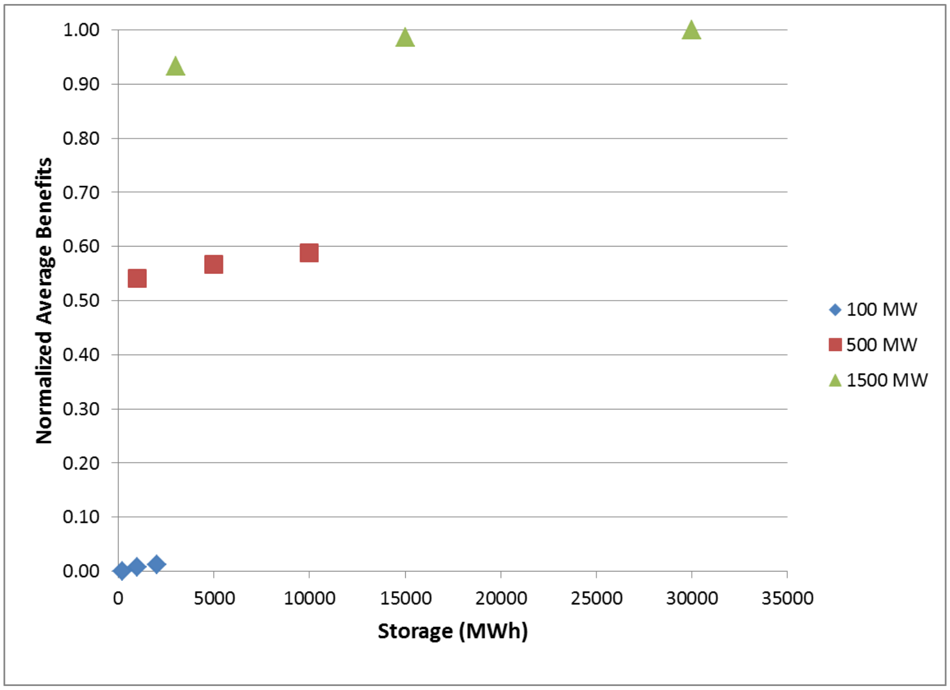

Figure 56: Normalized Average Benefits vs. Storage (MWh)

Figure 57 shows the benefit for each project averaged across all years in the study. In this figure the Mica Extension project is included to highlight that it's benefits are much (~2.5) higher than any of the closed loop projects. Since the capacity of the Mica Extension project (500 MW) is within the range of the other projects, this high benefit is likely a result of the amount of large amount of storage in Mica's reservoir. Although, from the above discussion and this figure it is clear that capacity plays a major role in the benefits. Figure 58 shows the same information as the previous figure weighted by the capacity of the project. From here it is clear that for closed loop projects the unit capacity benefit is highest for smaller capacity projects. Overall, the unit capacity benefit is highest for the Mica Extension project. Rather than weighting by capacity, Figure 59 shows the average benefits weighted by the storage. This figure shows that for each capacity, the benefits are highest for the smallest amount of storage or shortest duration. It also shows that when comparing the capacity by duration, the smaller capacity has a higher unit storage benefit.

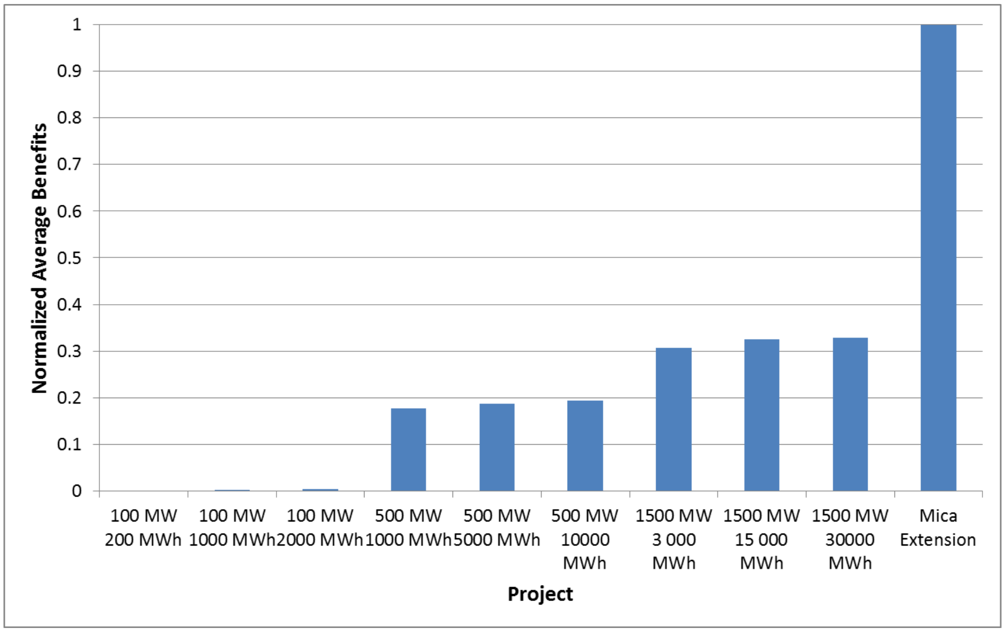

Figure 57: Normalized Average Benefit Across All Years by Project

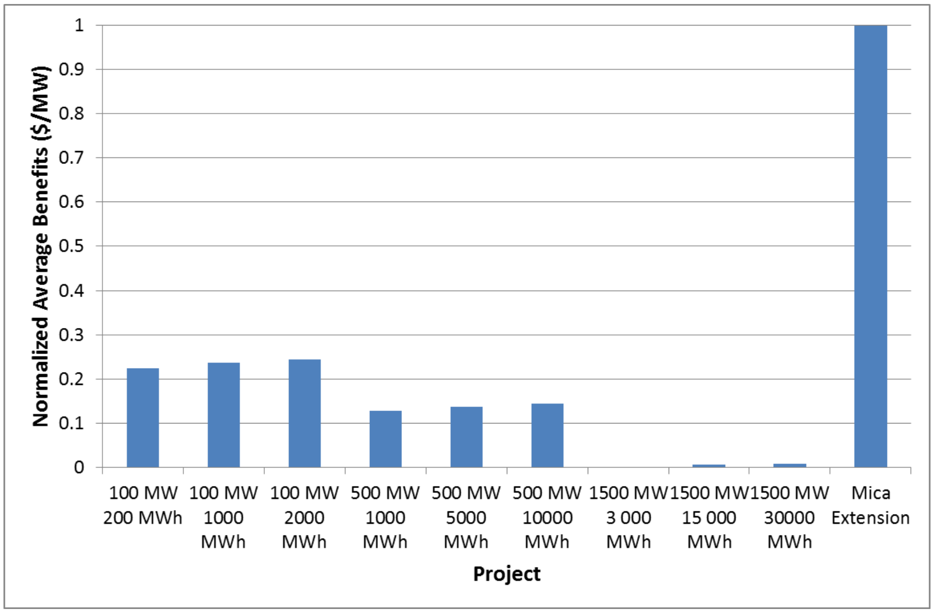

Figure 58: Normalized Average Benefit Across All Years by Project (Capacity Weighted)

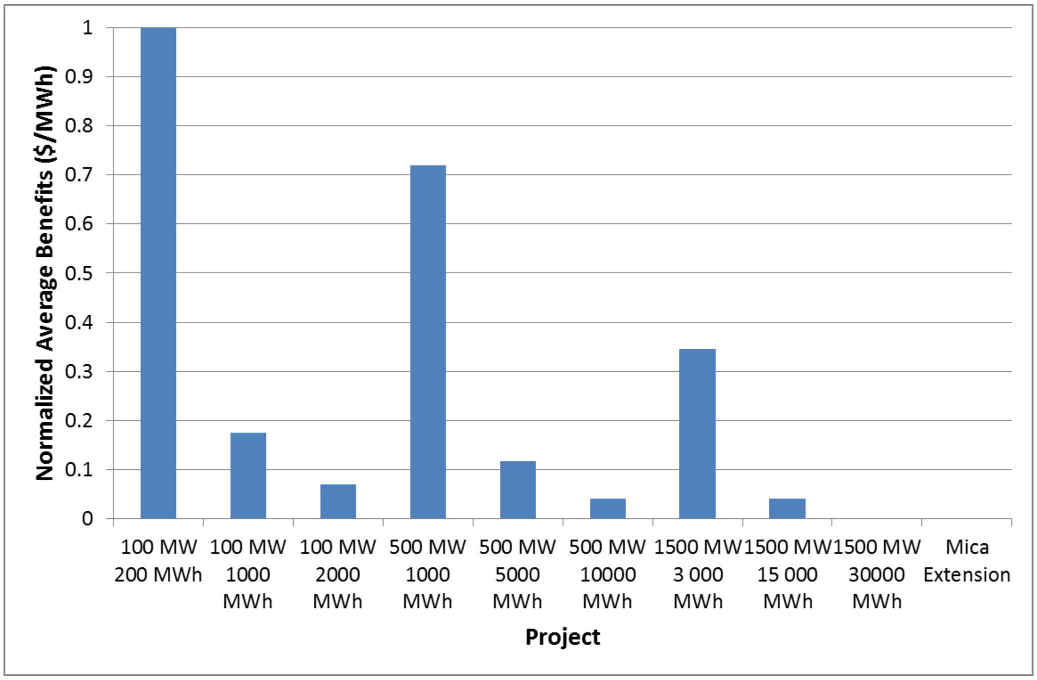

Figure 59: Normalized Average Benefit Across All Years by Project (Storage Weighted)

5.3 Cash Flow Study

The purpose of this section is to examine the benefits in the context of the costs of each project to reflect the value in terms of NPV. As shown in the previous section the benefits are generally higher for larger capacity or storage projects, however these projects are more expensive. The construction costs were incurred in year 0 of the project, and the other cash flows including operations cost and revenue were discounted back to this year. All of the economic inputs for this analysis can be found in the Chapter 3.

Figure 60 shows the normalized NPV organized by project. The project with the highest NPV is the 100 MW 200 MWh project and the project with the lowest NPV is the 1500 MW 30000 MWh project. A potential reason for this result, where the smallest project has the highest NPV and the largest with the lowest NPV, is the cost of the project. Lacking a better way of estimating scalable site specific costs, the unit energy cost was used. This means that a project with 30000 MWh of storage has a capital cost 150 times more than the project with 200 MWh. The net present value of the benefits and operations costs would have to be 150 times greater for the larger project in order for it to have a higher NPV. The NPV for the 500 MW 1000 MWh project is higher than that of the 100 MW 1000 MWh project, showing that there is more value for a higher capacity project. For the closed loop projects, the NPV is highest for the least amount of storage for each capacity. The NPV for the Mica Extension project is similar to projects in the 500 MW range. The benefits for this project, as shown in the previous section, are much higher than the closed loop projects. A more accurate estimate of the closed loop project cost, likely increased, would lead to a higher NPV of the Mica Extension relative to the 500 MW projects.

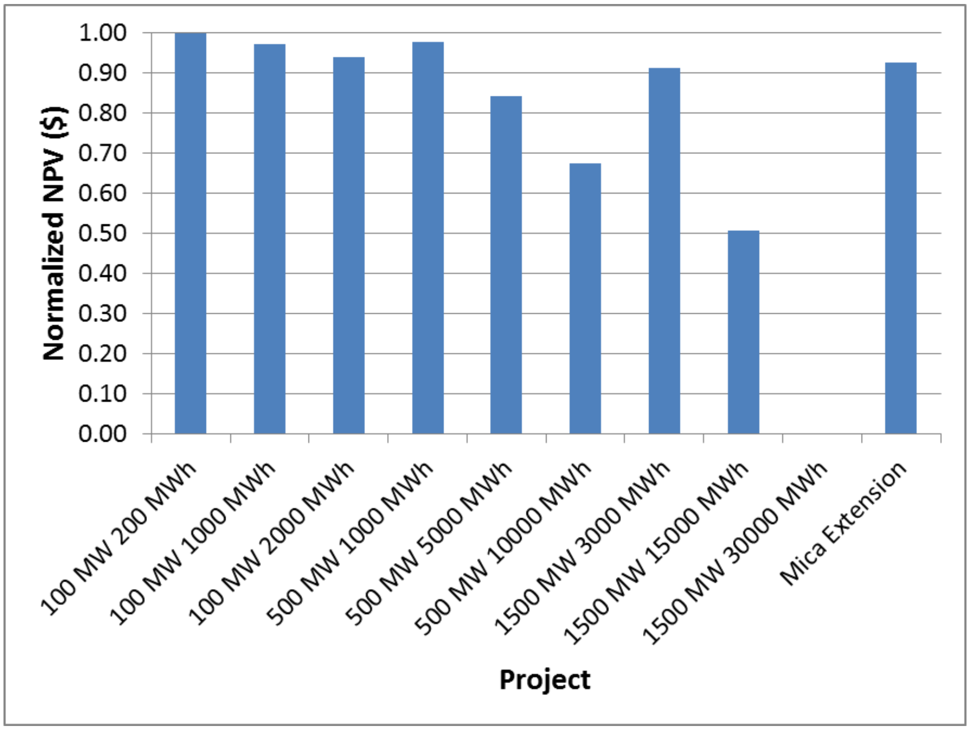

Figure 60: Normalized NPV by Project

Figure 61 and Figure 62 show the NPV weighted by the capacity and storage, respectively. Since the projects have the same lifetime and the results are normalized, the shape is the same as if they were further weighted by the duration of their lifetime. In this analysis, since the net benefits are not higher than the costs, these metrics are referred to as the cost of capacity and storage respectively. It means that the costs are not outweighed by the benefits obtained in this study, considering trade benefits and increased resource efficiency. There are other benefits that can be considered in future studies, which will be discussed in the next sections. In these figures a low value is good, decision makers should look for projects with low costs of capacity and storage. As expected, as the storage increases the cost of capacity increases due to the relative size of the costs to the benefits. The cost of storage for the Mica Extension project is extremely small because the amount of storage in Kinbasket Lake is very large (~7000 GWh) if considering discharging only with the pump turbines.

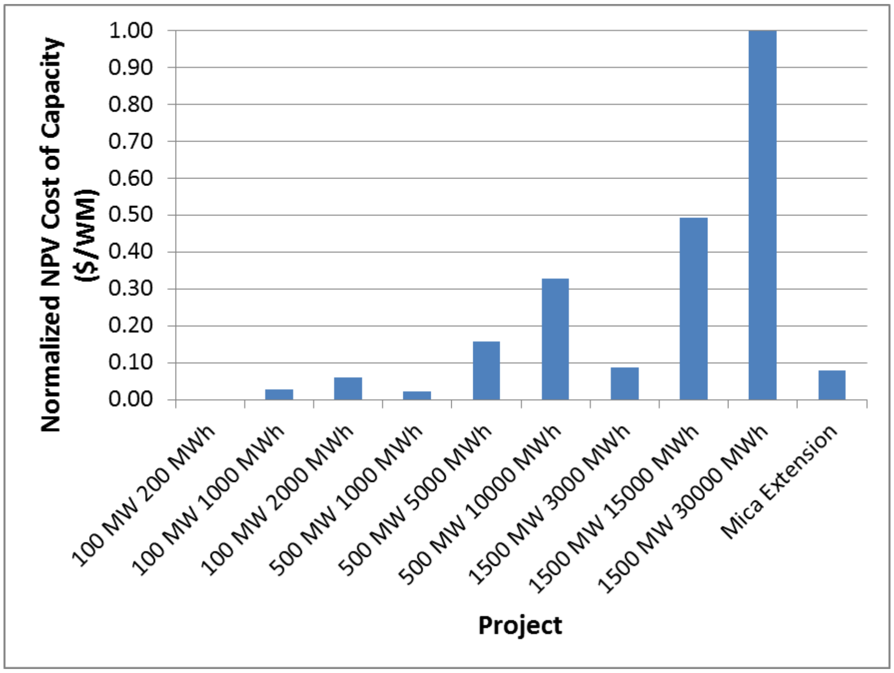

Figure 61: Normalized NPV Cost of Capacity by Project

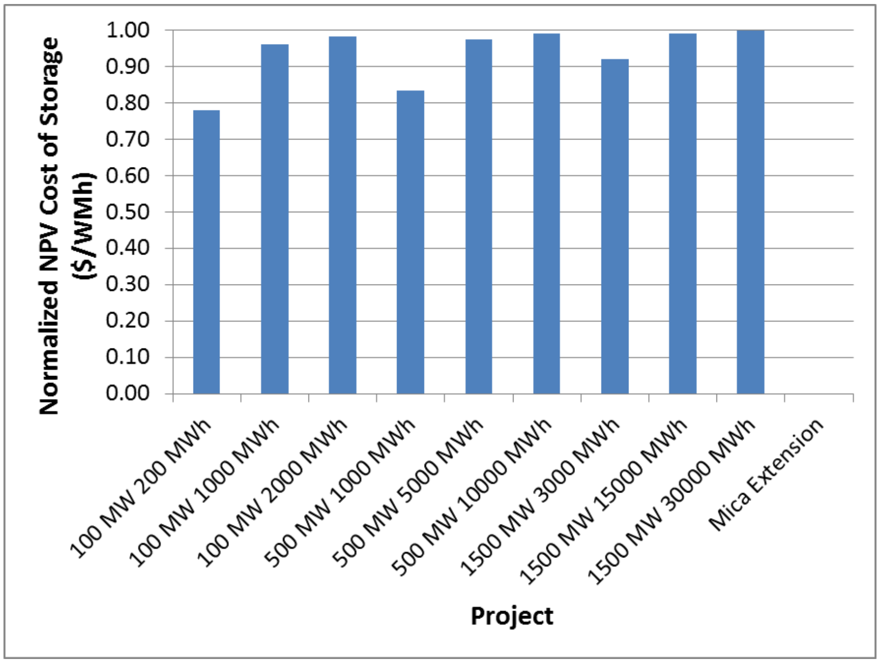

Figure 62: Normalized NPV Cost of Storage by Project

5.4 Sensitivity Analysis

The purpose of this section is to discuss the sensitivity of the NPV to the input parameters of the Cash Flow Analysis. The input parameters for each year were not studied since 10 years were used which provided a reasonable representation of the potential variance in parameters such as the inflows to reservoirs and the electricity market prices. The input parameters that were varied are: the capital cost, benefits, discount rate, inflation rate, and operations and maintenance cost. For each parameter a pessimistic and optimistic value was determined and the NPV recalculated. These parameters as well as their pessimistic and optimistic values as a percentage of the original case are shown in Table 15.

Table 15: Input Parameters for Sensitivity Analysis

Parameter	Pessimistic	Optimistic
Capital Cost	+40%	-40%
Benefits	Minimum	Maximum
Discount Rate	+17%	-17%
Inflation Rate	+18%	-59%
Operations and Maintenance Cost	+50%	-50%

Figure 63 shows the change in the NPV (%) as a function of the variation of the input parameters for one of the projects (500 MW 5000 MWh). There were 10 sensitivity cases studied for each project, with 10 projects, for a total of 110 cases including the base case. Although this sensitivity analysis was done for all of the projects, this figure is shown because it captures the relative magnitude of the change between parameters in all of the projects.

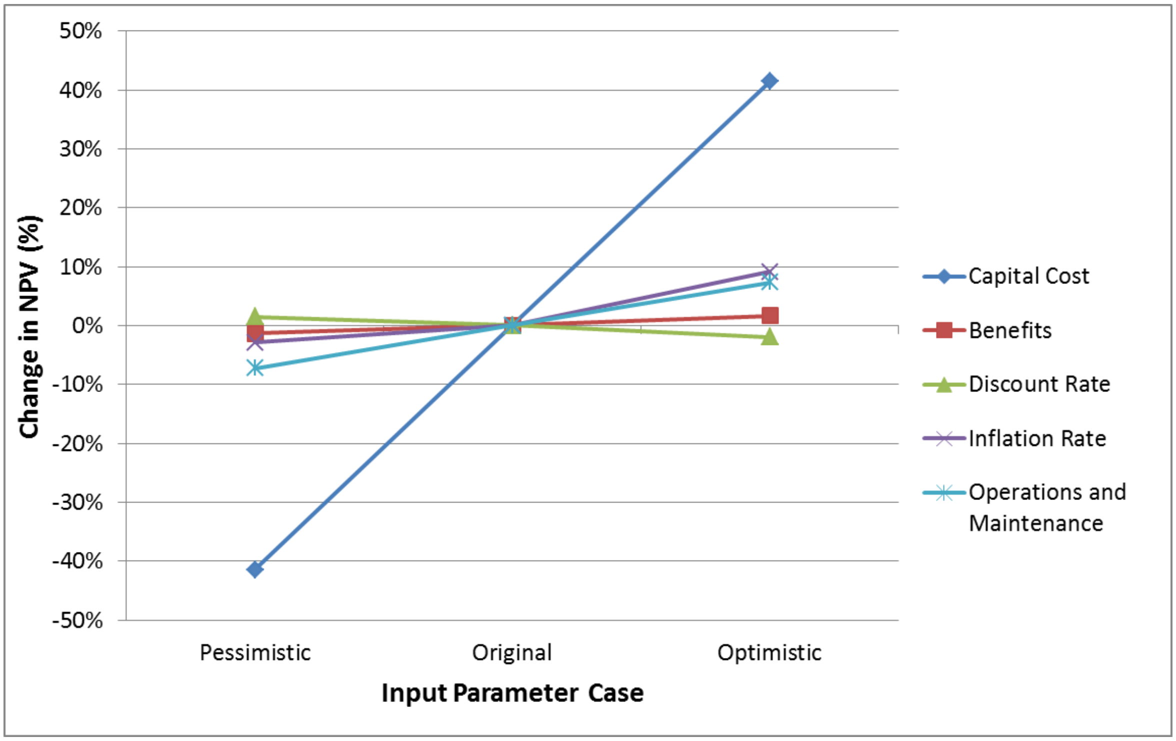

Figure 63: Sensitivity of NPV to Inputs (500 MW 5000 MWh)

The results of the sensitivity analysis for all other projects, as well as Figure 63, shows that the variation of capital costs considered in this study has the largest impact on NPV. Since the inflation rate has a direct impact on the capital cost of the project, it also had a large impact on the NPV. The variation of benefits, between their maximum and minimum value for the years studied, had the least impact on the NPV. The variation of benefits had a larger impact on higher storage projects for the same capacity. In general, as the storage increased the variation of benefits had less of an impact on the NPV. The discount rate had an unexpected effect on the NPV, as the pessimistic case brought the NPV up in some cases. This is caused by the relative magnitude of the operations and maintenance cost to the benefit in a these cases.

Chapter 6: Discussion

This chapter highlights the conclusions and suggests future work that can be done to extend this research. The relevant conclusions are drawn and summarized including limitations to the research. To conclude this thesis, opportunities for future work to extend the scope of this research is discussed.

6.1 Conclusions

This thesis presents a method of valuing PHS plants at a high level of planning by considering trade and system optimization benefits. The BC Hydro GOM model was modified to be able to optimize PHS plants integrated in the BC Hydro system. The benefits or revenues were considered as the increase in the objective function of the GOM model when including a PHS plant and were compared to a base case without a PHS plant. A case study was prepared including both closed loop plants and the extension of an existing hydropower plant. The closed loop plants had capacities of 100, 500 and 1500 MW. Each capacity had three storage capacities able to generate at full capacity for 2, 10 and 20 hours when the storage was full. The extension of an existing hydroplant was at the Mica Dam with a capacity of 500 MW. In total there were 10 cases including PHS and one base case. The model was run across a set of 10 years representing typical hydrologic conditions and their corresponding prices with possible configurations of the BC Hydro system. The NPV was considered by discounting estimated future cash flows across the project lifetime which included the capital cost, operations and maintenance cost, and revenues.

The model performed as expected and captured the expected behavior of a PHS plant. Water was moving between reservoirs and limits on variables were changing accordingly. Plants were used mostly in the year coincident with higher than normal inflows to reservoirs. As the capacity and storage of the closed loop plants increased, the usage also increased. Across the range of configurations of projects included in this study there was no maximum usefulness observed. The plants were able to generate approximately 72% of the electricity that was used for pumping.

Benefits were not uniform across the set of water years reflecting the characteristics of each year's conditions and configuration of the system. The benefits of the Mica Extension plant were much higher than any of the closed loop projects in all years. Increasing the capacity and storage both resulted in an increase in benefits. For closed loop projects the unit capacity benefit is highest for smaller capacity projects. The unit capacity benefit for all projects investigated is highest for the Mica Extension project. The benefits are highest for the smallest amount of storage or shortest duration. When comparing the capacity by duration, the smaller capacity has a higher unit storage benefit.

The project with the highest NPV is the 100 MW 200 MWh project and the project with the lowest NPV is the 1500 MW 30000 MWh project. The NPV for the 500 MW 1000 MWh project is higher than that of the 100 MW 1000 MWh project, showing that there is more value for a higher capacity project. For the closed loop projects, the NPV is highest for the least amount of storage for each capacity. The NPV for the Mica Extension project is similar to projects in the 500 MW range. As the storage increases, the cost of capacity increases due to the relative size of the costs to the benefits. The Mica Extension project has the lowest cost of storage.

The NPV of all projects was most sensitive to the variation of construction costs. This indicates that this is a very important parameter to carefully assess when considering a PHS project. The variation of the benefits within those realized in this study show that, from the cash flow analysis perspective, studying 10 years may not be necessary. However, considering all of the years may be important from an operational perspective.

To reflect, the goal of this thesis is to explore the value of the integration of a PHS plant into BC Hydro's system at a high level of planning. The objectives of this thesis were to accurately model PHS in BC Hydro's system, create a tool for valuation based on discounted cash flows, and look at tradeoffs between capacity and storage. The goals and objectives of this thesis were achieved, and it is emphasized that the methodology is more important than the exact value of the results. This methodology can be applied to projects with more certain estimates of characteristics and costs.

In conclusion, there is a benefit for including PHS into the BC Hydro system. The methodology proposed in this thesis can be used by BC Hydro to determine the value of potential PHS plants. The cost recovery of these plants by looking at revenues that include trade and increased resource efficiency is unlikely. BC Hydro, being a vertically integrated utility, is not required to justify the construction of a plant on the premise that it will pay for itself by trading in restructured markets. There are additional benefits, such as deferred transmission investment and value of system flexibility, that were not quantified within this thesis.

6.2 Future Work

There is a lot of potential future work to be completed in the field of energy storage, specifically determining the value of PHS in a hydropower dominated system such as BC Hydro. The work completed in this thesis is a stepping stone that can be used by future students and researchers to improve upon. This section consists partially of a reflection of sections of the study that can be improved, as well as an enthusiastic prediction of where the research will go in the future.

The first area of improvement is the base case study itself. There are advantages and disadvantages of using an existing study for this analysis. The major advantage is that, since there is so much data that goes into these studies, the researcher does not have to concern themselves with the statistical properties of the input data. Say a researcher wanted to only change the price to reflect new predictions; a time series generated by these new predictions might not contain accurate correlations with inflow sequences or other input parameters. Using historic data allows for the researcher to focus on the impact that PHS has on the system. The major disadvantage is that since an actual BC Hydro study was used for the base case, the system was already in load resource balance. Future work in this field could apply the same methodology used in this thesis with a study where the system was not in load resource balance and compare the benefits with other projects, such as gas turbines.

The next area of improvement is the methodology for determining the cost of PHS. The costs are site specific and it would be beneficial to examine a larger dataset of historic costs as well as projected costs to determine the cost of different configurations of projects at a given site. The cost estimate used in this research was very rough, and likely underestimated the cost of smaller projects and overestimated the cost of larger projects. Since the NPV was found to be the most sensitive to construction cost, future studies could consider fewer projects with more specific costs. Additional sources of benefits should be included in future studies of PHS projects. These should include environmental considerations such as greenhouse gas offsets as compared to gas turbines and valuation of the flexibility of the system. Deferring other investments in capacity and transmission assets should also be considered.

This method of modelling assumed perfect foresight of deterministic input parameters, one major area of improvement is to move towards stochastic optimization with a set of probabilistic input parameters and limited foresight. Rather than optimizing the operation over the course of an entire year at a time, modelling with limited foresight could run the model for a day or week at a time so that the PHS had no knowledge of future conditions when making a decision in the current period. Future studies in this field should also consider additional measures in the sensitivity analysis. This could include plant specific parameters such as varying the power input to output ratio, the roundtrip efficiency of the plant or even different configurations in terms of capacity and storage. The qualitative and quantitative environmental impacts of PHS should be also considered.

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