CLIMATE CHANGE IMPACTS ON RESERVOIR OPERATIONS IN THE COLUMBIA RIVER BASIN

By

MATTHEW MORROW MCDONALD

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To the Faculty of Washington State University:

The members of the Committee appointed to examine the thesis of MATTHEW MORROW MCDONALD find it satisfactory and recommend that it be accepted.

Michael E. Barber, Ph.D., P.E., Chair

Jennifer C. Adam, Ph.D.

Marc W. Beutel, Ph.D., P.E.

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CLIMATE CHANGE IMPACTS ON RESERVOIR OPERATIONS IN THE COLUMBIA RIVER BASIN

Abstract

by Matthew Morrow McDonald, M.S.
Washington State University
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Chair: Michael E. Barber

Research conducted in this study explores the implications of climate change on reservoir operations and management in the Columbia River basin. With around 70% of the Pacific Northwest's power supplied by hydroelectric facilities, consideration of the potential impacts on this supply due to a changing climate is crucial. In addition, climate change can alter flood storage capability and refill of reservoirs. Much of the hydropower generation and flood control in the region results from provisions outlined in the Columbia River Treaty between the United States and Canada. Changes to the treaty could take effect as early as 2024 with notice given by 2014, so reservoir managers are currently examining possible changes in operations under a new treaty. For this analysis, Libby Dam in the state of Montana was used as a case study to determine how flood storage, power generation, and other operational objectives could be impacted by changes in future climate. A simulation model of the dam was constructed using HEC-ResSim from the U.S. Army Corps of Engineers and used to examine potential changes in the dam's operational objectives. Streamflows resulting from a set of climate scenarios for the 2020s and 2040s were used to drive the model and test the sensitivity of different objectives to climate change.

Results indicated changes in the ability to meet operational objectives are imminent. In general, shifts in streamflow often resulted in exceeding reservoir target elevations during spring. The potential for hydropower generation significantly increased throughout spring and decreased throughout summer. Overall, the 2020s scenarios resulted in a 3% increase in average generation during winter months and a 7% decrease during summer months. On a yearly basis, generation increased by an average of nearly 8%. By the 2040s, a 5% increase in average generation during winter months and a 14% decrease during summer months was seen, with an average yearly increase of approximately 9%. Due to uncertainty in future climate and its impact on water timing and availability, this work has shown that impacts on reservoir operations are foreseeable. Flexibility in reservoir operations will ultimately be required to adapt to such effects.

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List of Abbreviations

BC Hydro	British Columbia Hydro and Power Authority
BiOp	Biological Opinion
BPA	Bonneville Power Administration
C	Central Change climate change scenario
cfs	cubic feet per second
CIG	Climate Impacts Group, University of Washington
COLSIM	Columbia River Simulation
CRB	Columbia River Basin
CRT	Columbia River Treaty
ECC	Energy Content Curve
FCC	Flood Control Curve
ft	feet
GCM	General Circulation Model
GHG	Greenhouse Gas
HD	Hybrid-Delta
HEC	Hydrologic Engineering Center
HYDSIM	Hydrologic Simulation model
IJC	International Joint Commission
IPCC	Intergovernmental Panel on Climate Change
kaf	thousand acre-feet
kcfs	thousand cubic feet per second

LW-D	Less Warming and Drier climate change scenario
LW-W	Less Warming and Wetter climate change scenario
Maf	million acre-feet
MC	Minor Change climate change scenario
MW	Megawatt
MW-D	More Warming and Drier climate change scenario
MW-W	More Warming and Wetter climate change scenario
NOAA	National Oceanic and Atmospheric Administration
NWPCC	Northwest Power and Conservation Council
ORC	Operating Rule Curve
RMJOC	River Management Joint Operating Committee
SRD	Storage Reservation Diagram
SWE	Snow Water Equivalent
USACE	United States Army Corps of Engineers
USBR	United States Bureau of Reclamation
USFWS	United States Fish and Wildlife Service
VARQ FC	Variable Discharge Flood Control, Libby flood control procedure
VIC	Variable Infiltration Capacity

Chapter 1: Introduction

1.1 Management of Water Resources under Climate Variability and Change

Water management systems around the world have historically been designed and operated under the assumption of stationarity, the principle that hydrologic variability is defined by, and fluctuates within an unchanging envelope of likely runoff scenarios (Milly et al. 2008). The growing recognition that this fundamental assumption is false means that new reservoir operation and associated water management strategies are critically needed to mitigate against the worst-case climate change impacts on humans and ecosystems (Craig 2010; Lins and Cohn 2011). Complicating these efforts are conflicting and growing demands for water across multiple jurisdictions as well as often divergent laws, policies, and objectives (Hamlet 2011; Stefano et al. 2012). Robust and flexible strategies are required as cautious considerations of the long-term implications as changes are converted into policies. Pielke (2009) argues that these robust decisions must recognize the limits of what can be known instead of focusing on optimal decisions guided by prediction.

Contributing to the stationarity fallacy is global climate change (Milly et al. 2008). Global variability in climate naturally occurs over time, but anthropogenic factors over the last 250 years have increased and intensified greenhouse gases in the atmosphere. As a result of these forcings, global mean surface temperature is expected to increase by anywhere from 1.8–4.0°C (3.2–7.2°F) by the 2090s depending on future greenhouse gas emissions (IPCC 2007). In snowmelt dominated watersheds these changes can significantly alter the quantity and the temporal distribution of water thus placing greater challenges on existing infrastructure. Work has shown the Columbia River basin (CRB) in the Pacific Northwest United States is no exception to changes in future climate and direct impacts to water resource availability are likely (Miles et al. 2000; Payne et al. 2004; Mote and Salathe 2010). In general, mountain snowpack is expected to melt sooner in spring, decreasing already low summer flows and thus altering water resource availability. For example, a recent study conducted by researchers at Washington State University and the University of Washington predicted that climate change could alter the supplies and demands of surface water in the CRB (WSU 2012). The results indicated that while overall supplies are increased by around 3.0 (±1.2)% by the 2030s as compared to 1977–2006, the change is due to higher winter rainfall and runoff events thus decreasing summer base flow conditions and increasing demands at critical low-flow times in late summer and early fall (WSU 2012). Making the impacts of shifts in water timing and magnitude worse is an expected change in electricity demand due to warmer average temperatures (NWPCC 2010). Decreased summer flow means that hydropower generation could be hindered at times of increased electricity demand for air conditioning. Conversely, while winter rainfall and runoff events are expected to increase thus increasing the potential for hydropower generation, demand for electricity is expected to decrease because of a reduced need for heating.

1.2 Water Use in the Columbia River Basin

Water management within the CRB is the embodiment of a multi-jurisdictional watershed having essential and often conflicting socio-economic demands for a finite water supply. Groundwater is pumped to the surface and used for agricultural, municipal, and industrial purposes. Surface water in the basin is also used for these purposes, as well as hydropower generation, fisheries, recreation, navigation, and to meet water quality requirements. With multiple water use objectives in the basin, understandably there are multiple water resource managers. Federal, regional, state, and tribal entities all have a role, but most significant are the federal agencies due to the impacts of the Endangered Species Act and the preponderance of large federal hydropower and flood control projects. Agencies include the U.S. Army Corps of Engineers (Corps), Bonneville Power Administration (BPA), Bureau of Reclamation (USBR), and the National Marine Fisheries Service (NMFS) of the National Oceanic and Atmospheric Administration (NOAA). The Corps is responsible primarily for flood control and navigation, while BPA markets the hydroelectric power generated at the 31 federal dams in the basin. USBR is responsible for the operation of dams and waterways that provide water mostly for irrigation and NMFS has the role of protecting and restoring habitat in the basin.

The multiple water uses all depend on the timing and volume of available water, thus climate change could potentially affect the way the system is operated to meet these objectives (Hamlet and Lettenmaier 1999). Cohen et al. (2000) and Palmer et al. (2008) suggest that climate change will have more of an impact on basins dominated by dams; the CRB certainly falls into this category with over 250 reservoirs and approximately 150 hydroelectric facilities (NOAA 2012). Because of the dependence the Pacific Northwest has on hydroelectric facilities to supply up to 70% of its energy and the heavy reliance these facilities have on water availability, any changes in future climate could impact how reservoirs must be operated to meet power objectives. Another critical role of certain reservoirs in the CRB is flood control (BPA et al. 2001). Reservoirs have the ability to reshape the streamflow of river systems and decrease peak flows in spring, holding the water until it is needed. Uncertainties associated with climate change and the relative sensitivity of these objectives to altered future climate remains an area of focus for water planning agencies.

Exacerbating the potential climate change impacts on these objectives is the fact that water must often be shared across political boundaries, and for the CRB, this is one of the paramount issues when facing changes in climate (Hamlet 2011). The foremost water use agreement in the basin is the Columbia River Treaty (CRT) between the U.S. and Canada. The treaty was ratified in 1964 and governs flood control and hydropower operations on the river. The entities responsible for administering the treaty for the U.S. are the Corps and BPA, while British Columbia Hydro and Power Authority (BC Hydro) represents the Canadian interest. Under the treaty provisions, water is stored in Canadian reservoirs (Mica, Arrow, and Duncan) to protect against flooding primarily downstream in the U.S. and to facilitate optimal hydropower generation in each country. In return, the U.S. paid Canada a lump sum for the estimated future flood damages prevented and also provides Canada with one half of the estimated downstream power benefits on a continuing basis. The treaty also authorized the U.S. to construct Libby Dam on the Kootenai River ("Kootenay" in Canada) in the state of Montana mostly for flood control purposes. Either country has the right to terminate most treaty provisions in 2024, provided 10 years' written notice is given (USACE and BPA 2009). Possibly the most significant change that will occur regardless of treaty status is the switch to "called-upon" flood storage. Under called-upon storage, the U.S. must request that storage be made available in Canadian reservoirs. Storage would come at a price if needed, and would require the U.S. to make "effective use" of its own storage reservoirs prior to requesting additional reservoir space from Canada. The Corps has identified 8 reservoirs that could be utilized for the effective use requirement, including the two largest storage reservoirs: Grand Coulee Dam on the Columbia River and Libby Dam on the Kootenai River (USACE and BPA 2013). What called-upon storage specifically entails remains to be determined (USACE et al. 2010a), but would likely require the U.S. to make operational changes in the future to maintain system flood control.

Due to the substantial dependence the U.S. and Canada have on the CRT to ensure reliable flood control and hydropower, any potential changes in the hydrology of the system could have profound effects. Increased severity of droughts or higher magnitude peak streamflows due to climate change could represent such changes. Despite uncertainties in future climate, transboundary agreements can present the opportunity to enable water sharing mutually beneficial to both parties (Hamlet 2003). Though historically not the focal point of long-term planning studies, climate change is starting to be recognized by basin-scale water planning agencies as an important consideration when discussing future agreements (Osborn 2012). Water managers at the highest level have clearly acknowledged such importance in their more recent studies (Vaddey 2010; USACE et al. 2010b; USACE and BPA 2011), but uncertainties associated with climate change remain a concern.

Uncertainties are often addressed by reservoir operators and planners using computer models to aid in their decision making processes, thus multiple modeling tools have been developed over the years for this purpose (Yeh 1985; Wurbs 1993; Labadie 2004; Wurbs 2012). Models range from generalized reservoir system simulators to highly complex optimizers, with some having both capabilities. Generalized models can be applied to any basin or reservoir system, while others are built for a specific system and might not be easily applied to others. Very few existing models are considered both generalized and "user-oriented" (Wurbs 2012). User-oriented implies the model was designed for professional use and that it has been extensively tested and documented. Planners and operators use the models to examine various operating alternatives and/or to prescribe the most optimal operating alternative to meet their objectives both in real-time and for future operations. Optimization often requires the user to make many assumptions to find the "best" solution with the given constraints. Sensitivity analysis and testing multiple scenarios with various operational conditions can generally be achieved using a simulation model. Besides physical and operational constraints for a facility or the entire system, measurements or predictions of streamflow are usually the essential driving factor in these models. Labadie (2004) and Wurbs (2012) cite many of the more recent simulation models in use today.

1.3 Scope

Because it spans the U.S. and Canada and has significant storage potential, one of the dams most likely impacted by the CRT is Libby Dam. Using Libby Dam and Lake Koocanusa as a specific case study, this research examines climate change impacts on the operation of reservoirs and the resulting implications for water resources issues and water-based agreements like the CRT. The study is intended to provide a better understanding of the sensitivities of certain operational objectives of the facility to climate change. Previously developed climate change scenarios for two future timeframes are incorporated into a reservoir simulation model to quantify changes in flood storage, potential hydropower generation, and other operational objectives. Future streamflows at Libby Dam are the key driver of the reservoir model. Results are used in part to address climate change implications for the future of the CRT as it pertains specifically to Libby.

The overarching goal of this work is to address how climate change could affect potential hydropower generation, flood control, and other local reservoir objectives at Libby Dam. This goal will be achieved by completing the following objectives:

1. Replicate the physical aspects and operational objectives of Libby Dam using a computer-based reservoir modeling tool,
2. Use the reservoir model driven by a set of climate scenarios to determine a range of changes in reservoir storage and potential hydropower generation and these objectives' sensitivity to changes in future streamflows,
3. Utilizing specific operational alternatives and the modeling tool, examine the sensitivity of the dam's ability to meet objectives, and
4. Explore implications of the results from environmental and social perspectives and provide recommendations for future work.

A single-reservoir model for Libby that is used to examine climate change impacts on multiple operational objectives (e.g. power generation and flood control at the local scale, flow augmentation, recreational use) is not currently available. The single-reservoir approach presents a methodology for examining all the operational objectives of the dam in detail. Multiple larger and even basin-wide simulation models for the CRB do exist (Hamlet and Lettenmaier 1999; USACE et al. 2010c), but are not as efficient for analysis at smaller temporal and spatial scales or as easily adaptable as a single-reservoir model. Furthermore, these tools are not readily available in the public domain, and thus highlight a potential disconnect between researchers and stakeholders. By using a modeling tool that is publically available, this approach is intended to help alleviate this issue. A single reservoir model can also be used as a means of comparison with results from other basin-scale simulators, or possibly a starting point in the construction of such a model in a more detailed manner. This work is unique in that it examines the potential climate change impacts on a single, highly influential reservoir in the CRB. With negotiations regarding the future of the CRT fast approaching, detail at the single-reservoir level will ultimately be required to build a robust understanding of climate change impacts on the operation of the CRB reservoir system as whole, which this study aims to address.

1.4 Summary of Chapters

Chapter 2 provides background on previous studies that have focused on climate change and how it pertains specifically to the Pacific Northwest and Columbia River Basin. Methods for downscaling climate model output to the regional scale and how these models are chosen is briefly outlined. This is followed by a discussion of how climate change could affect reservoir operations and water-based agreements and some of the tools water agencies use in planning studies. The last section of the chapter discusses current reservoir simulation tools. Chapter 3 provides a description of the reservoir model used in this study with explanations of how the model is operated to meet its objectives. This chapter also describes the climate change scenarios and operational alternatives used to address Objectives 2 and 3 described in Chapter 1.3. The fourth chapter presents the results of the reservoir modeling, showing changes in Libby's storage and hydropower generation under the climate change scenarios. Also discussed in this chapter are potential impacts on the ecosystem and Columbia River Treaty. Finally, Chapter 5 provides conclusions based on the results and recommendations for future work.

Chapter 2: Background

2.1 Climate Change Analysis

Global climate variability and change and implications to water resources have been debated and investigated extensively in the past (Lettenmaier et al. 1999; Vörösmarty et al. 2000; Milly et al. 2005). Developing robust management strategies that adapt to these expected changes is becoming a priority at the international level. Since 1988 the Intergovernmental Panel on Climate Change (IPCC) has been developing predictions of future anthropogenic greenhouse gas emissions and their impact on climate (IPCC 2007). Most recently, results of the Fourth Assessment Report (AR4) indicated that the average surface temperature of the earth continues to rise (IPCC 2007). Guiding these predictions are simulation models known as general circulation models (GCM), which mathematically represent the interaction between the earth's surface and atmosphere. Using these models with predictions of future greenhouse gas emissions, researchers have developed multiple projections of future global climate conditions.

The scale at which these changes in climate occur is crucial, and often the smaller scale impacts are overlooked (Wilbanks and Kates 1999). Many studies have focused on the large scale impacts of climate change, but regional assessment will become increasingly important for planning purposes (Mearns et al. 2009). Water managers generally plan their systems at a local or basin scale, so coarse resolution climate modeling may be of less importance for their purposes. In a survey conducted by Callahan et al. (1999) stakeholders showed interest in regional level climate change impacts, but three quarters of respondents were concerned by the relative uncertainty in the modeling process as well as the difficulty in incorporating the information into decision making. Hawkins and Sutton (2009), though, have presented methods for helping to reduce uncertainties in modeling at the regional scale. Many have suggested that more robust modeling at the regional and local levels be conducted and communicated to decision-makers as climate change science becomes integrated into policy.

Because GCMs capture climatological processes on a global scale, results can be more meaningful at regional scales by using a process known as downscaling. Downscaling describes the process of transforming any coarse spatial and temporal scale climate data to finer spatial and temporal scales (Hamlet et al. 2010a). Methods for downscaling include statistical and dynamical approaches, with the latter more computationally intensive. Hamlet et al. (2010a) outlined two commonly used statistical approaches as well as a third they developed that captured many of the benefits of the other two, known as the hybrid-delta (HD) method. Downscaling requires information about the relationship between large and small scale processes, which is generally assumed to remain stationary with time. Though the seasonality of temperature and precipitation changes have been captured via downscaling, the non-stationarity of climate remains a source of uncertainty (Solman and Nuñez 1999).

While some studies have given precedence to climate scenarios based in part on a model's ability to recreate the historic conditions of a certain area (Tebaldi et al. 2005; Brekke et al. 2008), others have suggested that such weighting of models does not capture the full range of climate predictions (Markoff and Cullen 2008; Brekke et al. 2009). Mote et al. (2011) provide 7 guidelines to use when constructing climate scenarios, one of which being to use results from as many models and emissions scenarios as possible creating an ensemble of outcomes. The source of such reasoning is uncertainty. Uncertainty is associated with each step of the process: the GCM, emissions scenario, downscaling, and bias correction (Chen et al. 2011). By using multiple GCMs, much of the uncertainty can be addressed, however; using multiple simulations of one model in an ensemble can inappropriately weight that particular model (Mote and Salathe 2010). Markoff and Cullen (2008), for example, utilized GCM output from 7 models and 6 different emissions scenarios over 3 future time periods in combination to produce 70 climate scenarios, of which only half were chosen for their analysis. Scenarios were chosen to ensure the warmest and driest, and coolest and wettest conditions would be captured. Hamlet et al. (2010a) took the top 20 GCMs Mote and Salathe (2010) selected based on each models' ability to simulate historic 20th century PNW climate and reduced them to the 10 best. The top 10 were based on three metrics: a global performance index, the smallest bias in temperature and precipitation, and the ability to simulate annual variability in temperature and precipitation. Hamlet et al. (2010a) suggest using as many climate scenarios as possible, but maintain that "it is impossible to make an unqualified selection of the 'best' climate models."

2.1.1 Climate Change and Reservoirs

Reservoirs have typically been designed using historic periods of streamflow records to size storage and related dam infrastructure features including spillways and hydroelectric turbine capacities. Understanding climate change will likely impact the quantity and the timing of water availability, many studies have focused specifically on reservoir operations and objectives because of their dependence on the timing and total runoff volume of water. Some of the objectives examined at the academic level have included flood control (Lee et al. 2009, 2011), hydropower (Markoff and Cullen 2008; Hamlet et al. 2010b) and water quality and fisheries recovery (Callahan et al. 1999). Primary water governing agencies in the Pacific Northwest like the Corps and BPA have also examined the issue as it pertains to these same objectives (USACE and BPA 2011).

One anticipated effect of climate change is an increase in flood frequency and magnitude (Knox 1993; Milly et al. 2002). In the CRB specifically, expansive development around reservoirs and within natural floodplains has made flood control and risk reduction a primary goal (BPA et al. 2001). Many studies have been conducted that examine this specific objective (Lee et al. 2009, 2011; USACE and BPA 2011). Lee et al. (2011), for example, discussed how optimization of flood control operations would result in releases too high for maintaining elevation requirements downstream of Libby at Kootenay Lake. Further, the authors indicated that current operations used for flood control under a certain climate change scenario would result in decreased system-wide hydropower production in June and July at Libby. This would come at a time when future energy demand could rise due to increased air conditioning use from higher average temperatures (Hamlet et al. 2010b). The River Management Joint Operating Committee (RMJOC), established by the USACE and BPA to climate change impacts on system objectives, determined that shifts in runoff timing may require earlier draft of reservoirs. Specifically, the RMJOC concluded that the impact of climate change on Grand Coulee Dam and Libby Dam was not apparent due to inconsistent trends in flood control elevations resulting from the set of HD scenarios used for the study (USACE and BPA 2011).

Hydropower represents another objective in the PNW that could be impacted by changes in future climate. In a given year, hydropower accounts for nearly 70% of the energy supplied in the Pacific Northwest (PNW) (BPA et al. 2001). Its direct dependence on water timing and availability means it could be greatly impacted by changes in future climate. Many studies have sought to address this, namely by estimating the change in total PNW system hydropower generation and also the shift in seasonal availability of hydropower (Payne et al. 2004; Markoff and Cullen 2008; Hamlet et al. 2010b). Payne et al. (2004) examined the sensitivity of mitigating negative impacts of climate change proposed by Hamlet and Lettenmaier (1999) to system hydropower generation and found that generation decreased by anywhere from 9% in the 2020s to 35% in the 2080s. Decreases in generation were a result of both earlier reservoir refill and increased storage for summer instream flow requirements, which were done in an attempt to mitigate reservoir system losses due to climate change. With a more expansive set of climate change scenarios from the IPCC's Third Assessment Report (TAR) and AR4, Markoff and Cullen (2008) found changes in generation for the same future timeframes. One 2020s climate scenario showed a modest increase in average annual generation of approximately 3%, while others decreased by approximately 8–16%. By the 2050s and 2080s, maximum decreases in annual generation were greater. For instance, of all 2080s scenarios they used, 19 out of 24 TAR scenarios and 17 out of 20 AR4 scenarios showed decreases in generation, ranging from nearly zero decrease to upwards of 40%. Hamlet et al. (2010b) found similar annual decreases during the 2020s of 0.8–3.4%, but average decreases of only 2.6–3.2% in annual 2080s generation. Christensen et al. (2004), on the other hand, examined climate change impacts at three reservoirs in the Colorado River basin and found significantly greater effects; system generation decreased by 56, 45 and 53% for the 2020s, 2050s, and 2080s timeframes, respectively. In Quebec, Canada, Minville et al. (2010) examined climate change impacts on the Peribonka system and found hydropower changed by -12 to +2% by the 2050s. The effect on Europe's hydropower system has also been examined, with results indicating overall decreases of approximately 6% by the 2070s (Lehner et al. 2005).

2.2 Water Agreements

Water agreements in the modern era often involve multiple stakeholders and span political and jurisdictional boundaries, thus requiring binding agreements to ensure all parties have their needs met to the extent possible. For example, the Colorado River Compact was negotiated between the seven states in the Colorado River Basin and the federal government and divides the basin into upper and lower regions to manage the allocation of water. In broad terms, the majority of transboundary water agreements represent cooperation between the parties (Wolf et al. 2003), while others are complex and entail more than just simple conflict or cooperation (Zeitoun and Mirumachi 2008). Sadoff and Grey (2002) point out that identifying the benefits shared from collaboratively managing the river are keys to better use of the water and the cooperation amongst the parties. The U.S. and Canada sought to achieve this with the CRT, which is generally regarded as an example of a successful cooperative effort (McKinney 2011). Originally designed to manage flood control and hydropower, the CRT has recently gained more attention as the potential termination or renegotiation of the agreement nears. Studies related to the alternative outcomes of the treaty have been conducted by water managers, but have not considered climate change in their evaluation (USACE et al. 2010b). However, consideration of the potential for climate change in the CRB to impact transboundary water agreements like the CRT has been noted in the past (Cohen et al. 2000; Hamlet 2003) and continues to create dialogue as the potential end of the CRT nears (Cosens 2010; Hamlet 2011; Paschal-Osborn 2012).

2.3 Reservoir Models

Since the advent of HEC-3 in 1965 (HEC 1981), there has been a proliferation of reservoir models developed by various organizations, researchers, and private companies. For instance, large scale programs exist for modeling system-wide hydropower generation at a monthly timestep (Hamlet and Lettenmaier 1999; USACE et al. 2010c). They are typically used for longer-term planning studies and often do not utilize highly detailed information on each facility. Other models simulate generation close to real-time and would require, for example, specifications of a single turbine within a powerhouse. Simulation models exist in both public and private sectors; some are free to the public and others are proprietary. With numerous programs available for reservoir simulation it is important to utilize one best suited to the objectives of the study. The remainder of this section outlines five of the models considered for this study and how their features and characteristics relate to the primary objectives. A summary is provided in Table 1.

Table 1. Summary of reservoir simulation models.

Model	Developer	GUI?	Proprietary?	Generalized?
RiverWare	University of Colorado	Yes	Yes	Yes
MODSIM	Colorado State University	Yes	No	Yes
HYDSIM	BPA	No	No*	No
COLSIM	University of Washington	Yes	No*	No
HEC-ResSim	USACE	Yes	No	Yes

*Free, but not easily obtainable or requires special permissions

The first model discussed is RiverWare, developed through the Center for Advanced Design Support for Water and Environmental Systems (CADSWES) at the University of

Colorado. The program is described at length by Zagona et al. (2001). The tool features a graphical user interface (GUI) and offers both simulation and optimization capabilities. A disadvantage of this program as it relates to this study is that RiverWare is proprietary. An academic single-user license for one year costs over US $2,000 and US $1,200 for each renewal according to the CADSWES website (http://cadswes.colorado.edu/riverware). A government or commercial license is over US $6,500. This could make certain water agencies and stakeholders less willing to use or adapt the model to suit their needs. Nonetheless, the program offers all the capabilities required to address the problems presented in this study.

Another program from the state of Colorado is MODSIM, first developed in 1978 at Colorado State University (Labadie 2010). MODSIM has mostly been implemented for the analysis of the Colorado River basin, but also for Pacific Northwest systems like the Upper Snake (Miller et al. 2003) and the Deschutes River (La Marche 2001) basins. Like RiverWare, MODSIM utilizes a GUI and allows for generalized simulation and optimization of any reservoir system. An advantage of MODSIM over RiverWare is that the program is non-proprietary and can be obtained directly from Colorado State University.

The Bonneville Power Administration uses the hydropower regulation model, HYDSIM, for use in their long-term planning studies, including studies related to CRT operations (USACE et al. 2010c). Its central role is to determine hydropower generation, project outflows and storage volumes at projects in the CRB under varying inflows, power requirements, and other system constraints. The monthly time step model was developed specifically for the CRB and does not have optimization capabilities or a GUI. Use of the model is non-proprietary, but it is not easily obtainable or implemented and would likely require authorization from both BPA and BC Hydro because it is jointly developed between the U.S. and Canada for the CRT (Chisholm 2012).

COLSIM, as described by Hamlet and Lettenmaier (1999), is a reservoir system model developed by researchers at the University of Washington and has been in use since 1997. Like HYDSIM, COLSIM was designed specifically for the CRB. The model was created using STELLA® II by High Performance Systems, Inc., which also provides a GUI. The model incorporates most of the large dams in the CRB and operates on a monthly time step. Some simplifications of the reservoir system do exist, however, such as lumping together multiple reservoirs and assuming they operate as one. It has been used extensively for analysis of climate change impacts in the CRB and continues to be implemented (Hamlet et al. 2002; Markoff and Cullen 2008; Lee et al. 2011).

The Corps has also developed numerous reservoir simulation tools including HEC-3 (HEC 1981), HEC-5 (HEC 1989), HEC-ResSim 2.0 (HEC 2003), and most recently, HEC-ResSim 3.0 (HEC 2007). HEC-ResSim (ResSim) in particular has been successfully implemented for the analysis of multiple reservoir systems throughout the U.S. and the world (Wurbs 2012). It was designed by the Hydrologic Engineering Center (HEC) of the U.S. Army Corps of Engineers specifically for aiding in decision making processes for reservoir operations and planning (HEC 2007) and is the predecessor to the widely used HEC-5 program. The program has been updated to include a number of improvements over time to allow users to control additional operational parameters and access output results in more intuitive formats. ResSim utilizes a GUI to allow point-and-click model construction and can operate on multiple user-defined time steps. The 1-dimensional program uses a rule-based approach to govern reservoir release, from which hydropower can be generated. Reservoirs are divided into vertical zones having rules associated with each and total storage is determined by a storage-elevation-area relationship. The model is purely descriptive, in that it does not have optimization capabilities. The program can also be used with a visual utilities program, HEC-DSSVue (HEC 2009), to manipulate input and output datasets or create plots and other graphics.

2.4 Study Area

The study site is Libby Dam (Libby), located on the Kootenai River in Northwestern Montana (see Figure 2). Libby collects water from a northern region of the 259,500 square-mile Columbia River basin (CRB), which spans seven Northwest states and one Canadian province. The majority of Washington, Oregon, and Idaho, as well as parts of Montana, Nevada, Wyoming, and Utah lie within the U.S. portion of the CRB, while southeastern British Columbia comprises the Canadian side. At approximately 18,000 square miles, the Kootenai River watershed is the third largest drainage area in the CRB and contributes almost 20% of the total water in the lower Columbia. Libby is just west of the Rocky Mountain Range where elevations reach about 12,000 feet and most summit elevations are between 6,000 and 7,500 feet. Ninety percent of the basin is forested or above the tree-line and precipitation generally amounts to around 20 inches with snowfall anywhere between 40 and 300 inches (Kootenai River Network 2013). Snow is held in natural storage in the mountains until warmer temperatures in spring cause runoff, which ultimately enters the Kootenai River via its tributaries. The spring runoff, or freshet, usually begins in mid-April and reaches a peak flow in early June. Figure 1 shows observed inflows to Libby for the 1976–2006 period. The solid black line gives the average inflow for this period and dotted lines represent the 90^{th} and 10^{th} percentiles on a daily basis.

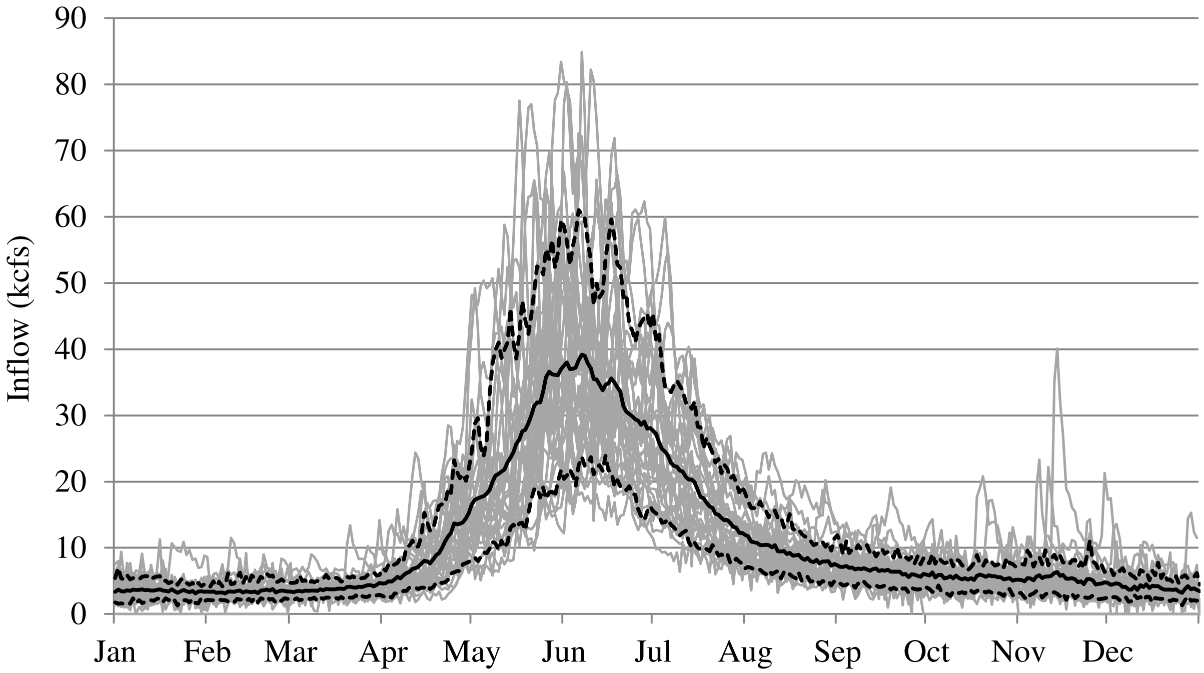

Figure 1. Daily observed inflow to Libby.

Figure 2 shows a map of the CRB and the locations of major federal and non-federal dams in the area. The number of dams is misleading compared to the total amount of storage in the basin because many dams are “run of the river” facilities with little to no storage capacity. In fact, only approximately one third of the average annual flow is captured (BPA et al. 2001).

Libby was completed in 1972 under authorization of the Columbia River Treaty and operates to prevent both local and downstream flooding. The impounded reservoir, Lake Koocanusa (an amalgamation of Kootenai, Canada, and the United States of America), has a usable storage capacity of about 4.9 million acre-feet (Maf) and a total capacity of nearly 6 Maf. The reservoir is approximately 90 miles in length, about 40 of which extend into British Columbia. The minimum allowable reservoir elevation is 2,288 ft with a maximum of 2,459 ft, equating to 172 ft of operating range. Five 120 MW turbines also provide a total generating capacity of 600 MW. BPA markets the hydroelectric power generated at Libby to the public and other utilities.

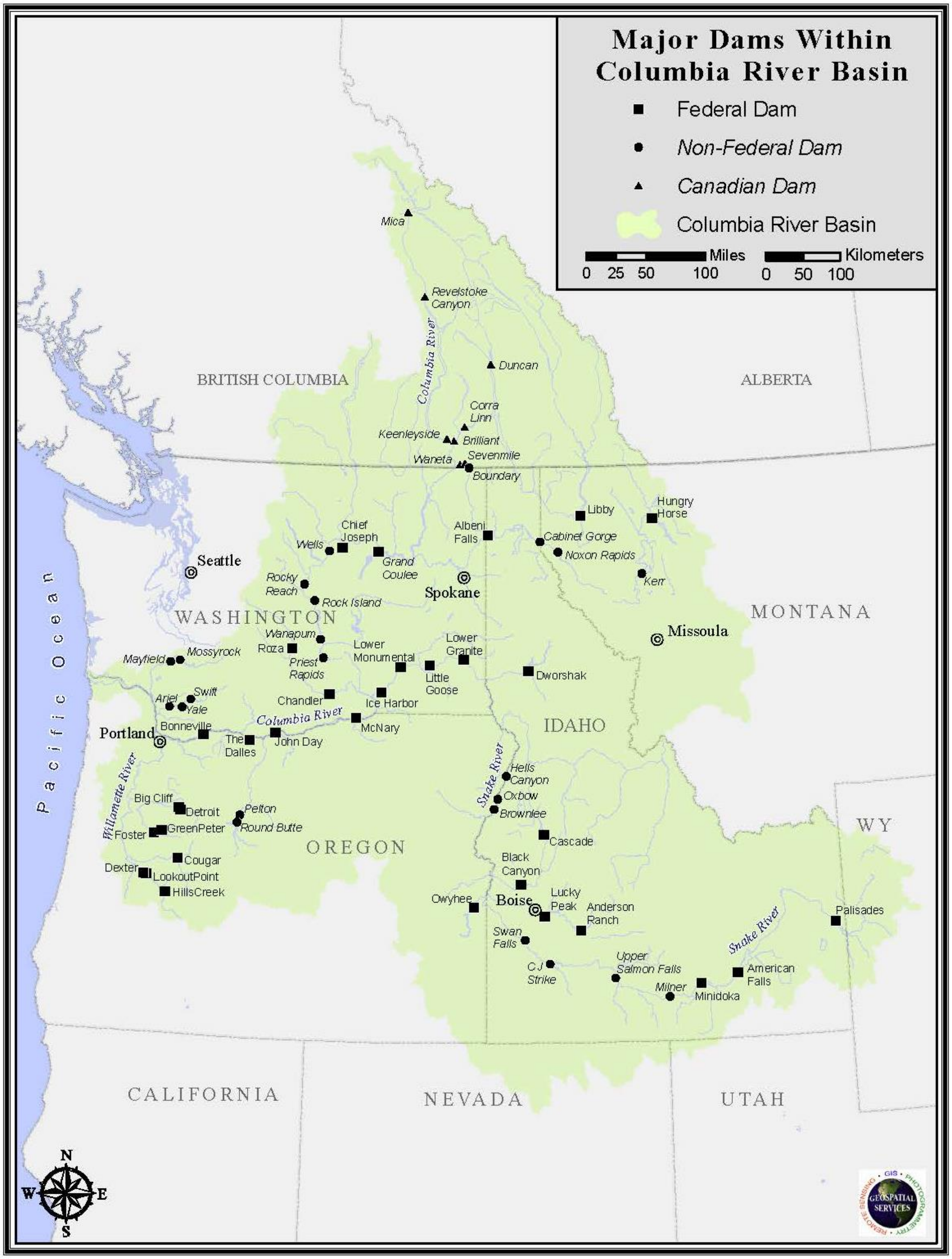

Figure 2. Major Columbia River basin dams (source: BPA).

For each water year, operators determine the required reservoir elevations such that Libby has a high probability of meeting its many objectives. These objectives include flood control (both at local and regional scales), power generation, meeting instream flow requirements, and recreation. Target elevations are based on different objectives for different times of the year. For example, elevations must be high enough throughout winter to provide release to generate power needed for heating. On the other hand, elevations must be low enough in early spring to hold the expected runoff entering the reservoir and prevent flooding. The volume of water released, or evacuated, from the reservoir in spring depends on the volume of runoff forecasted to enter the reservoir during April through August (USACE 1991). A higher expected runoff volume corresponds to a higher evacuation volume. The beginning and duration of the evacuation period depends on the forecasted volume of runoff, but usually starts at the end of December and is to be completed by March 15.

Chapter 3: Methodology

This chapter details the selection, development, and evaluation of the reservoir model and discusses the operational alternatives used to address objectives 1, 2, and 3 as described in Chapter 1.3. First, criteria for selecting a reservoir model were chosen based on the ability to replicate the physical characteristics and operations of Libby and on the data available. Second, the models were compared against these criteria. Then, the third step was to use the preferred model with existing information to replicate historic operations at Libby. A range of climate scenarios was chosen based on the objectives of the study and available information. The model results were then evaluated using specific metrics to determine the validity of model response. Lastly, alternatives were developed to test the sensitivity of changing certain operations under climate change conditions.

3.1 Model Selection

A model for this study was selected based on a number of criteria. Primary for purposes of this study was a user-oriented generalized model. The model required the flexibility to operate using different rules and to test the sensitivity various input conditions in an efficient manner. Ease of use and adaptability were also crucial; in other words, a GUI and tools for managing input and output data were desired. Also important was a non-proprietary model that demonstrated acceptance from both research and management communities.

ResSim (described in Chapter 2.3 Reservoir Models) is non-proprietary and easily obtainable from the U.S. Army Corps of Engineers software website (http://www.hec.usace.army.mil/software). It can therefore be used free-of-charge on an ongoing basis as long as the user has the proper hardware requirements. User support documents are also easily obtainable and there are ample Corps reports that have utilized ResSim to some degree, allowing for simple model construction and guidance. Ongoing efforts ensure the program is updated and improved upon. Above all, ResSim has the capability to perform all tasks required to address the objectives of this study, namely simulation of Libby's operation under different water conditions and alternative operating strategies. The objectives of this study do not require analysis of Libby's operations at the sub-hourly level or optimization of power generation from individual units in the powerhouse. Though models do exist for this, the objectives of this study can be met without this level of detail. Likewise, basin-wide models such as COLSIM, for example, would not be as efficient for running multiple simulations using different operational alternatives. For these reasons, ResSim has key advantages over the others listed here and was therefore chosen for this study.

3.2 ResSim Model

To address Objective 1, HEC-ResSim was used to replicate Libby Dam and its operations. The program was downloaded and installed on a Windows 7 machine. Once this was completed, physical characteristics of Libby and Lake Koocanusa were needed to start the model building process. The majority of this information was obtained from various Corps reports and documents, as well as a version of the COLSIM model that was acquired from the University of Washington.

The first step was to incorporate a basemap of the Kootenai River so that it could be aligned to scale within the model. Other large river networks in the basin were also included in the basemap to allow for future model expansion, but only the Kootenai River downstream to

Libby is considered in this study. Streamflow routing through the reservoir was neglected in the ResSim model because future streamflow data were representative of those at the dam and not at the headwaters of Lake Koocanusa, which is approximately 90 miles upstream. Water in the reservoir lost due to evaporation was also neglected.

Each elevation of the reservoir corresponds to a certain storage volume in Lake Koocanusa. The volume ranges from just under 1 million acre-feet (Maf) at the minimum allowable elevation (minimum pool) of 2,288 ft to nearly 6 Maf at the maximum pool elevation of 2,459 ft, giving Libby 172 ft of operating range. The elevation of the tailwater was assumed to be a constant 2,118 ft. Figure 3 shows the relationship between elevation and corresponding storage volume of Lake Koocanusa from COLSIM. Other physical characteristics of Libby and Lake Koocanusa are given in Table 2.

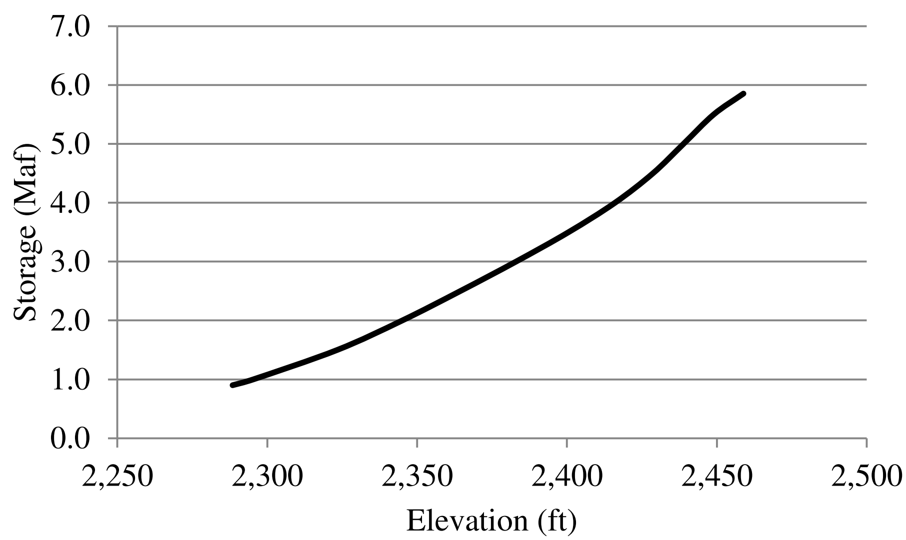

Figure 3. Storage-elevation relationship for Lake Koocanusa.

Table 2. Selected Libby and Lake Koocanusa physical characteristics.

Reservoir	
Total usable storage capacity	4,979,468 af
Total length	90 miles
Maximum pool elevation	2,459 ft
Minimum pool elevation	2,288 ft
Dam	
Top length	2,887 ft
Top elevation	2,472 ft
Height above tailwater	354 ft
Spillway/sluiceway capacity	206,000 cfs

The reservoir is operated with a minimum instantaneous outflow of 4,000 cfs per the 2012 Water Management Plan (BPA et al. 2011). Also outlined in this document are seasonal restrictions on the rate at which outflows from the dam can change, or ramping rates. Ramp-up and ramp-down rates depend on outflow and time of year, but generally range from 2,000–5,000 cfs and 500–1,000 cfs, respectively. These limitations exist primarily to maintain ecosystem function and protect aquatic species. For example, if the outflows from Libby decrease (ramp down) too fast, fish may become stranded in floodplain pools downstream. In the ResSim model, the ramp-up rate was set to 5,000 cfs per hour and the ramp-down rate to 500 cfs per hour for simplicity.

In actual operation, the efficiency of the powerhouse depends on the flow through its penstocks. As a conservative estimate, the efficiency of the powerhouse in this model was assumed to be 93 percent for all flow rates (see power evaluation in Chapter 3.4). Power generation was assumed to be zero at the 2,288 ft minimum pool elevation, increasing linearly to the 600 MW maximum power capacity at the 2,459 ft maximum pool elevation. In actual operation, maximum discharge is reduced both below and above an elevation of 2,420 ft because of the lower head above the turbines and the maximum output of the powerhouse, respectively (USACE 2005). The five 120 MW units currently installed in the powerhouse were assumed to be one 600 MW unit with a hydraulic capacity of 25,000 cfs.

Reservoir storage and release decisions are guided by what are known as “rule curves”, which determine target elevations for the reservoir to meet its operational objectives. These are dependent upon the historical record as well as forecasts of the expected runoff during spring (Hamlet and Lettenmaier 1999). Externally from ResSim, one of five flood control curves (FCCs) is chosen based on a storage reservation diagram (SRD) that stipulates the volume of storage space needed to meet elevations for flood control (USACE 1991). Figure 4, adapted from a Corps report on Libby operations (USACE 1998), shows the SRD used for the project. Five different paths are shown based on the required storage space in Koocanusa in any given year. The required storage space for each spring is dependent on the December forecast of the total volume of water entering the reservoir from April through August for that year. For example, the first path (top of Figure 4) denotes the space required at the end of each month based on a forecast of 4.5 Maf or less for April through August. These paths and their respective forecast volumes are summarized in Table 3. Simply put, the higher the volume expected to enter the reservoir, the more storage space is required.

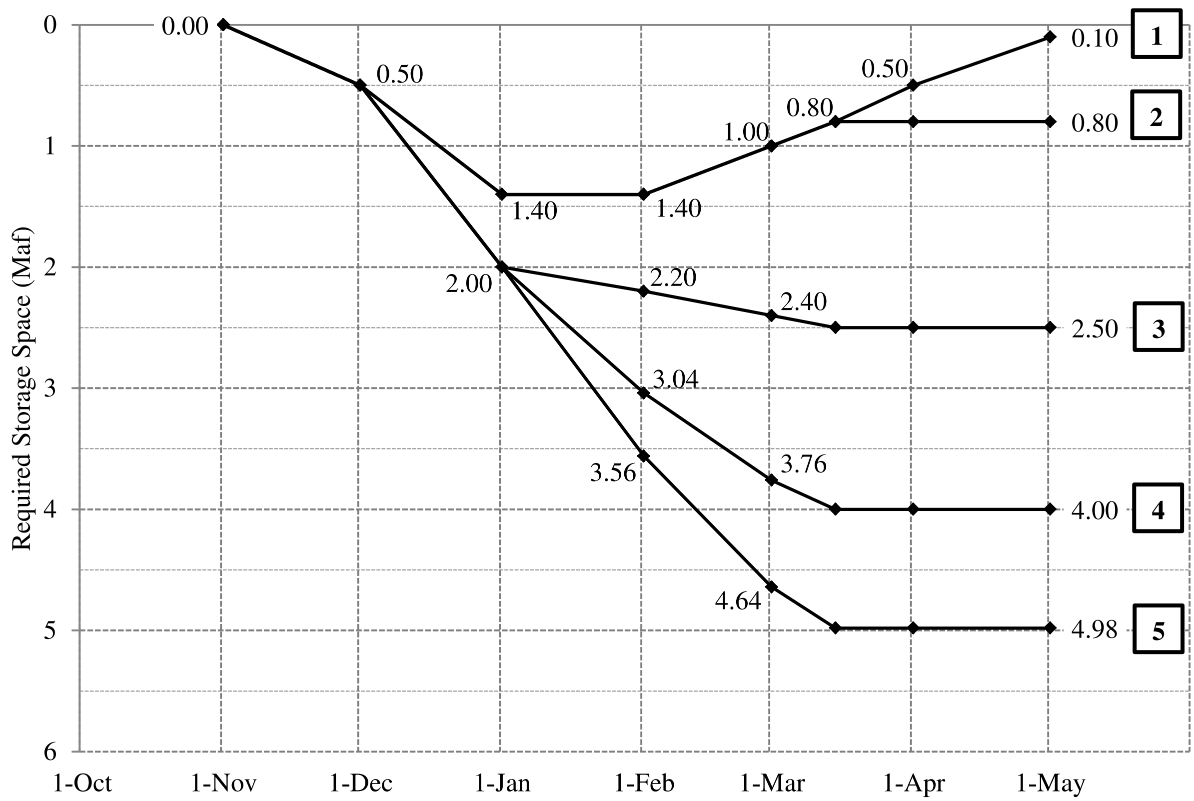

Figure 4. Storage reservation diagram (SRD) for Libby (USACE 1998).

Table 3. Forecast volumes corresponding to paths in Figure 4 (USACE 1998).

Path	April–August Forecast
1	less than 4.5 Maf
2	4.5–5.5 Maf
3	5.5–6.5 Maf
4	6.5–7.5 Maf
5	greater than 7.5 Maf

FCC elevations are set lower if the evacuation volume is high, and high if the volume is low. These represent the highest allowable elevations of the reservoir to ensure flood control goals are achieved. Like COLSIM, the ResSim model utilizes a perfect forecast of April through August runoff volumes to determine the required evacuation from Koocanusa for that spring (see for example, Payne et al 2004; Lee et al. 2009). Energy content curves (ECCs), on the other hand, represent the lowest elevations such that the reservoir's Firm Energy Load Carrying Capability (FELCC) can be supplied (USACE 1997). ECCs are calculated each year to determine the energy that the dam can feasibly supply at all times based on the expected water supply for that year. Calculation of these curves was outside the scope of this study, but because they are needed to reasonably represent the operation of the dam, values were obtained from HYDSIM output (USACE and BPA 2011). In normal operation, if the FCC is lower than the ECC, the FCC has precedence and is chosen as the target (USACE and BPA 2011). When the ECC is lower, it is chosen as the target because flood control goals will still be met.

ResSim requires that a guide curve be established to provide the model with target elevations. The model attempts to achieve these targets by storing or releasing water while meeting operational constraints—such as minimum and maximum pool elevations and outflow requirements—to the extent possible. For simplicity, the guide curve, or operating rule curve (ORC), was assumed to be the midpoint value of the ECC and FCC for each year. Figure 5 shows how these three curves are related, using 1993 as an example. In this case, when the ECC is higher than the FCC, flood control goals are not necessarily met because the elevations are too high (i.e. sufficient drawdown is not achieved). Firm energy supply also will not be met. Conversely, when the FCC is higher than the ECC, the midpoint ORC allows better certainty of energy supply through summer and still maintains flood control.

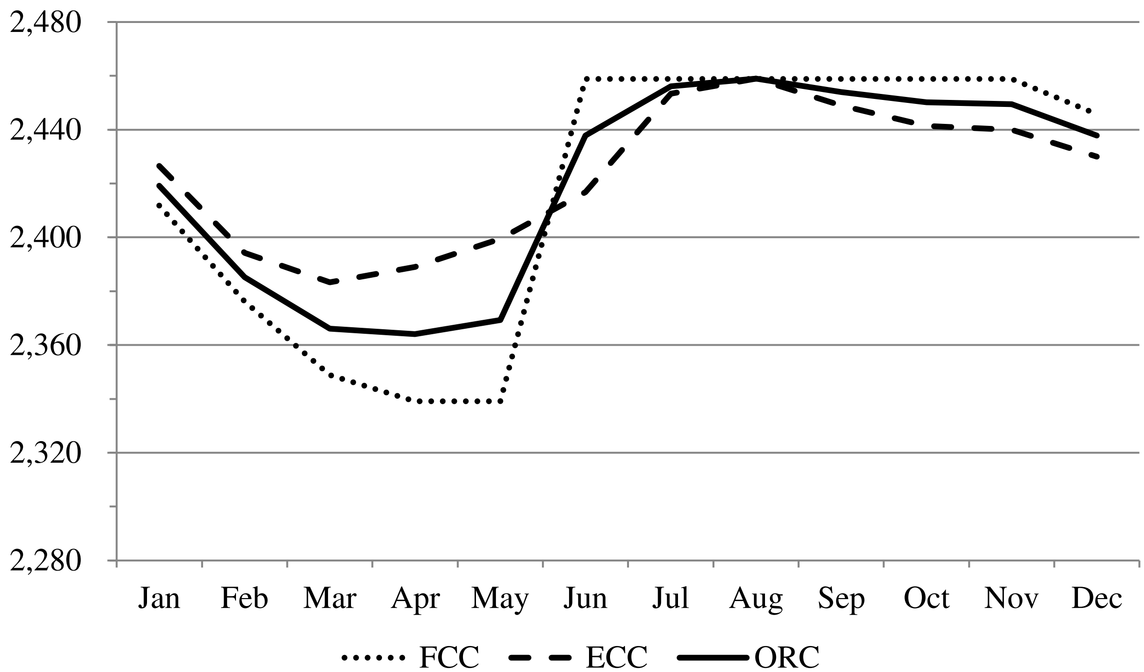

Figure 5. Rule curves for 1993.

3.3 Climate Scenarios

The climate scenarios chosen for this study are based on various general circulation models (GCMs) driven by either the A1B or B1 emissions scenario as outlined in the IPCC's Fourth Assessment Report (AR4) (IPCC 2007). Hamlet et al. (2010a) downscaled this information to a regional level using the hybrid-delta (HD) method and created 57 model runs using 10 A1B and 9 B1 scenarios over 3 future timeframes. A subset of these scenarios was chosen in previous studies as providing the best representation of future climate in the Pacific Northwest (USACE and BPA 2011) and were the scenarios used in this study. These scenarios are summarized in Table 4, where changes in precipitation (P) and temperature (T) represent averages at the CRB scale. Hamlet et al. (2010a) used these changes in precipitation and temperature in the VIC hydrologic model (Liang et al. 1994) to determine changes in streamflows at 297 points in the CRB for the 2020s and 2040s timeframes (Hamlet et al. 2010a). The future daily streamflow estimates for Libby, as well as VIC-modeled historic daily streamflows were obtained from the Climate Impacts Group (CIG) (CIG 2012) and used to drive the ResSim model to determine differences in operational objectives, such as flood storage and potential hydropower generation. All streamflows were previously bias-corrected (Wood et al. 2002). The climate scenarios are denoted by changes in temperature and precipitation and the naming convention is as follows: Central (C), Minor Change (MC), More Warming and Wetter (MW-W), Less Warming and Wetter (LW-W), More Warming and Drier (MW-D), and Less Warming and Drier (LW-D) (USACE and BPA 2011). VIC historic flows cover the water years of 1928–1998, while the climate scenarios use these same years' conditions projected into the 2020s and 2040s. Hamlet et al. (2010a) covered a larger historic period of the 1916–2006 water years, but because ECC information from HYDSIM was only available for 1928–1998, this was the 70-year period covered in this study.

Table 4. Climate scenarios for the 2020s and 2040s timeframes.

2020s				
GCM	Emissions Scenario	Climate Scenario	Change in P (in)	Change in T (°C)
HADCM3	B1	C	3.8	1.0
ECHAM5	A1B	MC	3.7	0.7
IPSL CM4	A1B	MW-W	7.4	1.6
CGCM3.1 (T47)	B1	LW-W	7.9	1.1
CCSM3	B1	MW-D	-1.2	1.4
PCM	A1B	LW-D	-1.5	1.0
2040s				
GCM	Emissions Scenario	Climate Scenario	Change in P (in)	Change in T (°C)
HADCM3	B1	C	3.7	1.7
ECHAM5	A1B	MC	3.7	1.5
MIROC3.2	A1B	MW-W	14.2	2.7
CGCM3.1 (T47)	B1	LW-W	11.5	1.3
HADGEM1	A1B	MW-D	-2.5	2.8
ECHO-G	B1	LW-D	-7.9	1.8

Emissions scenarios are the key drivers of changes in future temperature and precipitation. The two emissions scenarios used in this study are the A1B and B1 scenarios, as described by the IPCC (2000). The A1B scenario represents a midrange emissions scenario having increased GHG emissions through the end of the 21st century and no particular focus on one particular energy source. The B1 scenario, on the other hand, emphasizes economic, social and environmental sustainability with focus on cleaner energy technologies.

3.4 Model Evaluation

Verification of model response is a crucial step in determining if the model operates similarly to actual operation. To accomplish this, evaluations of snow water equivalents (SWE), historic inflows, outflows, and power generation are presented in this chapter. The first two metrics, SWE and inflow, are intended to evaluate the use of VIC streamflows in the ResSim model, while outflow and power generation are used to test the model's operation as compared to that of the actual facility.

The snow water equivalent (SWE) of snowpack in the Kootenai River basin is an important determinant of runoff entering Lake Koocanusa. It was thus used for comparison with observed SWE values from stations in the area to help validate of use of VIC-generated streamflows in ResSim. Snow water equivalents derived using the VIC hydrologic model were obtained from the CIG website for Libby (CIG 2012). For observed data, a historic record of SWE was obtained from 5 of the meteorological stations in British Columbia and Montana that are used in forecasting runoff into Lake Koocanusa. There are nine stations used for SWE measurements in total; however, due to lack of data for four sites in Alberta, only five are shown in Figure 6. Wortman (2011) lists these stations and outlines the methodology for forecasting runoff volumes based on SWE, precipitation, and other climatic variables measured at the stations. VIC grid cells corresponding to the latitude and longitude of the stations were chosen for the SWE values. Figure 7 summarizes the monthly average SWE in inches of water for the period October 1992 through September 2006.

Comparisons shown in Figure 7 all show large differences in average monthly SWE except for Floe Lake (Figure 7a). The trends of increasing and decreasing SWE do seem to match in general, though. Ideally, if the VIC historic and observed SWE for every station matched as well as those for Floe Lake, this could indicate that resulting runoff at Libby would match accordingly due to the dependence runoff has on SWE. Because 4 of the 5 locations show large differences, this assumption cannot be made. However, comparing only one factor that affects runoff (SWE) when there are multiple others (e.g. precipitation) will not necessarily result in an accurate representation of inflow. Feng et al. (2008) found similar discrepancies between VIC SWE and observed values in a terrain comparable to that of the Kootenai watershed and attributed this to errors in atmospheric forcings, such as precipitation. Further, and most importantly, differences at the rest of the sites could likely be due to spatial discrepancies between the sites used for snow depth measurements and the 1/16th degree resolution of VIC. These sites, often located at high elevations, would likely measure higher SWE (due to deeper snowpack) than the VIC values because those are averaged across the grid cell in that model. In summary, inaccurate reproductions of SWE do not necessarily affect bias-corrected inflows to Libby, which are of highest importance in this study.

Figure 6. Locations of 5 meteorological stations used for Libby runoff forecasts.

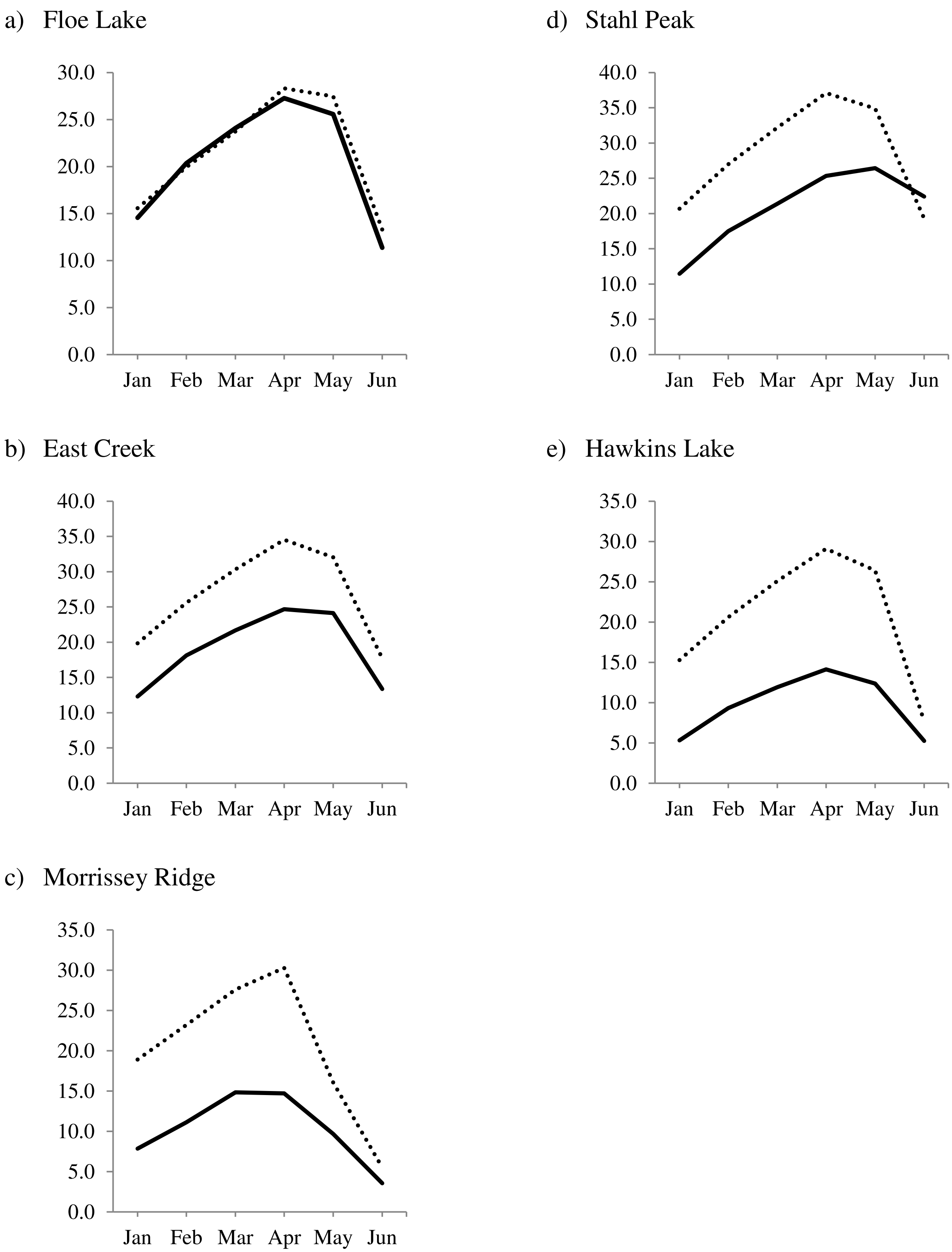

Figure 7. Average monthly VIC historic (solid line) and observed SWE (inches of water).

The second parameter evaluated was inflow. Figure 8 shows a comparison of the average monthly inflows at Libby Dam for both the bias-corrected historic flows from the VIC hydrologic model (Hamlet et al. 2010a) and the observed values as measured by the Corps (DART 2013). Flows are relatively the same except during May, June, and July. This difference is likely due to the bias-correction process and is relatively modest on average; the maximum difference is only approximately 3,400 cfs in June. The total additional volume of runoff due to this deviation for the entire 1975–1998 period equates to approximately 14.5 Maf.

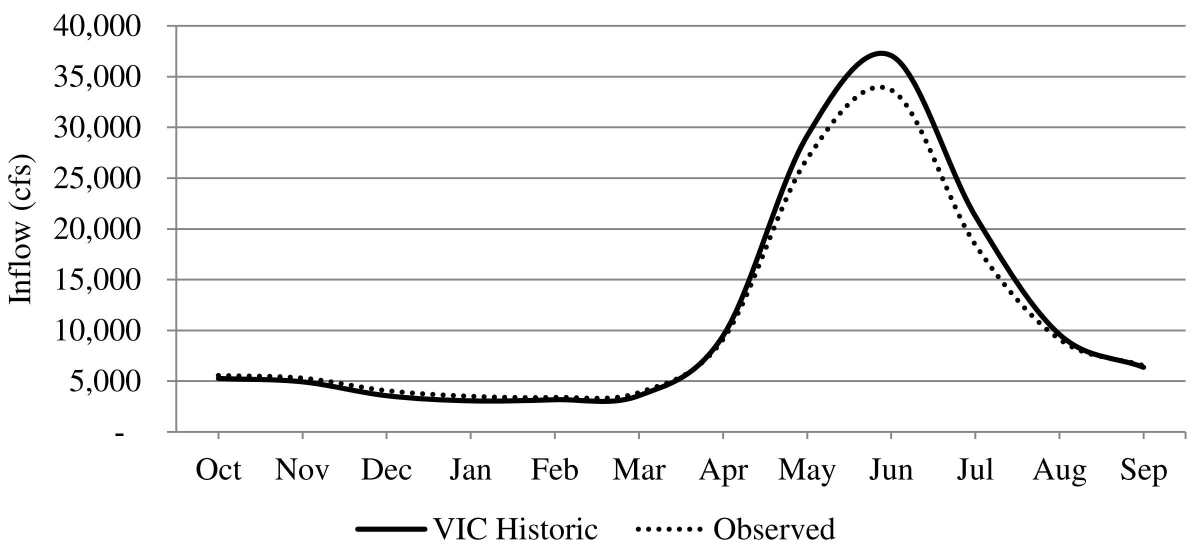

Figure 8. Average monthly inflow for water years 1975–1998.

A significant metric for evaluating the performance of a reservoir model operation is the ability to reproduce regulated flows, or those influenced by the operation of the dam (Modini 2010). Figure 9 shows a summary of the average monthly outflows from the ResSim model when using the VIC historic inflows (Figure 8) as compared to the observed outflows from Columbia River DART (2013). A key consideration in analyzing Figure 9 is that observed outflow incorporates releases from Libby to satisfy firm energy demands from the facility. With peak energy demand in the region occurring during winter, this explains the higher average outflows (in excess of 15,000 cfs) during this time versus summer when energy demand is lower and thus less water is released. Higher average spring and summer inflows from VIC (Figure 8) would contribute to higher outflows to achieve low target elevations during the spring drawdown. Further still, the modeling process used in this study incorporates Variable Discharge Flood Control (VARQ FC), which allows for higher outflows during the refill period for fish and to maintain system flood control (USACE 2006). This procedure was not reflected in the observed outflows because it was not implemented at the dam until after this period. In spite of the difference in June and July, the modeled outflow over the course of an average water year appears to follow a similar trend to observed outflows.

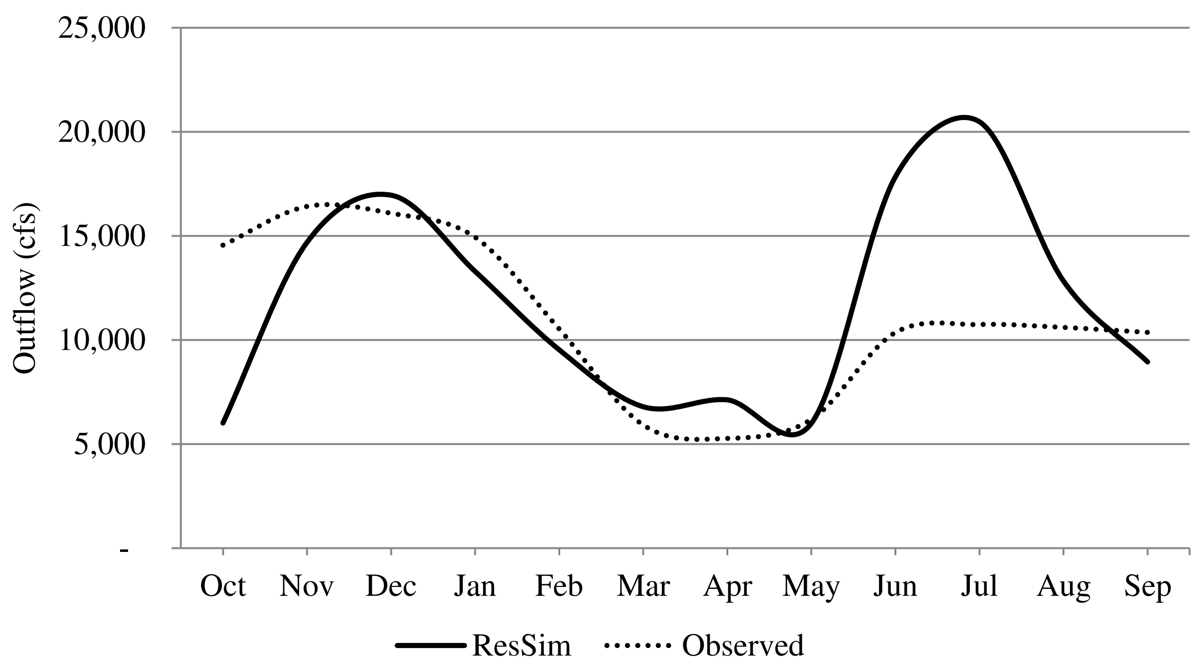

Figure 9. Average monthly outflows for water years 1975–1998.

Further assessment of the VIC historic inflows and ResSim modeled outflows revealed that the total volume of water that entered Koocanusa and was released from the dam was approximately 194 Maf and 191 Maf, respectively, for the 1975–1998 period. On the other hand, observed inflows and outflow were approximately 180 Maf and 178 Maf, respectively. These are shown in Figure 10. The difference between the VIC historic inflow volume and the ResSim modeled outflow volume when driven by those inflows was therefore about 3 Maf, while the difference in observed inflow and outflow volume was 2 Maf. These differences only amount to 1.6% and 1.0% of total inflow, respectively. Simply put, given the increase in average monthly inflow shown in Figure 8, differences in modeled volumes of inflow and outflow are virtually the same as those observed.

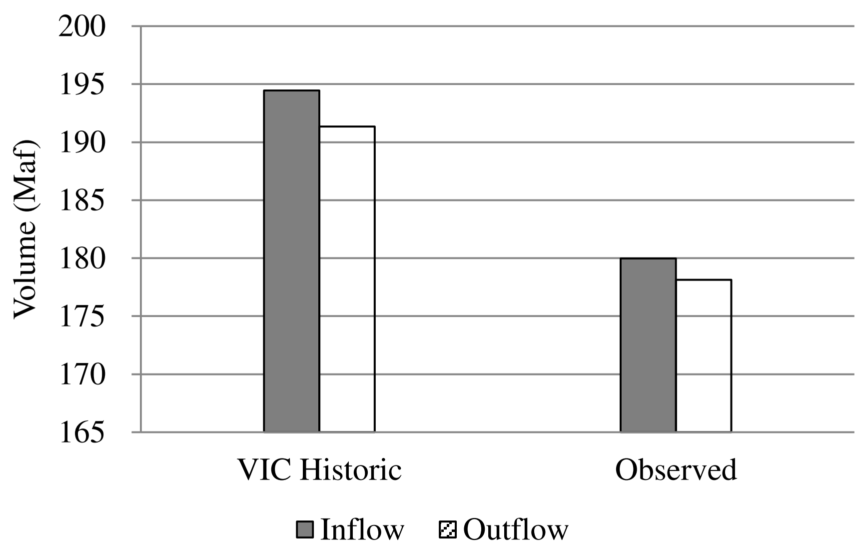

Figure 10. Total inflow and outflow volumes for water years 1975–1998.

The last step in the evaluation was to verify that potential power generation in the model was consistent with that of actual operation. To accomplish this, a power curve for one of the five units at Libby was used for comparison (USACE 2005). Power was calculated in the model for the period June 1, 1996 to June 15, 1996 using the VIC historic inflows as described previously. Table 5 shows the flow through the powerhouse for these days and corresponding reservoir elevation, head above the turbines, and power generated as calculated by the model. This period was chosen for evaluation because discharge through the powerhouse during this time was a constant 4,000 cfs. Because the hydraulic capacity of one unit at Libby is approximately 5,400 cfs, it was assumed that 4,000 cfs would pass through only one unit. Table 5 shows that head above the turbines ranged from 289 ft to 323 ft and corresponded to a range in average daily power generation of 90 MW to 101 MW, respectively. Dotted lines at these values, as well as a horizontal solid line representing the constant 4,000 cfs discharge during the 15 days, were added to the turbine discharge rating curve in Figure 11. Note that values along the red line correspond to all values of head (curved lines in increments of 20 ft) given in Table 5. This window of power generation and heads was determined by iteratively changing Libby's generating efficiency in ResSim until corresponding power and head values were obtained. Values represented in Table 5 were calculated using 93% efficiency for the dam. From these results, it was determined that power generation in the model was calculated accurately for a flow of 4,000 cfs. Because it is sufficient for the purposes of this study, the efficiency in the ResSim model was assumed to be a constant 93% for all flow rates, though in actual operation the efficiency is a function of the flow through the penstocks.

Table 5. Selected data for power calculation evaluation.

Day	Powerhouse flow (cfs)	Reservoir elevation (ft)	Head above turbine (ft)	Power (MW)
1	4,000	2,407	289	90
2	4,000	2,409	291	91
3	4,000	2,411	293	92
4	4,000	2,412	294	92
5	4,000	2,414	296	93
6	4,000	2,416	298	93
7	4,000	2,419	301	94
8	4,000	2,421	303	95
9	4,000	2,424	306	95
10	4,000	2,427	309	96
11	4,000	2,429	311	97
12	4,000	2,432	314	98
13	4,000	2,435	317	99
14	4,000	2,438	320	100
15	4,000	2,441	323	101

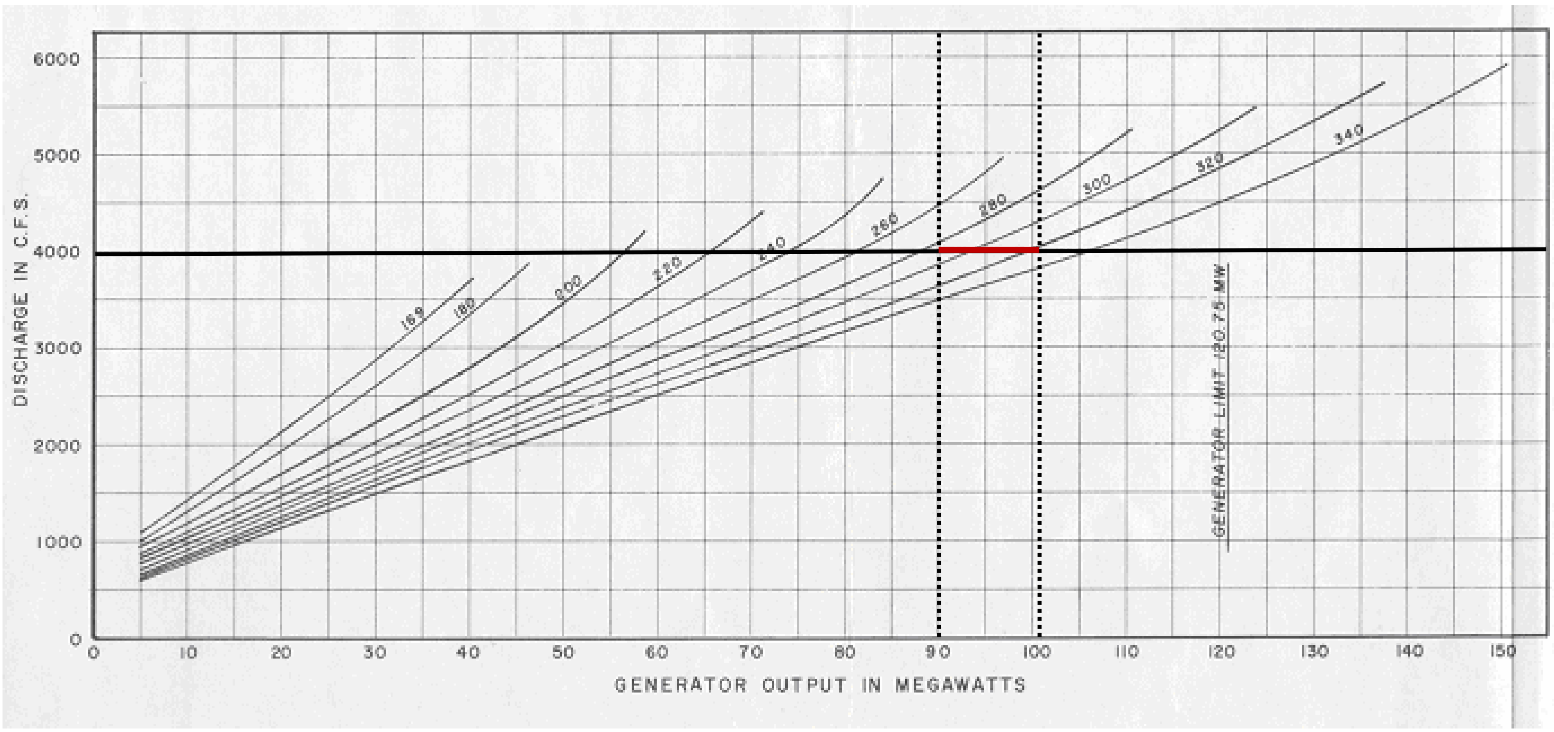

Figure 11. Libby turbine discharge rating curve (adapted from: USACE 2005).

3.5 Operational Alternatives

This study used the 12 climate scenarios given in Table 4 while running the ResSim model with various operational alternatives. These alternatives ranged from changes in target reservoir elevations at different times of the year to increased minimum reservoir outflow requirements. The water years 1928–1998 (and those same years' climate projected into the 2020s and 2040s) were used to examine overall changes in Libby's operational objectives. Operational objectives of interest in this study include potential hydropower generation, reservoir elevation/flood storage, and reservoir outflow. The operational alternatives used in this study are listed in Table 6.

Table 6. Summary of operational alternatives.

Alternative	Description
1	Reservoir target elevations based on ORCs
2	Maximum outflow restriction
3	Increased maximum pool
4	Increased outflow requirement; 10,000 cfs

The first of the alternatives was based on the 1928–1998 period and was intended to examine the main operational objectives of Libby: flood control and hydropower generation. The operation of the ResSim model under Alternative 1 used the ORC as the target elevations for the reservoir, in this case a combination of the respective FCC and ECC curve value for each month in the 70-year period. These curves are explained in Chapter 3.2. While still attempting to meet flood control and hydropower objectives, Alternatives 2–4 are intended to test the sensitivity of these objectives to climate change when introducing further system constraints not included in the first alternative. Alternative 2 puts a maximum on the outflow from the dam of 55,000 cfs at all times of the year, since this was highest discharge observed historically (DART 2013). Alternative 3 is designed to test whether increased storage above the normal maximum pool elevation of 2,459 ft would help reduce spill in a relatively wet year. The maximum pool elevation was increased by one foot to 2,460 ft, a procedure also used in the past (USACE 2012). Finally, Alternative 4 requires that 10,000 cfs be discharged from the reservoir during April, May, and June instead of the current requirement of 4,000 cfs as stipulated in the 2012 Water Management Plan (BPA et al. 2011) to analyze how increased outflow requirements could impact operational objectives in the future. An idea similar to this was introduced in the U.S. Fish and Wildlife Service's (USFWS) 2006 Biological Opinion (BiOp) (2006). Alternatives 2–4 do not use the entire 70-year period; these alternatives use shorter intervals from the period (e.g. a single water year) or just one future time period to remain concise yet still provide a good indication of the effects.

Chapter 4: Results and Discussion

This chapter presents the reservoir modeling results and discusses the results as they pertain to the original objectives of the study. The analysis is separated into categories of inflow and outflow, flood storage, and hydropower for the 2020s and 2040s. Alternatives involving spill and flow augmentation, as well as issues related to the CRT are also discussed. Any reference to "historic" flows, storage, power, or the like refers to model simulations that utilized the VIC historic inflows to Libby, and not the *observed* inflows as measured by the Corps. One reason for this was because VIC Historic inflows were available for years prior to observed flows due to the hydrologic model's ability to create naturalized conditions. This ultimately allowed for a larger period for simulation (1928–1998). Furthermore, future climate conditions in this study required a base case for comparison, and since these future conditions were based on VIC model output, it was most sensible to use historic conditions generated by the very same model.

4.1 Flow Comparison

Potential variations in streamflows at Libby under climate change may be a key driver of impacts to its operation and ability to meet objectives. At times, future inflows derived using VIC were seen to differ significantly from VIC historic inflows in both timing and magnitude. This chapter summarizes projected inflows at Libby under the 6 climate scenarios for the 2020s and 2040s.

4.1.1 2020s Climate Scenarios

Summaries of average monthly inflows for both the VIC historic data and 2020s climate scenarios are given in Figure 12. All scenarios show increases in late winter and early spring inflows compared to historic flows, with decreased late spring and summer flows. In general, there is a shift in the timing of runoff to earlier in spring primarily due to increases in future mean temperatures. This is the most important change from a reservoir management standpoint because earlier or deeper drawdown of the reservoir may be required to adapt to these changes.

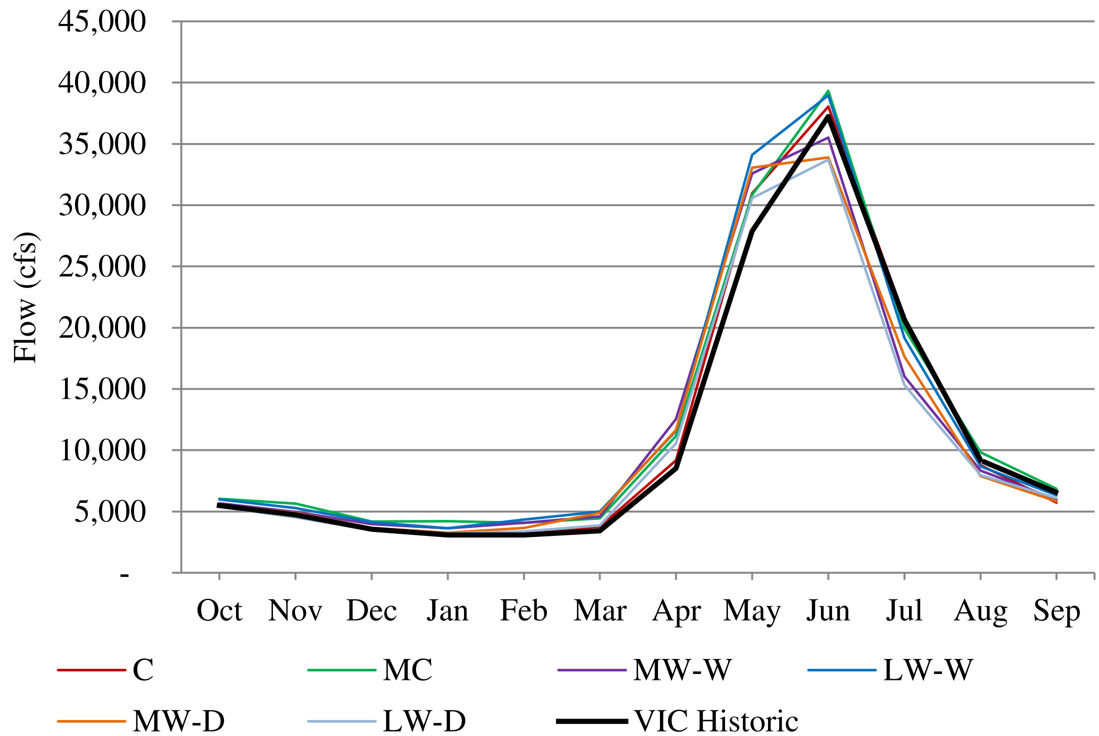

Figure 12. Average monthly inflows for 2020s climate scenarios.

To better depict the variation in future inflows, results for spring and summer months in individual dry and wet years were examined. For example, Figure 13 shows the inflow to

Koocanusa and total outflow from Libby for the spring and summer months in a dry year (1977). The historic April–August inflow volume for this year was only approximately 3.0 Maf, whereas the average volume for these months over the 1916–2006 period was 6.3 Maf. The figure shows peak inflow actually shifted from early May historically to mid-June for all the 2020s scenarios. Modeled outflow during this time was restricted to the minimum required outflow of 4,000 cfs for all scenarios due to the low inflows. Historically, outflow began increasing above the 4,000 cfs minimum at the end of August. Under the climate scenarios, outflow was required sooner in the year, starting at the beginning of July for the C scenario. Only the MW-D scenario showed an extension of the minimum outflow into the first week of September, indicating that the 2020s scenarios generally required more outflow throughout July and August. Total volume of water entering Koocanusa for the April–August period was also higher under every climate scenario for this year, which would result in higher outflows during summer. The forward shift in peak inflow from early May historically to June under the climate scenarios was contrary to results in Figure 12 and previous hypotheses. Further examination revealed that observed 1977 inflows (DART 2013) actually did reach a peak of 41,100 cfs in early June. Ultimately, the VIC historic data did not correspond well with the observed flows for this year. This is depicted in Figure 14.

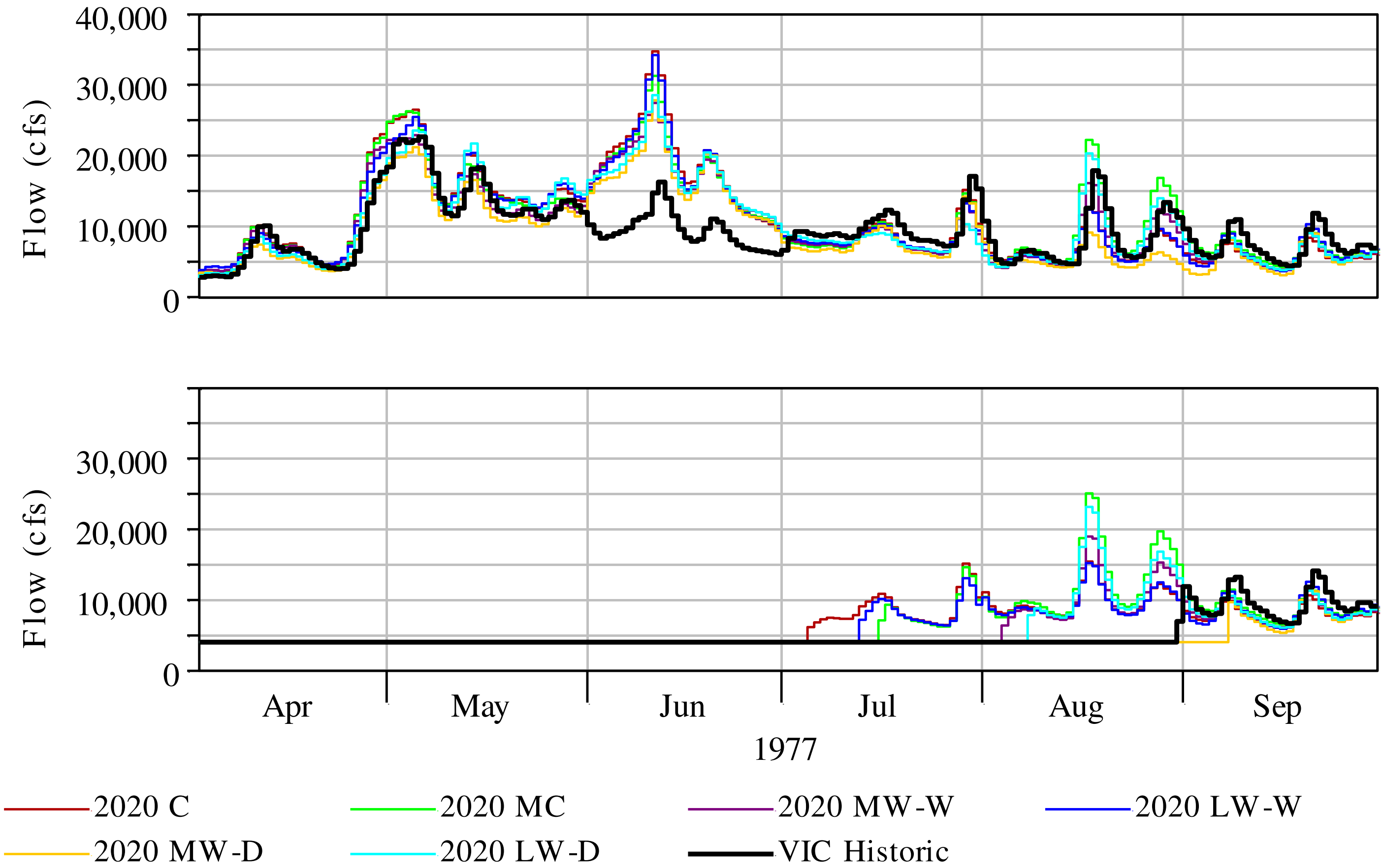

Figure 13. Inflow (top) and outflow for April–September 1977 (2020s).

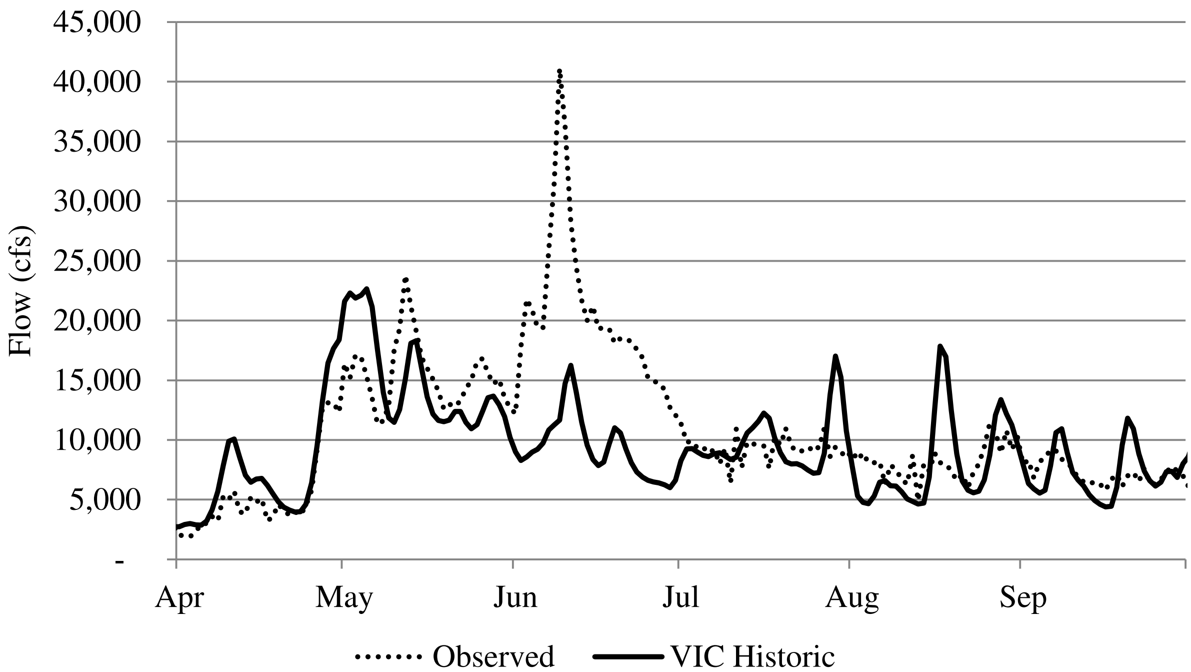

Figure 14. Observed and VIC historic inflow for April–September 1977.

Figure 15 shows the inflow and outflow for the spring and summer months in a wet year (1997), where the total April–August inflow volume was 11.5 Maf. Inflow historically peaked in mid-June, but under the climate scenarios this peak was generally not the case. Inflows were higher throughout early spring and by the historic peak in June were reduced. Inflows were lower than historic for all climate scenarios beginning in mid-June and through the end of summer. Due to the increase in early spring inflows, higher May outflows were required in an attempt to meet target elevations under all climate scenarios. By mid-June, when climate scenario inflows were lower than historic, outflows were also reduced.

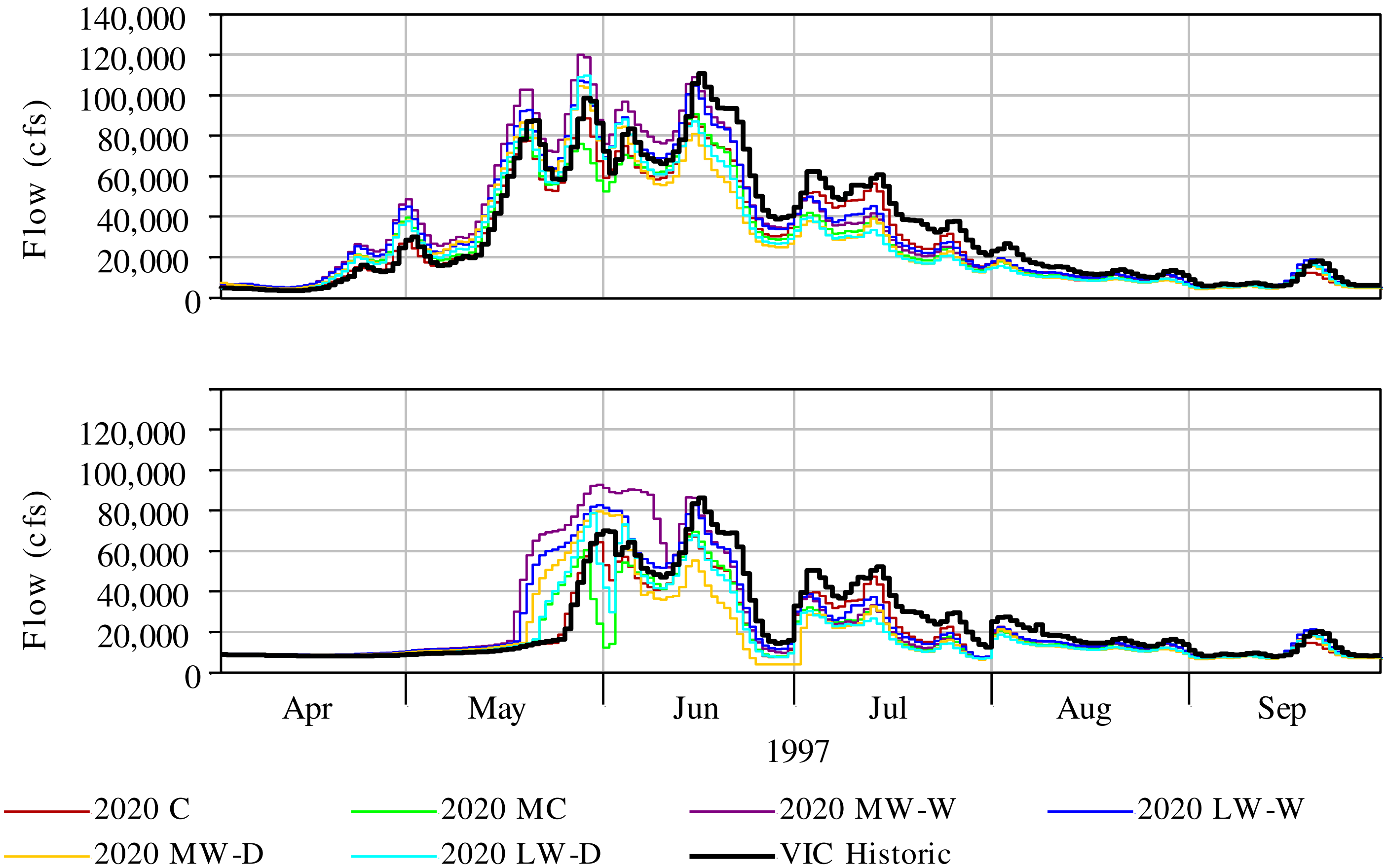

Figure 15. Inflow (top) and outflow for April–September 1997 (2020s).

4.1.2 2040s Climate Scenarios

Summaries of average monthly inflows for both the VIC historic data and 2040s climate scenarios are given in Figure 16. Similar to the results for the 2020s, all scenarios showed increases in late winter and early spring inflows compared to historic flows, with decreased late spring and summer flows. Again, there was a shift in the timing of runoff to earlier in spring, but magnitudes of change are greater than for the 2020s. For example, under the MW-W scenario average peak inflow was nearly 10,000 cfs greater than historic and shifted from June to May. In addition, the LW-D scenario showed that average peak flow also shifted from June to May, but approximately 5,000 cfs lower than historic.

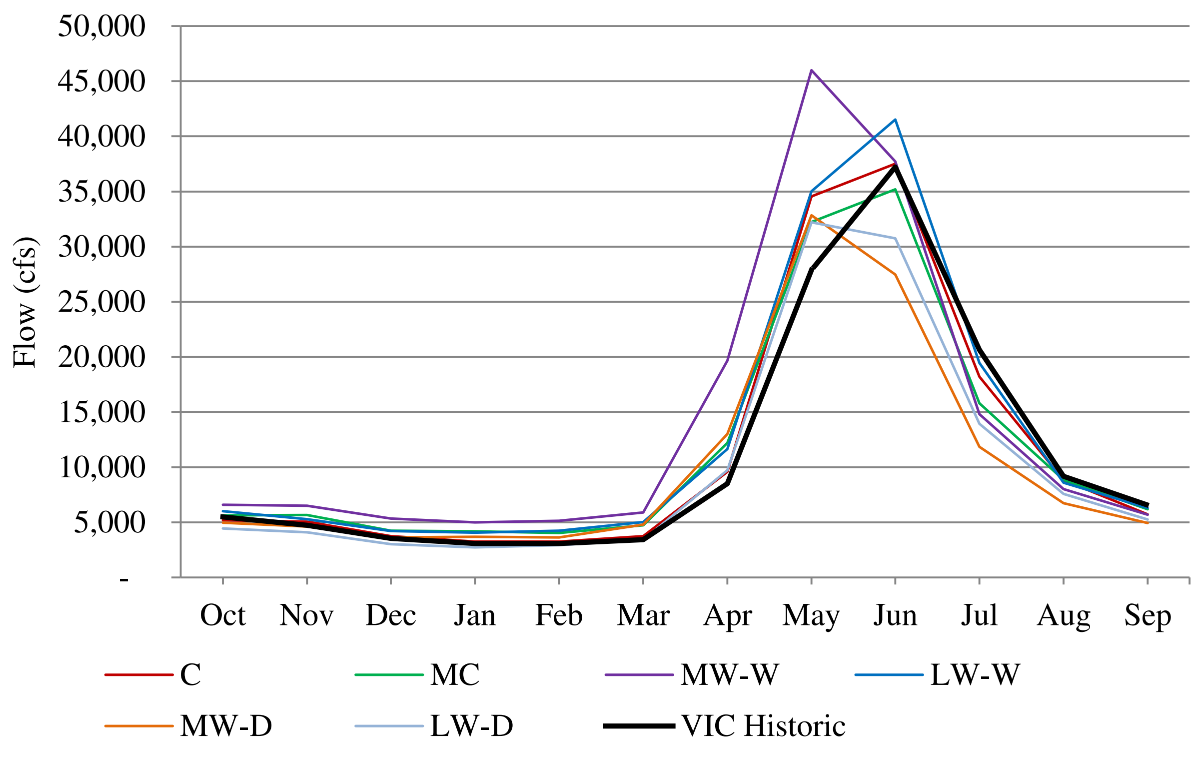

Figure 16. Average monthly inflows for 2040s climate scenarios.

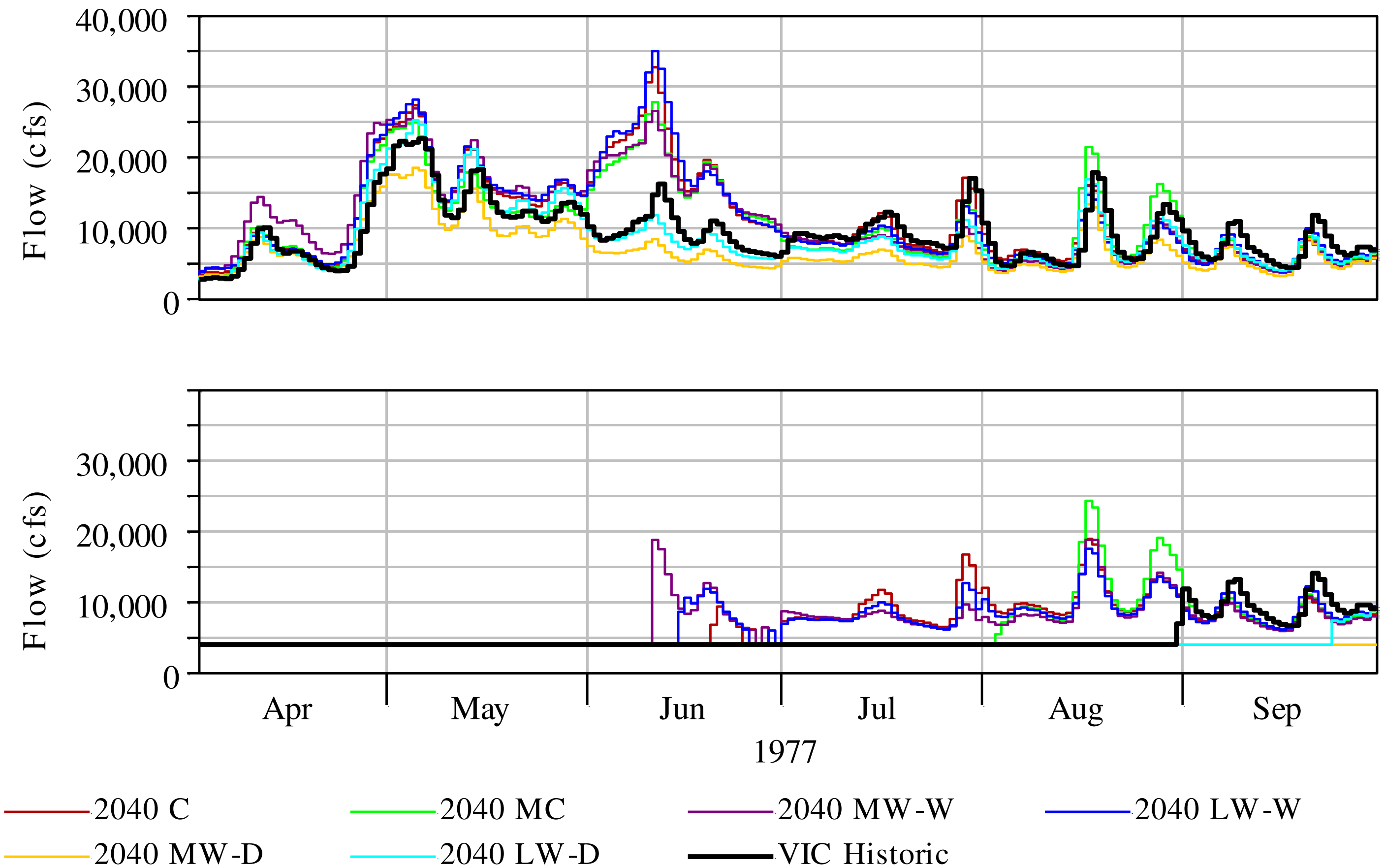

Figure 17. Inflow (top) and outflow for April–September 1977 (2040s).

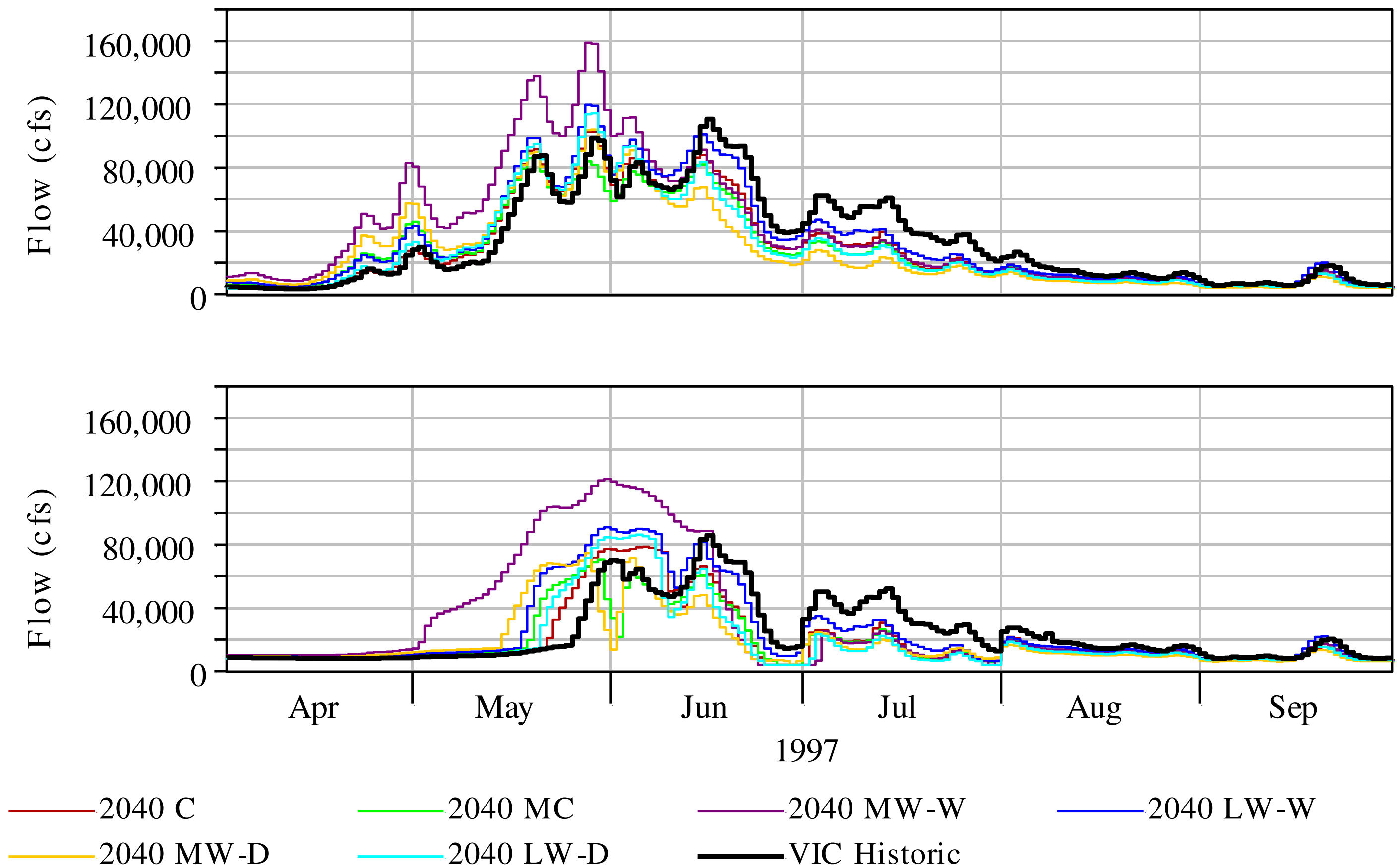

Figure 18. Inflow (top) and outflow for April–September 1997 (2040s).

4.2 Flood Storage

The ResSim model uses target elevations and reservoir zones to guide the operation of the dam. Water is either stored or released to attempt to meet the targets, which incorporate the ability to store flood water but also to have a high certainty of refilling by July 1. The methodology for examining the changes in flood storage capability was to compare elevations achieved in ResSim with those set as the target elevations, the ORCs. First, the model was run using VIC historic streamflows to determine resulting monthly elevations for all years in the 1928–1998 period. This results in a baseline for comparison with streamflows from each of the climate scenarios. Relative differences in reservoir elevations between each scenario and the baseline are provided in this section.

4.2.1 2020s Climate Scenarios

Figure 19 reflects the increase in average late-winter and spring inflows for the 2020s (Figure 12) in that elevations the model was capable of achieving during these months were higher than the targets. This figure shows how modeled elevations under each climate scenario differed from the elevations achieved using the historic inflows. For example, in February of the C scenario the model achieved an elevation of approximately 1.0 ft higher than the elevation achieved using historic flows in the model. For most of the scenarios during late winter and spring, constraints on outflow likely prevented the model from releasing enough water to meet first-of-month targets for the majority of the scenarios on average. By June however, when average inflows were lower than historic, target elevations were more easily achieved under all climate scenarios. This suggests during the drawdown period Libby did not have the capability—

due to both its operational and physical constraints—to release enough water to meet targets in an average 2020s year. Conversely, during the refill period (June) elevations were below targets on average. Elevations throughout summer and fall showed very little deviation (<0.5 ft) from their targets under any scenario, meaning the goal of refilling Koocanusa by July 1 was met to a high degree. The ability to meet summer targets was therefore not sensitive to changes in 2020s climate.

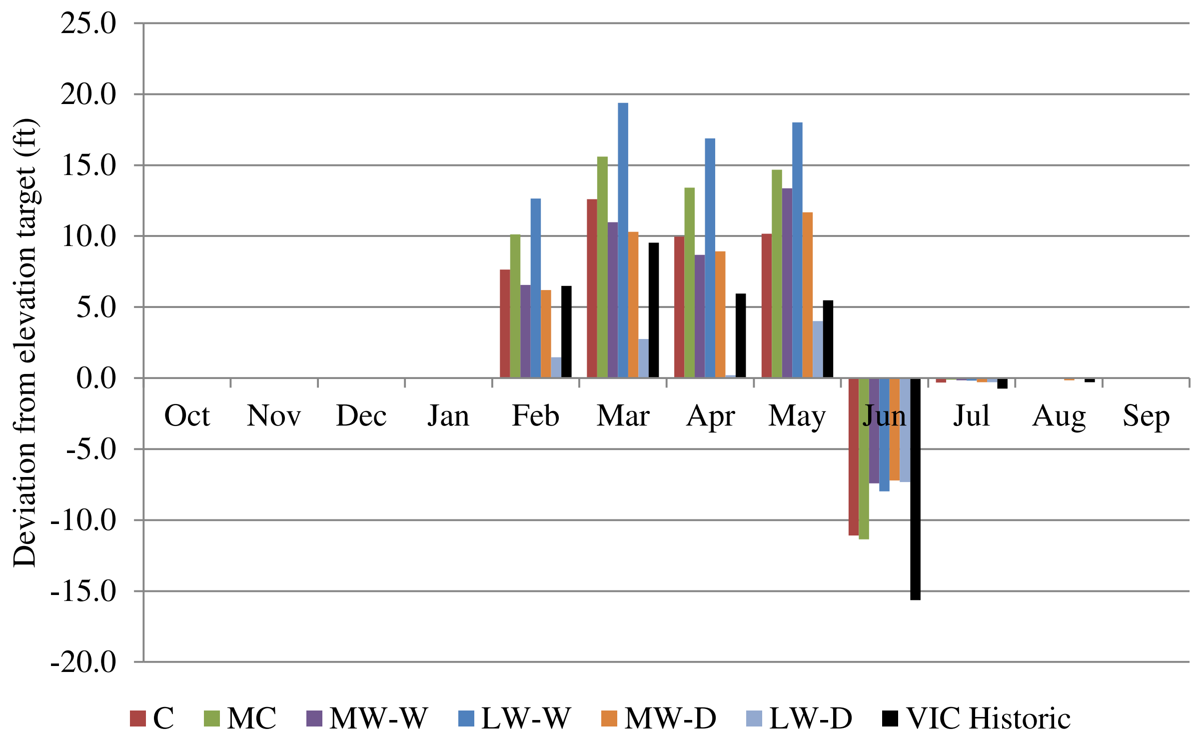

Figure 19. Average deviations from first-of-month target elevations (2020s).

4.2.2 2040s Climate Scenarios

Figure 20 suggests a similar response to that of the 2020s scenarios in terms of deviations from first-of-month target elevations. Fall, early winter, and late summer targets under the climate scenarios were met equally as well as those historically. However, the most important difference is that by July in the 2040s elevations deviate more frequently from targets. Isolating the modeled elevations for the first of July revealed that by the 2040s, achievable elevations deviated much farther from targets than for the 2020s. Historic July 1 elevations were 0.7 ft lower on average for the 1928–1998 period and only deviated by more than 0.5 ft 6 years in the period. Scenarios for the 2020s showed a very similar response and were actually closer to targets—only 0.2 to 0.5 ft lower than target. Under the 2040s scenarios, however, elevations deviated by more than 0.5 ft in 48 to 69 years in the 70-year period, ranging from 2.0 ft above the July 1 target to 4.0 below. This was likely caused by the higher variation in 2040s inflows compared to the 2020s scenarios and suggests that the ability to meet early summer elevations is more sensitive to 2040s conditions than 2020s conditions.

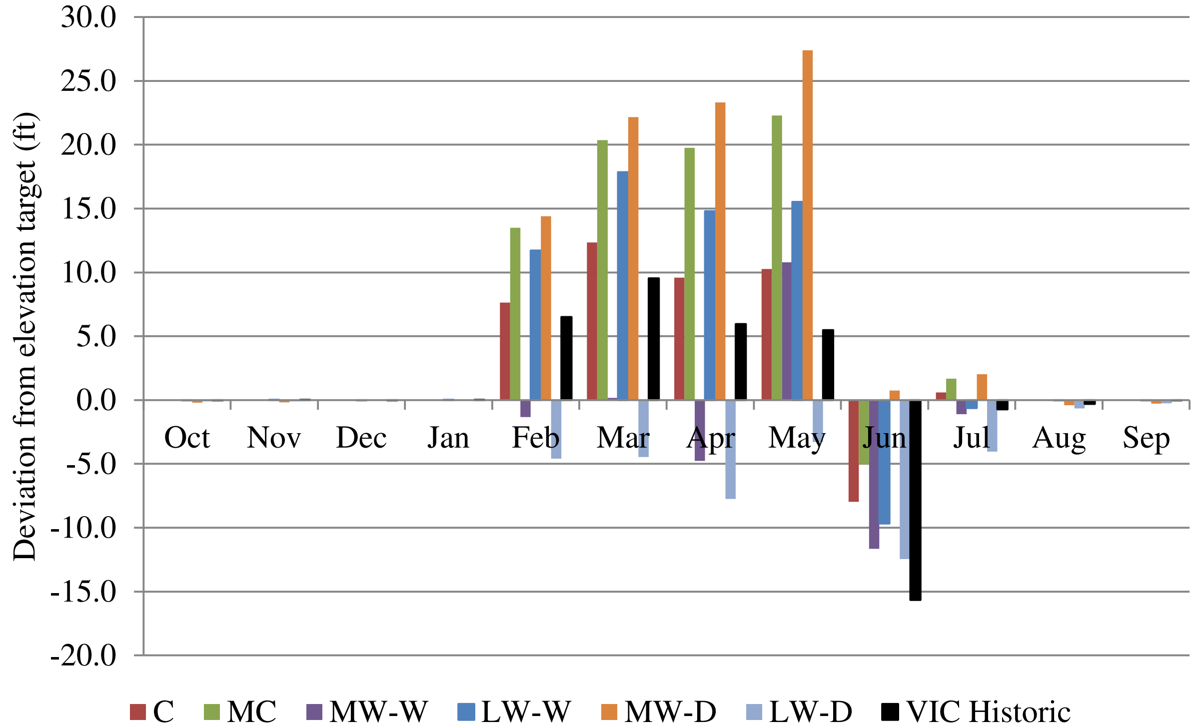

Figure 20. Average deviations from first-of-month target elevations (2040s).

Achieved elevations shown for both the 2020s and 2040s throughout late winter and into May indicate that the reservoir was above targets and thus release was required. However, average June deviations showed that refill was off course as the reservoir was generally below targets. These results suggest that changes in operation may lead to improved reservoir elevations. For example, lower target elevations in late winter would help alleviate over-filling through spring and would likely allow June elevations to be closer to targets. Increased flood risk was shown further by determining the years with the highest required storage volume (Path 5 in Figure 4), which corresponded to years where the expected April–August volume entering the reservoir was above 7.5 Maf. Figure 21 summarizes these occurrences for each climate scenario under both 2020s and 2040s timeframes. With VIC Historic flows, calculated April–August volumes resulted in 21 years in the 1916–2006 period where this volume exceeded 7.5 Maf (dotted line). Several scenarios indicated this high runoff volume could be seen far more frequently in the future, such as the 2040s MW-W scenario with more than 50 years requiring the highest level of reservoir drawdown.

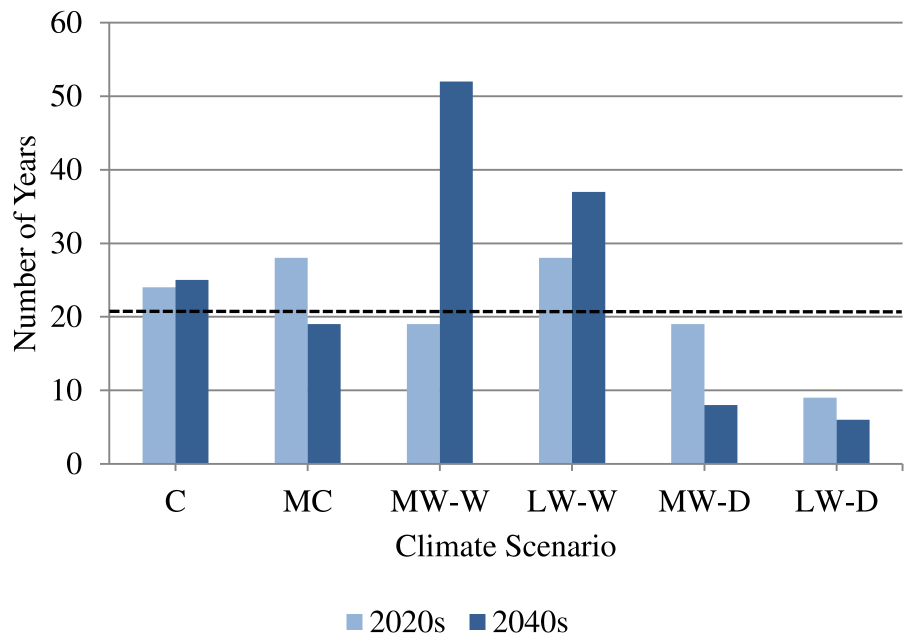

Figure 21. Number of years the forecasted April–August volume of water entering Koocanusa exceeded 7.5 Maf for each climate scenario.

4.3 Hydropower

The approach used to analyze changes in power was to run the ResSim model with the 1928–1998 period inflows under both historic and altered climate conditions to estimate average monthly potential hydropower generation. First, the model was run using VIC historic streamflows to set a baseline, then with streamflows from each of the climate scenarios to compare with the baseline. Power generation was the primary objective in the model, with all flows up to the 25,000 cfs hydraulic capacity of the powerhouse being passed through the powerhouse. Flows exceeding this were diverted through the spillway. The powerhouse generating capacity was set to 600 MW operating at a constant efficiency of 93% for all flowrates.

4.3.1 2020s Climate Scenarios

Results for the 2020s scenarios shown in Figure 22 indicate an average peak generation potential of 420 MW was seen historically in July (December was close at 413 MW), however; this decreased by at least 25 MW under all 2020s scenarios, with the LW-D scenario showing the largest decrease of 76 MW. In addition, average generation potential increased during the March–June period for all scenarios, and for five of six scenarios during December–February. Potential generation appeared to closely follow seasonal changes in inflows under the 2020s scenarios (see Figure 12). Overall, the 2020s scenarios resulted in a 3% increase in average generation during winter months (December–February) and a 7% decrease during summer months (July–September). On a yearly basis, generation increased by an average of nearly 8%.

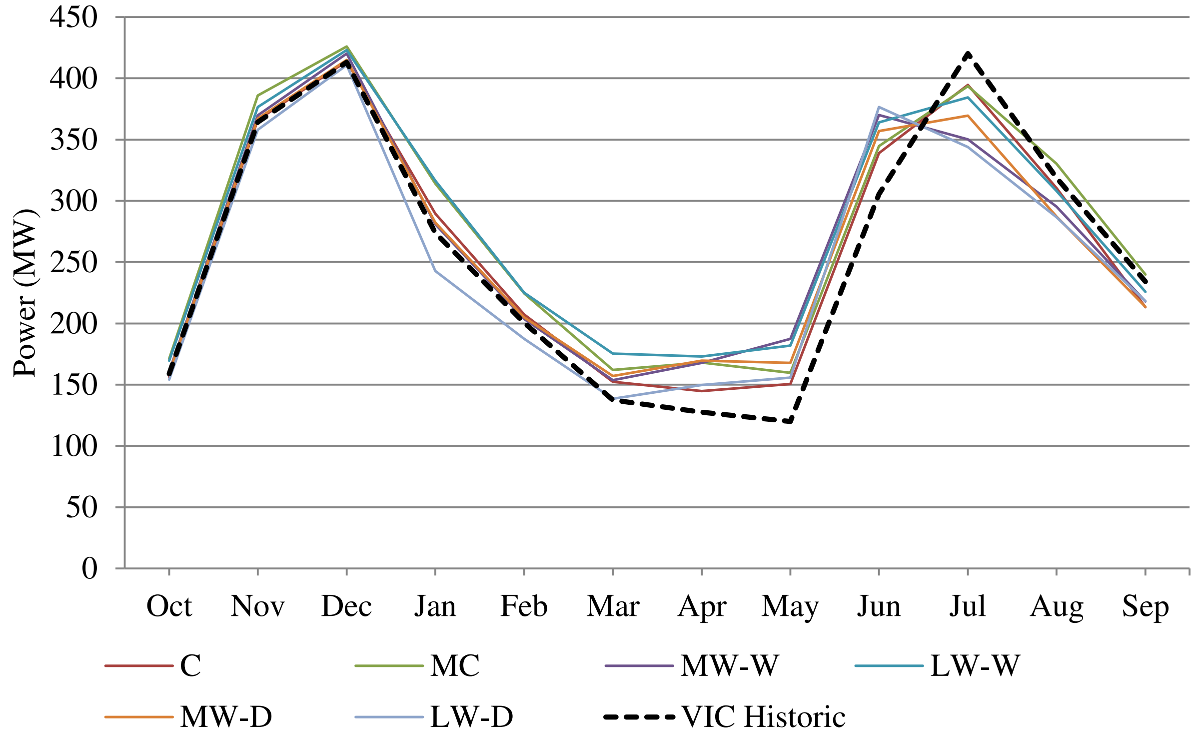

Figure 22. Average monthly power generation (2020s).

4.3.2 2040s Climate Scenarios

Power generation for the 2040s climate scenarios showed a very similar trend to that of the 2020s. Shifts in potential generation generally followed the same pattern of increased generation throughout late winter and early spring with decreases in summer. Results are shown in Figure 23. The key difference in the results for the 2040s scenarios was the greater magnitude of change in power over the 2020s. Much higher variation between the 2040s scenarios is clearly visible. The historic peak in July was shifted to June in four of the six climate scenarios, with the remaining two showing modest differences between June and July values. Decreases in potential generation during July ranged from 40–160 MW for the LW-W and LW-D, respectively. The greatest increase in generation of 170 MW occurred during May for the MW-W scenario, while the same scenario under the 2020s was only 68 MW more than historic. Overall, the 2040s scenarios resulted in a 5% increase in average generation during winter months (December–February) and a 14% decrease during summer months (July–September). On a yearly basis, generation increased by an average of approximately 9%. It is evident the greater variability in 2040s inflows impacted potential hydropower generation accordingly.

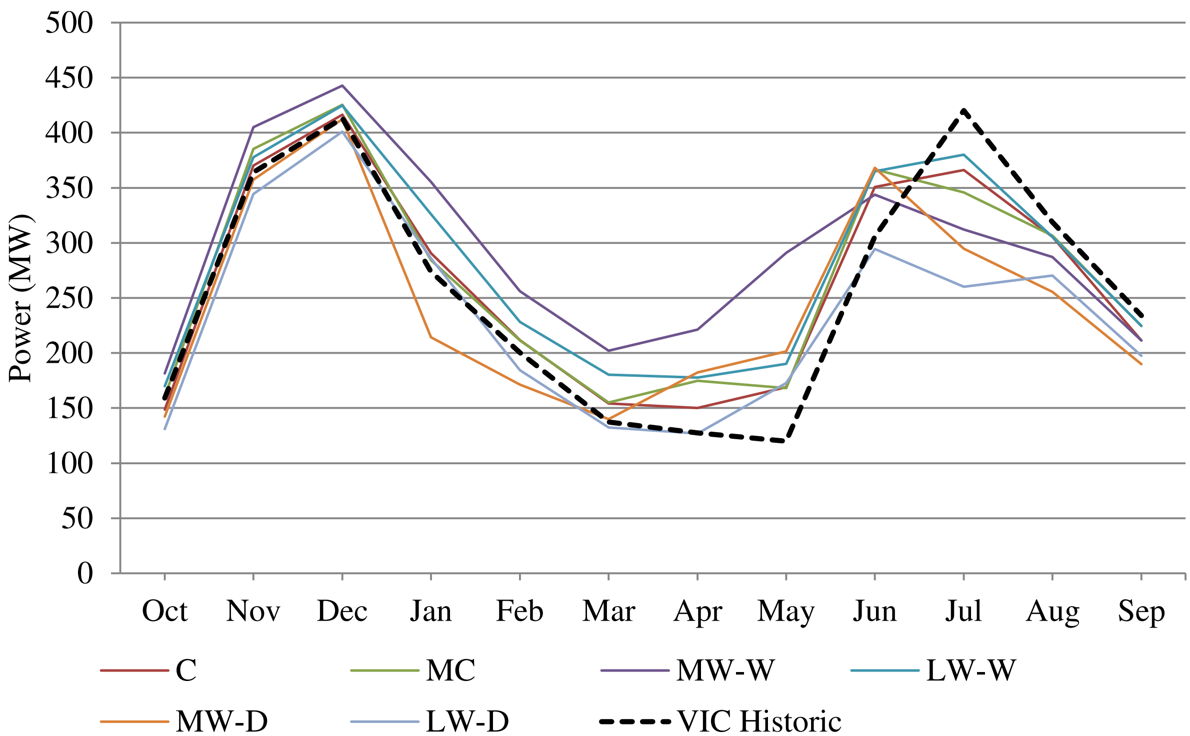

Figure 23. Average monthly power generation (2040s).

For the majority of 2020s and 2040s scenarios, the potential for power generation decreased during summer months and increased throughout spring and winter. Increases during winter months when power demand is high for heating purposes may benefit the Pacific Northwest, but the loss in potential during July and August in combination with the expected increase in summer power demand for air conditioning due to higher average temperatures may prove a challenge.

4.4 Spill

Increased average inflows to Koocanusa under climate change could raise the need for spill during spring. Spills above approximately 1,600 cfs have the potential to harm fish by introducing levels of total dissolved gas (TDG) above the saturation level of 110 percent (Schneider 2003). Excessive spills also increase the flood risk downstream at Kootenay Lake, which is restricted to a maximum elevation of 1,745.32 ft per the 1938 International Joint Commission (IJC) order on Kootenay Lake. Higher May outflows depicted in Figure 15 would result in excessive spill, as shown in Figure 24 for spring and summer of 1997. It was assumed that before spill could occur, the maximum powerhouse hydraulic capacity (25,000 cfs) would be reached first. Adding 25,000 cfs to values depicted in Figure 24 would result in the total outflow from the dam. Of highest interest in this case was the variation in mid-May to mid-June spill rates, the typical beginning of increased outflows for sturgeon spawning (USACE 2005). Spills during this time exceeded historic rates by up to approximately 20,000 cfs. After mid-June however, spill was generally lower than historic for all scenarios. This was likely due to the earlier timing of peak flows and lower summer flows for the 2020s scenarios.

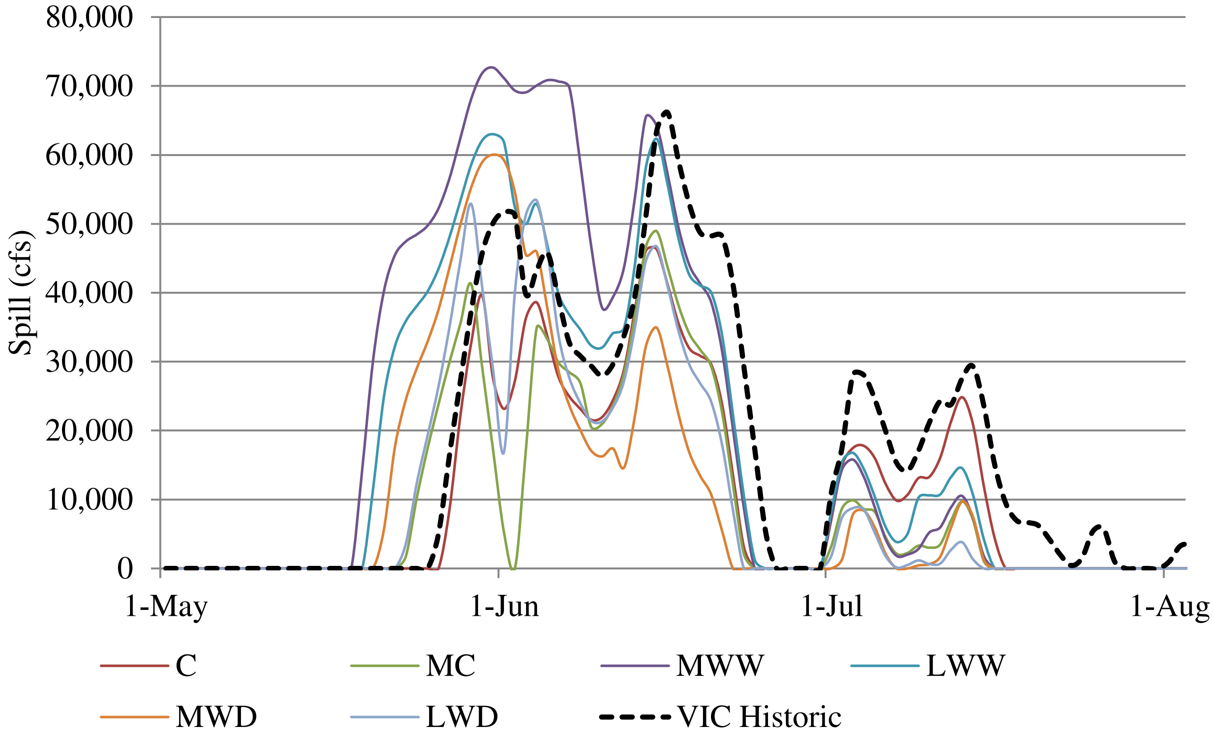

Figure 24. Spill rates for May–August 1997 (2020s).

Observed outflows for Libby never exceeded 55,000 cfs (DART 2013). Since the model allowed spill above this historic maximum, Alternative 2 was designed to test the sensitivity of a maximum outflow restriction on the model's ability to meet reservoir target elevations. Figure 25 shows total outflow from Libby for spring 1997 under 2020s conditions, with the 55,000 cfs maximum outflow restriction.

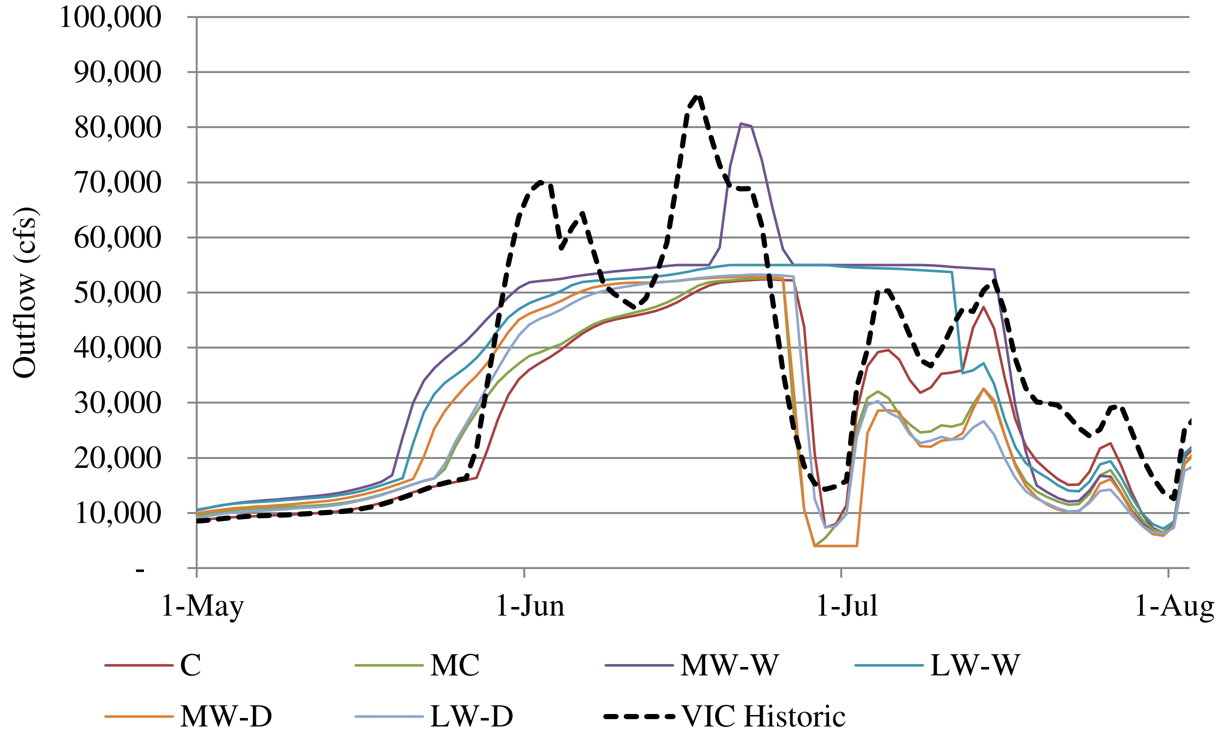

Figure 25. Outflow under Alternative 2 for May–August 1997 (2020s).

The maximum outflow capacity was adhered to for all but 5 days in 1997, which occurred under the MW-W climate scenario with a peak outflow of over 80,000 cfs in late-June. This exceedence occurred because the reservoir surpassed the maximum pool elevation (2,459 ft) by nearly 3 ft and water was released at rates above 55,000 cfs attempting to return the reservoir to maximum pool. The result of the restriction was that June and July first-of-month target elevations were exceeded by as much as 20 ft more than historic under the MW-W scenario, as shown in Figure 26. This implies that restricting the maximum outflow to 55,000 cfs generally did not affect Libby's ability to meet target elevations any more than under Alternative 1 conditions. In conditions like those in the 1997 water year, target elevations were exceeded far more often. A reasonable solution to this issue is to begin drawdown of the reservoir earlier in spring.

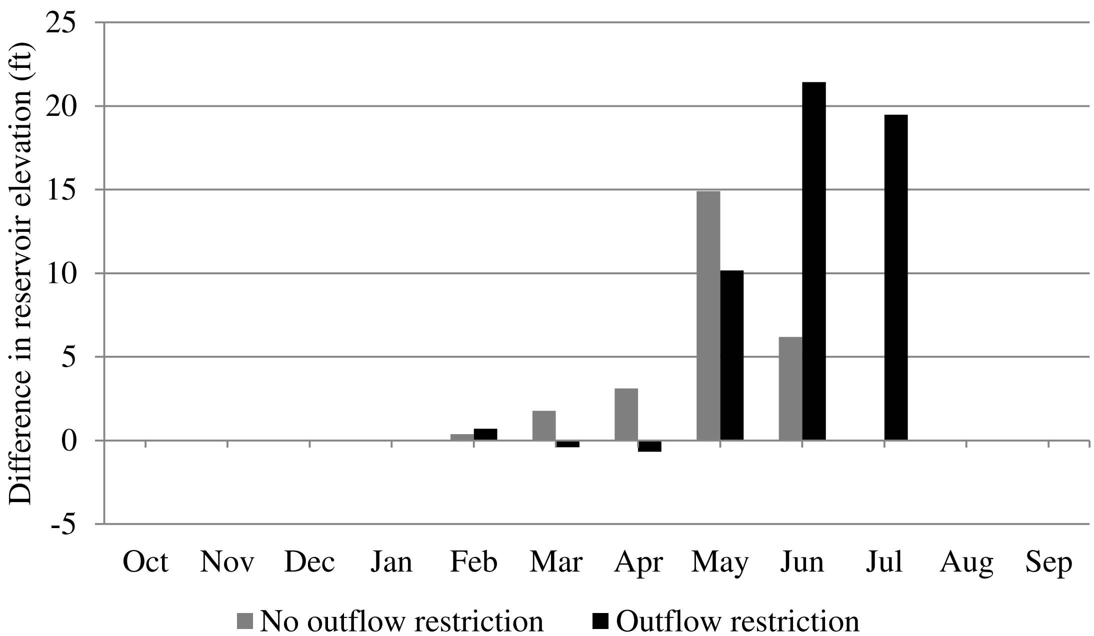

Figure 26. Difference in modeled elevations between MW-W scenario (2020s) and VIC Historic for water year 1997.

A solution to this issue could be to raise the maximum pool elevation of Koocanusa by one foot from 2,459 ft to 2,460 ft, adding approximately 32,000 af of storage space. This idea has been considered in the past to prevent flooding downstream at Kootenay Lake (USACE 2012) and was thus used in this study to determine if the same approach could be used under climate change to help minimize outflows during peak runoff. Required spill for May–August 1997 under 2020s climate conditions was determined using the original methodology described in Chapter 3.5 for Alternative 3. In general, decreased spill was required throughout June relative to historic when increasing the maximum pool to 2,460 ft, as depicted in Figure 27. Spill in May was largely unaffected with the additional storage space. June spill was sometimes significantly reduced, even eliminated at times. By July, however, spill under Alternative 3 was higher for each scenario compared to the corresponding scenario with the original maximum pool. For the purpose of protecting Kootenay Lake from flooding, increasing the maximum pool elevation of Koocanusa to 2,460 ft would likely help.

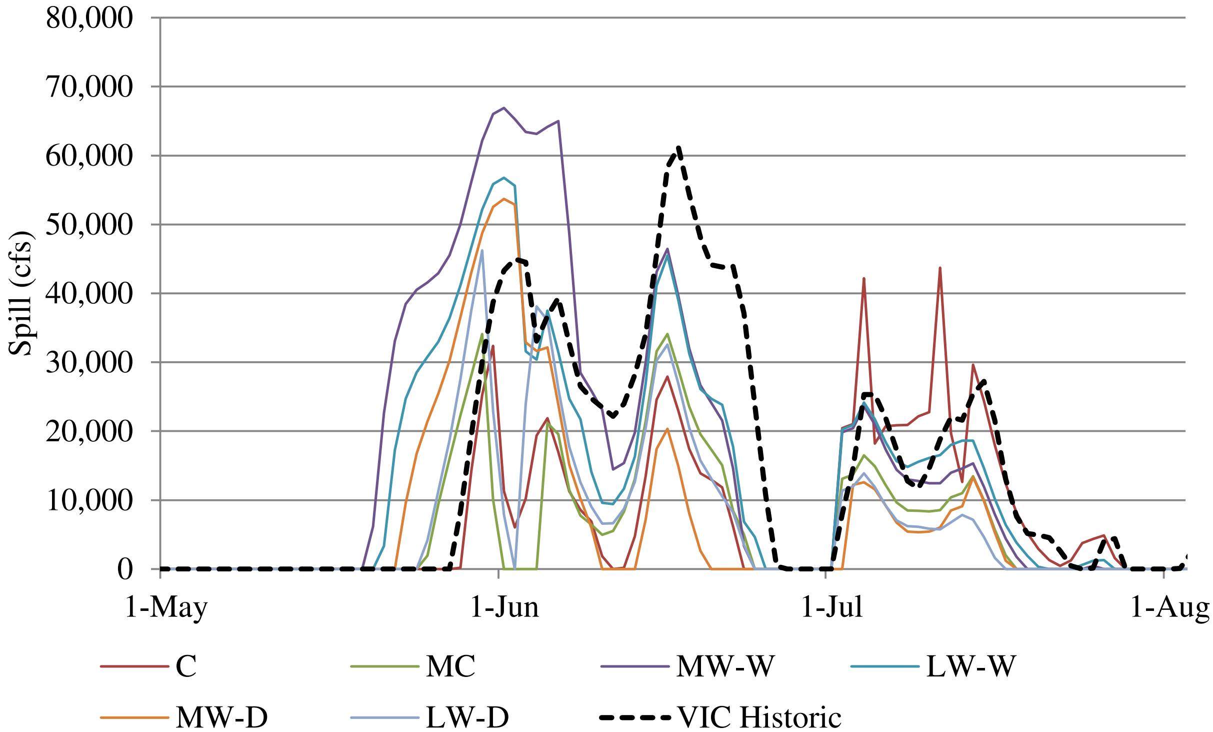

Figure 27. Spill rates for May–August 1997 (2020s) with 2,460 ft. maximum pool elevation.

4.5 Flow Augmentation

In their 2012 Water Management Plan, BPA et al. (2011) stipulated a minimum project outflow for Libby of 4,000 cfs. Further, the plan included ramping rates as proposed in the USFWS 2006 BiOp. Both of these criteria are intended to protect fish (namely white sturgeon) and other aquatic species against adverse impacts from operations at Libby and were incorporated into the ResSim model. The BiOp also introduced the idea of additional release for sturgeon flow augmentation on the order of 35,000 cfs for short periods of time (e.g. one week). Although it has been shown that sturgeon spawning is more dependent on water temperature than flow magnitude, lower temperatures that are ideal for spawning usually correlate with higher flows (Paragamian and Wakkinen 2011). Alternative 4 as described in Chapter 3.5 used a 10,000 cfs minimum discharge during the months of April, May and June under the 2020s climate scenarios to test the sensitivity of a similar requirement on reservoir storage and refill. All other reservoir constraints and operations from Alternative 1 remained the same. Figure 28 shows the results for this alternative. When compared directly to results in Figure 19, which used the 4,000 cfs outflow requirement, significant variations in first-of-month elevations occurred. For example, during April and May, achieved elevations were closer to targets by around 5 ft for most scenarios with the 10,000 cfs outflow requirement. During the refill period in June, however, the climate scenarios resulted in missing target elevations by an additional 7–10 ft compared to Alternative 1 operations. July and August elevations were never more than 1 ft below targets under Alternative 1, but with the increased outflow requirement elevations during these months were approximately 1–3 ft below targets. A 10,000 cfs outflow requirement clearly affected the model's ability to meet summer targets due to the higher outflows required during the refill period. This does not imply, however, that higher outflows during these months for shorter time periods (e.g. one week) would affect refill in the same way. Alternative 4 does, however, show that increased outflow requirements lasting for more than a couple weeks, for instance, could negatively impact refill objectives of the reservoir.

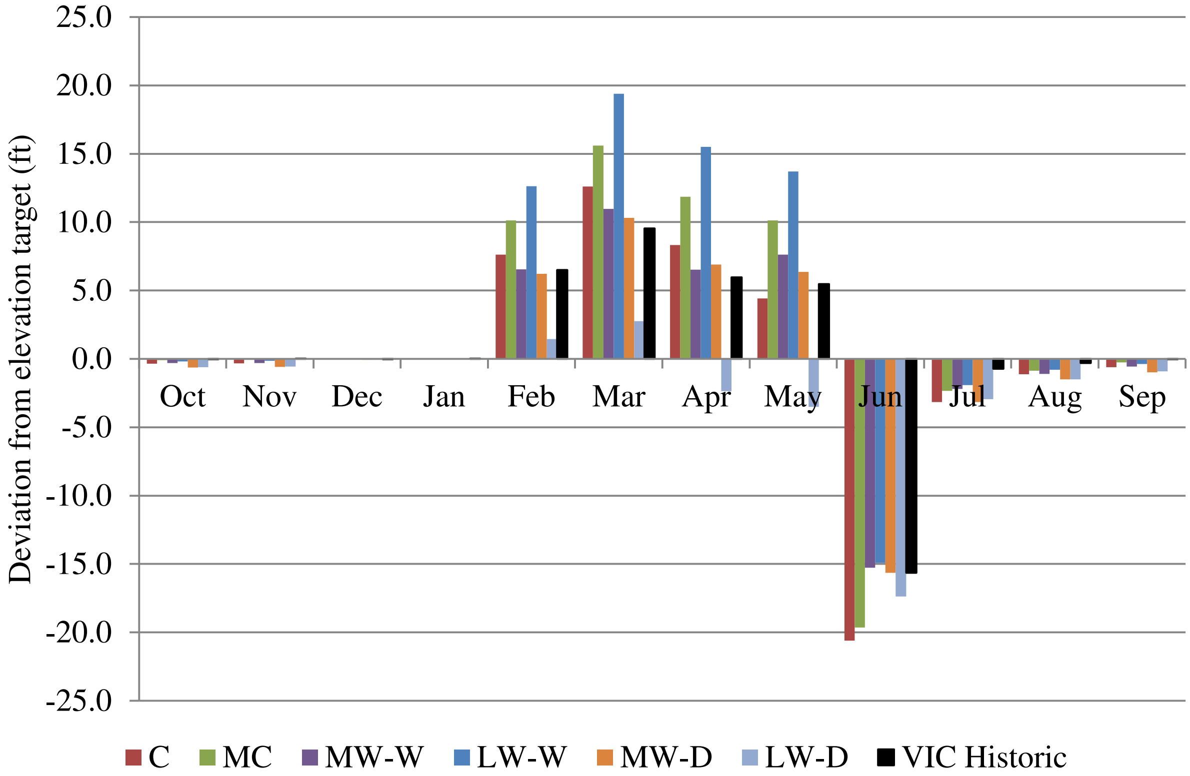

Figure 28. Average deviations from first-of-month target elevations (2020s) with increased outflow requirement.

4.6 Columbia River Treaty

Climate change impacts on streamflow timing and availability and the subsequent effect on reservoir objectives as discussed in this chapter suggest future water agreements must consider these changes to be effective at managing water resources. Given the lifespan of typical treaties, future changes in climate come into play and can significantly impact the provisions of such an agreement.

As one of the reservoirs that must be effectively used before extra storage will be made available in Canada (USACE et al. 2010b), Libby's operations could be directly impacted by a switch to called-upon flood control. Results in Chapter 4.1 showed that spring flows in particular are likely to increase. With this in mind, the Corps may have to operate Libby to a lower FCC during this time if the goal is to avoid the use of called-upon storage. To determine if the additional volume expected in spring under climate change would necessitate the use of storage space in Canadian reservoirs, a worst case scenario was examined using the climate change scenarios. The highest instance of April–August runoff volume for the 2020s was approximately 11.9 Maf under the MW-W scenario in 1997, a total of 340,000 af more than historic. Figure 29 shows this additional volume resulted in an elevation 15 ft higher than that with VIC Historic flows on May 1. The highest instance of April–August runoff volume for the 2040s was also the MW-W scenario during 1997 with approximately 13.6 Maf, or 2.0 Maf more than historic. These inflows caused more of an issue, resulting in a May 1 elevation 45 ft higher than the elevation achieved using VIC Historic flows. Referring back to Figure 15 and Figure 18, these events required outflows by the end of May far higher in magnitude than historically. Had evacuation of the reservoir occurred sooner in spring, target elevations may not have been exceeded to this degree and outflows would have been significantly lower.

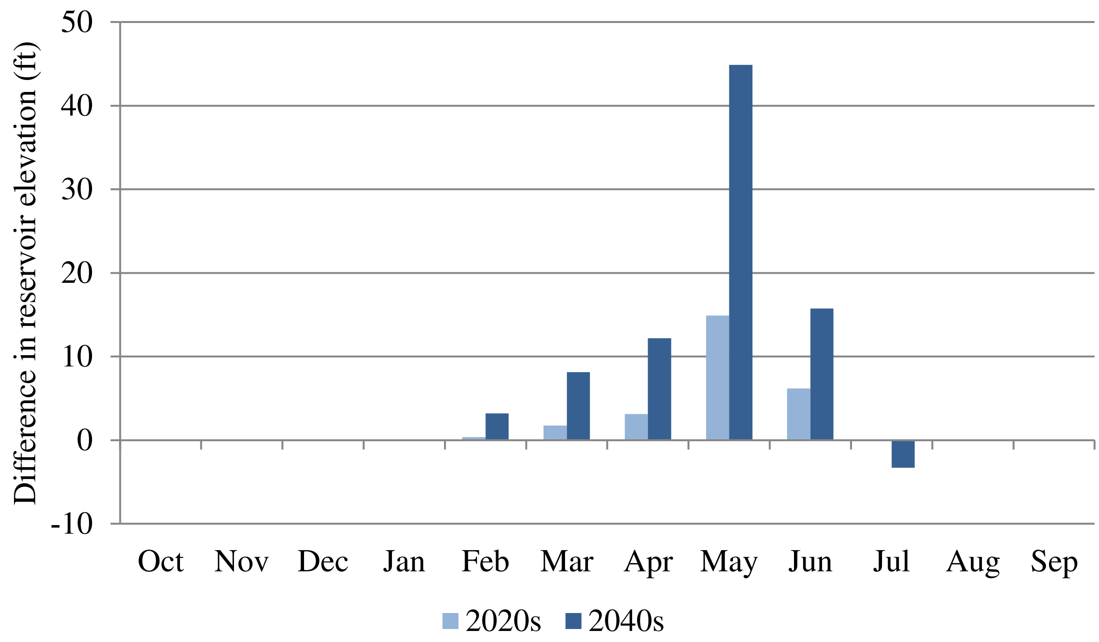

Figure 29. Difference in modeled elevations between MW-W scenario (2020s) and VIC Historic for water year 1997

An important consideration regarding the future of the treaty is that perspectives on the definition of "effective use" differ widely between the United States and Canadian Entities. The Corps has identified 8 U.S. projects that could be used to adequately reduce flood risk: Libby, Hungry Horse, Dworshak, Brownlee, Kerr, Albeni Falls, Grand Coulee, and John Day (USACE and BPA 2013). BC Hydro, however, argues that all U.S. reservoirs upstream of The Dalles Dam must be used "regardless of its designated use or licensing or the economic cost of using the storage" (BC Hydro 2013). Further, flow at The Dalles must exceed 600,000 cfs before the U.S may call upon Canada for storage, a magnitude the Corps has determined commences serious damage near Portland (USACE et al. 2010b). Without the option to use Canadian storage in absence of the treaty, extreme situations like those shown in Figure 29 (e.g. May during the 2040s) imply changes would have to be made to Libby's operations.

Chapter 5: Conclusions and Recommendations

5.1 Conclusions

Using Libby Dam as a specific case study, this work has shown how climate change could potentially affect reservoir operations in the future. Shifts in the timing and magnitude of peak streamflows directly impact reservoir outflows, storage, and potential hydropower generation as a result. In this study, climate change scenarios for the 2020s and 2040s were incorporated into a reservoir simulation model to quantify the changes in reservoir outflows, flood storage, potential hydropower generation, and other operational objectives. The sensitivity of the model to alternatives designed for addressing certain operational considerations was also examined. For the final objective, environmental and social consequences resulting from changes in climate were explored. This chapter provides concluding remarks and recommendations for future work based on these original objectives.

HEC-ResSim was used to model Libby's operation under the first objective outlined in the scope (Chapter 1.3). ResSim was chosen due in part to its ease-of-use and widespread acceptance amongst water managers and planners. It also has the ability to easily simulate multiple scenarios in a short period of time, making the program not only useful for this particular study, but also for any future studies intended to expand upon this work. Information on Libby and Lake Koocanusa was obtained from various sources to replicate the physical and operational characteristics of the facility. The most important operations needed were rule curves, the monthly target reservoir elevations needed to successfully meet operational objectives.

The second objective, determining the changes in future reservoir storage and potential hydropower generation, was met by using the ResSim model to simulate both VIC modeled historic conditions and 6 future climate scenarios for 2 time periods. Results showed that flood control and refill potential could be significantly impacted. Exceedance of reservoir elevation targets means outflows would have to increase to return the reservoir to its intended level. Further, high reservoir levels could also indicate an increase in flood potential both locally and downstream, especially during the spring freshet when high volumes of water are still entering the reservoir. For hydropower, a shift in average potential generation was observed under all climate scenarios. Historically, peak generation capability occurred during July, but shifted to December under the climate scenarios due to increases in winter runoff and decreases in summer runoff. Spring months saw the highest increases in generation potential. These changes were attributed to the earlier timing of spring runoff due to warmer average temperatures. Combined with an expected decrease in winter power demand and increase during summer, these results imply that operational changes may be warranted to maintain Libby's power generation role.

The third objective was to examine the sensitivity of the dam's ability to meet objectives using specific operational alternatives during critical periods such as dry or wet years during the 2020s timeframe. For example, the second alternative utilized a 55,000 cfs maximum outflow restriction during the wet year of 1997 under 2020s conditions. The restriction was for the most part adhered to and generally did not hinder Libby's ability to meet elevation targets, except for one 5-day instance under the MW-W scenario. During this event, the dam was actually overtopped and outflows exceeded 80,000 cfs. Events like this could cause serious damage both locally and downstream on the Kootenay and Columbia rivers. Modified rule curves that allow for earlier drawdown of Koocanusa may help alleviate situations like this. Earlier drawdown, however, puts reservoir refill at a higher risk so this must also be considered. The third alternative, raising the maximum allowable reservoir elevation by 1 ft, was successful in reducing outflows during spring. This also resulted in increased outflows during July while still maintaining full pool. These outflows could also be used to generate additional hydropower, which would benefit the expected increase in summer power demand. Finally, the fourth alternative established a 10,000 cfs outflow minimum that caused further deviation away from June 1 target elevations. The alternative also resulted in decreased reservoir elevations (closer to targets) throughout early spring compared to Alternative 1 operations. However, because July 1 elevations were lower than targets for all scenarios, this alternative may not be preferred if full pool on this date remains a primary objective.

The fourth objective, exploring environmental and social impacts of climate change, was approached in a more qualitative way for the Libby case study. Many outcomes related to the second and third objectives can suggest considerable impacts on other reservoir objectives like ecosystem function, Native rights, recreation and the CRT. Although releases are made during spring for sturgeon spawning, excessive spill can actually harm these fish and other aquatic species. For example, the earlier peak inflows that resulted in the need for high spills in early spring have the potential to elevate TDG concentrations beyond the allowable level. This study did not incorporate a spill limit based on meeting these levels, but TDG remains a concern in daily operation. Flexibility would therefore be required so operators could choose precisely when spill would benefit aquatic habitat, but not hinder other objectives like refill capability. Refill capability could also be decreased by earlier drawdown of Koocanusa in anticipation of a high runoff year, as was previously mentioned. Though this procedure could help prevent spring flooding, it can also temporarily expose Native burial grounds along the reservoir, posing many cultural issues, not to mention grave-robbing. Decreased refill potential also can impact recreation on the reservoir, especially when full pool is not achieved by summer. A full reservoir means the maximum area for fishers and other water users and fully accessible boat ramps. Extra release in the future for late-summer hydropower generation is one way these objectives could be impacted. Finally, in the context of the CRT, changes in water timing and availability point to the need for adapted policies to maintain system objectives. Further, changes to the treaty such as the shift to called-upon flood control mean Libby will need to change operations, especially if there is no option of using Canadian storage until all U.S. storage is utilized beforehand.

This work has shown that with a given range of projected future climate conditions, impacts on reservoir objectives are foreseeable, but they can likely be alleviated by minor changes in management and operations. Uncertainties exist in all aspects of the modeling framework, but they can be partially addressed by more accurate streamflow forecasts. Certain events, such as the 1977 drought year (Figure 14), were not accurately portrayed by the VIC model. Forecasts need to capture extreme events so effects on flood control and hydropower generation can be examined in the most accurate way. Until then, flexibility is required to mitigate the changes in streamflow timing and availability so that reservoir system objectives can be met.

5.2 Recommendations for Future Work

Future studies related to this topic should expand upon the reservoir model, incorporate newer and more accurate depictions of future climate in the CRB, and examine CRT options as they are discussed. Additional areas of research include:

1. As it becomes available, make use of hydrologic data downscaled to the watershed level that more accurately captures extreme events like flood and drought conditions.
2. Add an elevation constraint at Kootenay Lake as outlined by the IJC Order on Kootenay Lake. This will dictate outflows from Libby so that flooding is prevented downstream.
3. Extend the reservoir model to include other downstream facilities and examine impacts on a more system-wide scale.

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