A DECISION SUPPORT SYSTEM FOR REAL-TIME HYDROPOWER SCHEDULING IN A COMPETITIVE POWER MARKET ENVIRONMENT

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ABSTRACT

The electricity supply market is rapidly changing from a monopolistic to a competitive environment. Being able to operate their system of reservoirs and generating facilities to get maximum benefits out of existing assets and resources is important to the British Columbia Hydro Authority (B.C. Hydro). A decision support system has been developed to help B.C. Hydro operate their system in an optimal way. The system is operational and is one of the tools that are currently used by the B.C. Hydro system operations engineers to determine optimal schedules that meet the hourly domestic load and also maximize the value B.C. Hydro obtains from spot transactions in the Western U.S. and Alberta electricity markets.

This dissertation describes the development and implementation of the decision support system in production mode. The decision support system consists of six components: the input data preparation routines, the graphical user interface (GUI), the communication protocols, the hydraulic simulation model, the optimization model, and the results display software.

A major part of this work involved the development and implementation of a practical and detailed large-scale optimization model that determines the optimal tradeoff between the long-term value of water and the returns from spot trading transactions in real-time operations. The postmortem-testing phase showed that the gains in value from using the model accounted for 0.25% to 1.0% of the revenues obtained. The financial returns from using the decision support system greatly outweigh the costs of building it. Other benefits are the savings in the time needed to prepare the generation and trading schedules. The system operations engineers now can use the time saved to focus on other important aspects of their job. The operators are currently experimenting with the system in production mode, and are gradually gaining confidence that the advice it provides is accurate, reliable and sensible. The main lesson learned from developing and implementing the system was that there is no alternative to working very closely with the intended end-users of the system, and with the people who have deep knowledge, experience and understanding of how the system is and should be operated.

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CHAPTER 1
INTRODUCTION

1.1 BACKGROUND

Since the invention of electricity in the last century, man has been trying to develop new sources of electrical energy and to enhance the methods of operating existing ones. In modern societies, electrical energy forms the backbone of almost all activities, and the key role that it plays in today's society cannot be overemphasized. The increasing importance of electricity has required the development of one of the most complicated systems ever to be built by humans. Management of such complex systems has traditionally required creation of large organizations in the form of government regulated utilities. A utility's power system could typically consist of hydroelectric facilities on one or more rivers, fossil and nuclear thermal power stations, and export and import ties to neighboring utilities. All of these facilities are interconnected electrically through the electric transmission system.

The large investments in and rising costs of operating power production facilities have highlighted the need for increased technical and economic efficiency in the electricity production sector. Planning and management of such systems in real life situations is a complex and cumbersome task and it requires highly specialized technical expertise in many fields. Traditionally, the greatest gains have been realized from improving the technical and the economic efficiency of the electric system. Improvements in technical efficiency include enhancements to the performance of generation facilities, while improvements in the economic efficiency includes long-range planning for system expansion, least-cost operation by optimizing long-term and short-term system operation, and providing better financial management of electric utilities. These measures on the "supply side" have been tackled with varying degree of success, usually by engineers and other professionals using technically and financially oriented methods. Other efforts focused attention on the objectives of "demand side" management to reduce consumption of electricity and to avoid unnecessary investments to meet the growing demand for electricity, particularly during peak demand periods.

Recent changes in the electric industry have been brewing since the shock of OPEC's oil embargo in 1973, where a shift towards more self-reliance on energy resources was set as a national goal in the U.S. and in many other industrialized countries around the world. Traditionally, generation, transmission and distribution, and marketing of electricity were carried out by one monopolistic, vertically integrated utility serving a geographic region. Electricity interchanges were made among the few major utilities. However, as predicted by Schweppe in 1978 (Schweppe, 1978), the energy marketplace is rapidly evolving towards a competitive market structure. Under this emerging structure many major players are selling and buying electric energy in the spot and in the forward market place at the wholesale level. It is also predicted that soon, electric energy will be sold competitively at the retail level, initially to large industries, municipalities, and large commercial customers, and eventually to residential customers. The future of the electric power industry is uncertain. Some visionaries (Amory Lovins) are predicting the demise of the hierarchical monopolies, who currently command the electric power industry, to give way for new technologies and entrepreneurial actors who could reconfigure the industry, as was originally envisioned a century ago by Thomas Edison: a robust set of technologically advanced, decentralized, interconnected power plants (Smeloff et al., 1997). On the other side, others are predicting the concentration of generating facilities in the hands of mega-generators, controlling a high percentage of the total generating capacity (Weiner et. al., 1997). Only the future will tell how the industry will evolve.

What does this have to do with the problem discussed in this thesis? A great deal. In the extreme case, many of the currently used hydroelectric generation scheduling methods will need to be rethought and probably drastically revised as more emphasis will be placed on efficient and economic operation of generation facilities. It is believed that the use of principles of technical efficiency as well as market-oriented methodologies will become more crucial to the survival of electric utilities. Current planning techniques for establishing hydroelectric generation schedules are really based on the assumption of a single utility serving the electric energy needs of its own customers at minimum cost. Many utilities around the world, with a mix of hydroelectric and thermal generation facilities, value hydropower on the basis of savings in thermal fuels that result from its use. This is to say that the cost of generation is taken into account rather than the product's market value. In financial market terminology, this is defined as a mark-to-cost rather than mark-to-market valuation. As pointed out by Pilipovic, the currently used models are excellent to understand the characteristics of the cost function for a particular utility. This cost function enables utilities to arrive at the future expected costs for their products and the factors that contribute to the distribution of these costs. Ideally, in a deregulated environment, both the cost function and the value of the product at the marketplace should determine the producer's product value (Pilipovic, 1998). In a world of competition and open access, it is not quite clear yet on how to optimally plan hydroelectric generation schedules in both the long-term and short-term, to take advantage of the new market structure, all within the physical, regulatory, and operational constraints imposed on a particular system. In operating a complex hydroelectric system in a competitive market the operational as well as the financial risks will be high. Decision-makers and operators unarmed with rigorous analysis tools and techniques could cause their organization to pay dearly for their decisions.

This thesis contains the results of an applied research project, supported by British Columbia Hydro Power Authority (B.C. Hydro) on the development and implementation of a decision support system to aid B.C. Hydro's operating staff in directing the short-term operations of the hydroelectric generating facilities they manage and to help them to decide on the potential trading schedules they are willing to commit to, while respecting the regulatory, physical and operational constraints imposed on their system.

The decision support system is operational and is one of the tools that are currently used by the B.C. Hydro system operation engineers to determine the optimal schedules that meet the hourly domestic load and that maximize the value obtained for B.C. Hydro resources from spot transactions in the Western U.S. and Alberta energy markets. The optimal hydro scheduling problem for B.C. Hydro, which is the third largest power utility in Canada is formulated as a large-scale linear programming algorithm and is solved using an advanced commercially available algebraic modeling language and a linear programming package. The decision support system has been designed and implemented to be user-friendly, flexible, dynamic, and a fast real time operational tool that accurately portrays the complex nature of the optimization problem. It has been developed and successfully implemented through extensive interaction with B.C. Hydro's system operations engineers. The system consists of five major components: the Graphical User Interface (GUI), the Communication Protocols, the Simulation model, the Optimization model, and the Results-display software. Aside from the detailed representation of more than twenty hydro generating stations and the system of reservoirs, the optimization model incorporates market information on the Alberta Power Pool and the U.S. markets, and tie line transfer capabilities. The bulk of work in this research project was carried out by the author with some programming and data collection help from other graduate and undergraduate students at the University of British Columbia (UBC) and at B.C. Hydro in Vancouver, Canada.

1.2 GOAL, OBJECTIVES AND STUDY APPROACH

The goal of this thesis is to devise, develop and implement a decision support system to assist B.C. Hydro's Power Supply operations engineers in making good operational and trading decisions for their system.

Several objectives were set out for this research effort. The first objective was to develop an understanding of hydroelectric system operations. This was achieved through extensive literature review and study of the decision-making environment at BC Hydro and at other similar hydroelectric power utilities. The literature review focused on the historic development of generation scheduling methods and on those methods that are currently used by hydroelectric power utilities throughout the world. The second objective involved assessment of the potential of available operations research methods to solve the hydroelectric scheduling problem. Linear programming was as the most practical and efficient technique. The third objective involved formulation of the hydroelectric scheduling problem as a linear programming model and testing its potential to solve hydroelectric scheduling problems. This was achieved through extensive interactions with experts on the B.C. Hydro system and by working very closely with the actual B.C. Hydro generation system operators. The fourth objective involved testing and implementing the hydroelectric scheduling model in production mode. This was achieved through the development of a decision support system that makes the model user-friendly and easy to use in production mode. It also involved screening and compilation of the necessary data, training the system users on its main features and capabilities, and debugging and modifying the model and the decision support system to accommodate user's requests and suggestions.

The optimal operation of hydroelectric generating systems can be divided into several computationally manageable levels. Each level provides answers to a different aspect of the total problem. The different levels that can be distinguished are as follows:

1. Strategic, long-term hydroelectric operations planning, where hydro resource utilization and trade opportunities are optimized over monthly time steps for 1-4 years.
2. Strategic and tactical medium-term hydroelectric operations planning, where hydro resource utilization and trade opportunities are optimized over weekly time steps for 1 year.
3. Tactical short-term operations planning, where hydro resource utilization and trade opportunities are optimized over daily or hourly time steps for one week.

4. Real-time hydroelectric operations planning, where hydro resource utilization and trade opportunities are optimized over hourly time steps for one day.
5. Real-time economic dispatch, where loading of hydro resource utilization and possibly trade opportunities are optimized within the hour. This is essentially a static optimization procedure requiring re-optimization at 10 minutes, or shorter time intervals.

This thesis concerns the solution of levels 3 and 4 above and in particular the hourly short-term optimization modeling aspects. Up until the development of the decision support system reported on in this thesis, the methods used by B.C. Hydro (and by the majority of utilities all over the world) to deal with the tactical short-term and real-time operations planning levels, were predominantly heuristic. These methods are based on single plant optimization using rules-of-thumb (mental) procedures for loading plants and units. The heuristic methods, unfortunately, do not ensure that optimal, or near optimal, solutions will be produced.

The research work presented in this thesis considers application of mathematical programming methods to the short-term operation planning of hydroelectric generating systems in a competitive power market environment. The research is particularly concerned with the practical applicability and implementation of the proposed method to large-scale hydroelectric generating systems, with a small thermal component. Previous literature dealt mainly with purely thermal, or systems with a small hydro component. The thesis build on the work of other researchers (e.g., Section 2.2.1), and it also describes the factors that need to be taken into consideration in order to develop methods for scheduling hydroelectric facilities in real life situations.

1.3 ORGANIZATION OF THE THESIS

The thesis is organized into seven chapters. Chapter 2 reviews the literature on hydroelectric generation scheduling techniques, with an emphasis on practical modeling and on the optimization techniques that are used by utilities in the industry today. Chapter 3 describes the B.C. Hydro electric system, its historic development and gives a summary of the generating facilities in current operation. It also briefly discusses the forces driving the change into the new market structure and how B.C. Hydro is responding to change. The B.C. Hydro decision-making environment is outlined, and a brief description of the methods used in generation operations, operations planning, and electricity trade operations are then discussed. The chapter also presents an overview of the decision-making environment for hydroelectric systems and of the available methods and techniques for decision-making and for decision support systems. Chapter 4 presents the structure of the decision support system and details its main components. The objectives of STOM (the BC Hydro Short Term Optimization Model) are first described. This is followed by the user's functional requirements and the design philosophy of STOM. The main components of STOM are then detailed. This is followed by a brief description of the characteristics and main features of the hydroelectric systems currently modeled in STOM. Then, the mathematical modeling methodology adopted in this study is detailed. Chapter 4 concludes with an outline of STOM's four optimization models.

Chapter 5 describes the solution and the implementation processes adopted in this study. The results of implementing the decision support system are given in Chapter 6. The thesis ends with Chapter 7, which includes an evaluation of the strengths and limitations of the proposed modeling methodology, and the lessons learned from developing and implementing the decision support system. This chapter also gives recommendations for future development of the decision support system and an overall approach to hydroelectric system operation.

The Annexes provides material referred to in the thesis. Annex A describes the general algorithm of the hydraulic simulator program. Annex B lists the "To Do Checklist to Run the Short Term Optimization Model". Annex C lists the short-term optimization model software programs, Annex D the main features of the graphical user interface. Annex E describes the procedure followed to determine the optimal unit commitment. Annex F presents the Results graphic displays, and Annex G describes the main operational features of the hydroelectric systems currently modeled by STOM.

CHAPTER 2
LITERATURE REVIEW

This Chapter reviews the literature on hydroelectric generation scheduling techniques, with an emphasis on practical modeling and on the optimization techniques that are used by utilities in industry today. The first section reviews the historic development of generation scheduling techniques since the start of this century, while the second section reviews the state-of-the-art in the industry. The last section provides a summary of the main findings and presents the factors that prompted the use of linear programming to solve the hydroelectric scheduling problem at hand.

2.1 HISTORIC DEVELOPMENT OF SCHEDULING TECHNIQUES

It can be said that solving the hydroelectric generation scheduling problem with multiple plants that are hydraulically coupled is a formidable task. Generally speaking, hydroelectric generation scheduling problems are more difficult than thermal scheduling problems for several reasons. First, the dynamics and constraints that couple hydroelectric generating plants affect the operation of a reservoir across time. Second, fluctuation in reservoir storage over time has a direct influence on the efficiency of the generating facilities. Third, water levels of reservoirs or water bodies, located downstream of generating facilities also have an influence on the efficiency of the generating facilities. Fourth, operation of a reservoir in a river system could be hydraulically coupled with other reservoirs in the same river system or with neighboring systems, thereby adding to the complexity of the problem. Fifth, reservoir releases could be constrained by an array of physical, regulatory, environmental, and operational factors. Sixth, decisions on water releases from a reservoir in any instance affect future operational decisions, thus leading to the need to consider sequential decision processes. This is particularly true when storage facilities are capable of storing water for several years. From this perspective, the short-term scheduling of reservoir operations for hydroelectric power generation cannot be considered in isolation from the medium-term and long-term planning activities and the literature review in this Chapter reflects this reality.

2.1.1 Early Stages of Development

Due to the importance of the subject, scheduling of generation facilities has received attention since the start of this century. The first references to be published on this subject date back to 1919, when apparently engineers started to pay more close attention to the design and operation of hydroelectric facilities. Noakes and Arismunandar, previously with the Electrical Engineering Department at the University of British Columbia, have provided extensive bibliography on optimal operation of power systems for the period 1919-1959 (Noakes et al., 1962). The majority of methods during this period were concerned with the economic operation of small numbers of generating units with no or little consideration for the dynamics of the problem in terms of changes to decision variables over time. The method that was widely used was the incremental cost method. In this method, generating units in a plant were loaded at the level where the incremental cost of each unit was equal. This method is based on the marginal cost pricing principle advocated by utility economists in the early part of this century, when new welfare economics started to emerge (Hotelling, 1938; Montgomery, 1939). An excellent review on the historic development of the marginal cost pricing principle under welfare economics, and its pros and cons, can be found in the works of Ruggles (Ruggles, 1949; Ruggles, 1950). The concept of marginal cost pricing of electric energy in a competitive market structure is one of the issues that is dealt with in this thesis.

During the early part of this century calculating machines were modest, and operators relied on tables and charts that included the incremental water rate for each unit's increment of generation. A simple and quick iterative procedure was required to adjust the power output of operated units to meet the load to be served. This procedure is simpler if all units were of the same characteristics, but not so otherwise. For that reason extensive tables and charts were developed to make this procedure faster. As technology advanced, analog and digital computers were made available, and the procedure was automated by means of simple computer programs.

As the years went by, the number of hydroelectric facilities grew larger, as did the size of the units and the storage facilities –to satisfy the concept of economies of scale and to hedge against fluctuations in weather patterns. Where it was possible to use water again and again to generate electricity in the same river system, several storage reservoirs and generating plants were installed in series. All of this was taking place when advances in the methods of operations research were simultaneously occurring. For example, soon after Bellman introduced the method of dynamic programming (Bellman, 1957), methods for planning the long-term use of storage water in one hydroelectric system started to emerge (Little, 1955). Others tried to use dynamic programming (DP) for multi-reservoir systems, but they were faced with one of the main limitations of the method: the curse of dimensionality (Bernholtz, 1960; Bernholtz, 1962; Larson et. al., 1963). The solution of DP programs requires that the storage state space be discretized, which leads to an exponential increase in computational effort, with increasing number of reservoirs.

Others relied on water release policies in the form of reservoir operating rules, which are generally formulated in an attempt to satisfy demand for water and other requirements, and provide adequate storage for future water use (Brundenell et al, 1954). Reservoir operating rules define target storage levels for various dates in a year. If a reservoir is below the target storage level, the average outflow rate could be decreased to restore storage to its desired level. Several types of operating rules can be formulated, each reflecting the desired, or required, reservoir releases or storage volumes at any particular time of the year. Some of the rules identify storage targets (called "rule curves") which are passed to system operators to implement the policy they represent. This type of rule could be developed from yield models (Loucks et. al., 1981) using statistical analysis methods. Yield models refer to flows having a relatively high reliability, or probability, of being equaled or exceeded in future periods. Rule curves that specify release policies are derived by considering the required storage levels, as a function of time, which could achieve future outflows with a given reliability level. Associated with the derivation of rule curves is the estimation of the minimum zone, which involves a statistical analysis of inflows to reservoirs in dry years.

The method of rule curves was probably devised as a result of economic research on the problem of inventory control investigated in the 1950's by Kenneth Arrow, one of the leading researchers in the field of economics (Arrow, et al., 1951; see also Arrow et al., 1958). In 1954 Moran introduced the probability theory of dams and storage systems and found a complicated analytical solution that describes the probability distribution of the content of a reservoir as a function of the probability distribution of the inflows and release rules (Moran, 1954). He further extended the theory by considering modification of the release rules, considering different release rules for different months of the year, and obtaining an exact solution for a negative exponential input function that describes the probability distribution of inflows. He further devised a numerical method for obtaining an approximate solution in the case of type 3 Gamma distribution input function (Moran, 1954). Gani, analogously extended the theory of optimal inventory policy (Gani, 1957) and showed that, although simplified, it could be applied to storage reservoirs. But since the problems "form a class of stochastic processes with difficulties of considerable depth," numerical techniques were suggested to provide solutions that were considered adequate in practice. These techniques include Monte Carlo simulation, as described by Gani and Moran (Gani et al., 1955). It should be noted that the Moran theory of storage seeks answers to probabilistic rather than optimization problems, and that one of the basic assumptions of the theory is that inflows to a reservoir are not correlated (Reznicek et al., 1991). Similar methods were investigated by Gessford and Koopmans in the late 1950's (Gessford et al., 1958; Gessford, 1958) to derive a "simple" optimal water utilization policy for a hydroelectric system (or a number of hydroelectric facilities in different river systems). Inflows were considered as independent random variables, and if the probability distribution function for the inflows could be explicitly solved (integrated), the optimal water utilization policy could be determined recursively by dynamic programming. As indicated by Gessford, one of the important characteristics of the optimal policy derived by this method is its theoretical and practical simplicity, which makes its exploration in the future worthwhile for the long and medium-term scheduling problem of reservoir operation.

In a methodology closely related to water release policies, zoning of a reservoir's storage has been used extensively by the Corps of Engineers in the U.S. to study modes of operation for multi-reservoir systems. The concept relies on the preference of the system operator, who provides guiding principles for system operations. For example, during flood situations, the uppermost zone of storage will be utilized to alleviate downstream flood damage. On the other hand, when storage reaches a lower buffer zone, downstream discharges are reduced to provide water for essential needs. The objective of the system operator is to monitor the system behavior, and to try to keep the system of reservoirs in the same zone. In 1976 Sigvaldason introduced a simulation model that is intended to aid in assessing the impacts of alternative policies by penalizing deviations from the operator's prescribed preferences in the form of storage and channel flow zones. The operator's perceived policy for a multiple reservoir system was derived by representing the reservoir system in a "capacitated network" formulation and by deriving the optimal operating policies with the out-of-kilter algorithm (Sigvaldason, 1976). This type of model does not yield the optimal solution to the multi-reservoir, multi-objective decision problem, but is very effective in assessing the impact of different operating policies for reservoir operations. Perhaps the optimal (or near optimal) operating policies could be derived by some kind of reverse modeling and optimization. The methodology could consist of iteratively running the model to optimize the performance of operational policies through variation of the boundaries of the zones and penalty function coefficients.

The end of the 1950's and during the 1960's witnessed a growing interest in the development of hydroelectric operations methodologies. Perhaps the most important contributions to the methods, from the point of view of this thesis, were due to Glimn and Kirchmayer (Glimn et al., 1958) with the General Electric Company in the U.S., and to Stage and Larsson (Stage et al., 1961) with the South Sweden Power Company, and to Lindqvist (Lindqvist, 1962) with the Swedish State Power Board. In these articles, particularly that of Lindqvist, methodologies that consider the long and short-term multistage decision processes were outlined. In essence, the methods assume that a reservoir price curve can be determined iteratively for each time step in the analysis (e.g., daily, weekly or monthly). The problem considered was how to regulate the storage of available water in such a way that, for each possible alternative operation, the sum of the variable costs would be minimized over the long run. At each decision stage, the decision-function, represented by the reservoir price curve, will yield the production level that represents the optimal value for the coming time step. The reservoir price curve represents the expected incremental hydroelectric power value of stored water as a function of the known contents of the reservoir and as a function of time. The methodology assumes that inflows to a reservoir are stochastic. It also assumes that given certain minimum reservoir levels that cannot be violated, the power generator is willing to acquire the power required to meet the demand by either running expensive generation facilities (e.g., thermal units) or by curtailing supply for some customers (or by purchasing, or selling surplus, energy in the competitive market as used in this thesis). It should be noted that deriving reservoirs' price curves is not the concern of this thesis, but the concept of using the reservoir price curve for making short-term operating decisions, for the next planning period, is. Deriving reservoirs' price curves is the subject of long-term and medium-term operations planning models. It should also be noted that a variant of this methodology is extensively used to plan the operation of the Norwegian hydroelectric system, in a competitive market environment.

2.1.2 The Era of Rapid Development

In the 1970s and 1980s, the energy crises caused oil prices to soar and created significant interest in optimizing the operation of hydroelectric systems to save fuel costs (the classic hydrothermal coordination problem). This has resulted in an unprecedented growth in research projects aimed at managing reservoir operations in an optimal manner (Unny et. al., 1982). The main thrust of almost all developed techniques during these two decades focused on problems of coordination between hydroelectric and thermal generating facilities. The goal was to save expensive thermal generation costs by reducing fuel usage. Scientists from different fields of expertise (e.g., engineers, mathematicians, economists, management and operations research scientists) worked on developing sophisticated techniques and methods to solve the optimal long-term and short-term hydrothermal generation scheduling problems. Despite all of this effort, no completely satisfactory solution has yet been obtained, since every problem analyzed was unique and had to be simplified in order to be solved by available techniques and computer technology (Wood et al., 1996).

Towards the end of this era, Yeh conducted an excellent critical review of the state-of-the-art of the available techniques for reservoir operations (Yeh, 1985). He classified the available methods to solve reservoir operations problems (for power generation and other uses) into four major classes:

- Linear programming (LP);
- Dynamic programming (DP);
- Nonlinear programming (NLP); and
- Simulation.

Combinations of the above methods were also in common use.

The review indicated that soon after the techniques were developed, a non-rigorous hierarchical approach was adopted by many users (see the section on real-time operations in Yeh's paper). The hierarchical approach depended on dividing the planning horizon to long, medium and short-term operations models. Information flow between these models formed the link that is believed to yield optimal reservoir system operation. Yeh also noted that linear programming has been one of most widely used methods in water resources management and reservoir operations, particularly for planning as well as real-time operations. He also indicated that the main advantages of using linear programming for real-time operations are the following:

1. The ability to solve problems with a large number of decision variables;
2. The optimal solution is a true optimum;
3. Quick solutions could be determined with no initial feasible starts;
4. Solution techniques have been coded, tested, and are readily available in the market.

Yeh also identified several reasons for the reluctance of real-time reservoir operators to use optimization models for their daily operations. He summarized the reasons as follows (Yeh 1985, p. 1814):

> "1. Most of the reservoir operators have not been directly involved in the development of the computer model and thus are not entirely comfortable in using the model, particularly under the situation where modifications have to be made in the model to respond to changes encountered in the day to day operation,
>
> 2. Most of the published papers deal with simplified reservoir systems and are difficult to adapt for use in real time systems. In addition, most of the published research results are poorly documented from the practical use point of view,
>
> 3. There are institutional constraints that impede user research interactions."

One of the aims of the work described in this thesis, is to overcome the reluctance of operators to use the optimization model developed. One final note on Yeh's review is in order here. It was noted that the majority of the reviewed literature has a bias to those articles and research documents published by those working in the field of water resources. This is despite the fact that a very rich body of literature and experience in applying optimization models to real life situations exists in other fields, such as hydroelectric power generation. On the other hand, a review of the literature on the methods used to model all aspects of the operation of power systems, including scheduling of hydroelectric facilities (IEEE Working Group Report, 1981) had little mention of the rich literature produced by those working in the area of water resources management, as described by Yeh.

2.1.3 Current State-of-the-Art

During the 1980s and up to the time of writing this thesis, the literature concerning old and new techniques for solving the problem of scheduling generating facilities is profuse. A literature search on generation scheduling methods and reservoir operations is a major undertaking by itself. Several reviews and surveys were conducted by different working groups on the methods used for short-term scheduling of power system operation and control. These surveys highlighted the conclusions arrived at by Yeh: that although most utilities expect significant savings in operation costs from improvements in short-term scheduling procedures, few utilities actually use them. This was also highlighted in the conclusion of a survey that included 54 utilities worldwide: "The lack of advanced methods for short-term operation scheduling of generation facilities is apparent" (Working Group No. 3, 1986). Furthermore, the survey indicated that most of the reporting utilities paid more attention to scheduling and optimizing thermal generating units, while optimizing hydro generating systems have received very little, if any, attention. This is despite the fact that most of the reporting utilities surveyed have recognized the potential significant savings that could be achieved.

More recently, other researchers tried old and new techniques to solve the generation scheduling problem. Successive linear programming was applied by Tao to study the High Aswan dam and answered several questions on using the method for reservoir operations (Tao et al. 1991). Gustavo et al., applied Sequential Quadratic Programming to a hydropower system to investigate the optimal allocation of releases from power plants during peak demand periods (Gustavo et al., 1990). The method was found to be feasible and superior to successive linear programming (faster convergence to the optimal solution). Russell et al., investigated reservoir operating rules with the application of fuzzy programming techniques, and found that the method is not an alternative to conventional optimization techniques (Russell et al., 1996). However, they suggested that fuzzy rules could complement optimization techniques by introducing flexibility and responsiveness, particularly if expert operator's insights were incorporated. Linear network flow techniques (Franco et al., 1994; Wang et al., 1990; Nabona, 1993), and nonlinear network flow algorithms (Rosenthal, 1981) were also tried for hydroelectric power systems. Allen and Larson applied dynamic programming techniques to short-term hydroelectric optimization problems (Allen et al., 1986; Larson 1969). Oliveira in Scotland applied a mixed integer linear programming algorithm to solve the short-term scheduling problem for a hydrothermal system with pump storage facilities. The algorithm solves a simpler linear programming problem, derived from the original mixed integer problem, by relaxing the integer to interval constraints, making the problem easier to solve. Other researchers in Canada adopted a reliability-programming model for hydropower optimization (Srinivasan et. al., 1994). In this modeling approach, the stochastic nature of inflows is considered in the formulation of a chance constrained linear program. In this approach, a nonlinear search algorithm evaluated reliabilities with two linear programming routines. One was used to evaluate the optimal policy for the chosen reliabilities, while the other evaluated the optimal value of the objective function. The model also includes a linearization procedure for the energy function to determine the head-related coefficients. Finally, Acres International reviewed and assessed the models and methods used by Canadian Utilities to schedule power generation facilities in 1994. The study objective was to develop a framework for a comprehensive decision support system to solve the problem. The study recommended solution of the problem by the Lagrangean method by decomposing it into the unit commitment and the economic dispatch sub-problems. Extensive use of linear network programming methods was recommended (Acres International, 1994).

Others tried Genetic algorithms (GA) to solve the reservoir operation problem. Wardlaw et. al., evaluated Genetic algorithms for optimal reservoir system operation, and found the search method to be robust and could easily be applied to complex systems (Wardlaw et. al., 1999). However the authors indicated that GA fall short of finding the global optimal solution which was arrived at by linear programming. They further reported that the execution time of GA was eight times longer than that of LP, for a problem of 10 reservoirs for 12 time steps. In addition, and for extended the study duration, GA encountered convergence problems, which required further modifications to the algorithm. The major advantage of using GA, however, is its ability to easily handle nonlinear problems, and it has potential as an alternative to stochastic dynamic programming. Oliveira and Loucks also used GA to evaluate operating rules for multireservoir systems, and were concerned with optimization the parameters of the operating policies or rules (Oliveria et. al., 1997).

Lund and Guzman derived a set of conceptual rules for operating policies for reservoir in series and in parallel (Lund et. al., 1999), and used an LP model to allocate storages among reservoirs in series and in parallel to maximize hydropower production. Israel and Lund presented an algorithm for determining priority-preserving unit cost coefficients in a network flow programming framework and used an LP program to serve as a preprocessor to the program (Israel et. al., 1999). Teegavarapu and Simonovic used membership functions from fuzzy set theory to represent the decision maker's preferences in the definition of shape loss functions (Teegavarapu et. al., 1999). Yang and Read used a constructive dual dynamic programming approach for a reservoir model with serial correlation. They indicated that sginificantly better operating policies could be obtained by accounting for the correlated inflows (Yang M. et. al., 1999). Finaly, several authors reported the use of evolutionary pogramming techniques to solve the unit commitment and short-term operation planning of hydrothermal power systems (Werner, T.G., 1999; Juste K.A., et al., 1999). Like GA, evolutionary methods are too slow for real-time applications.

2.2 STATE-OF-THE-ART IN INDUSTRY

From the perspective of the research reported on in this thesis, the most important of the techniques (old and new) are those which contributed to applied methods of analysis, and those which presented methods that cover the overall framework for operations planning of generating systems that are predominantly, or with significant hydroelectric components. Such techniques were developed, in most cases, in response to the needs of utilities that actually operate complex generating systems, which contains significant hydroelectric components. With this in mind, review of the literature on the methods employed to solve applied hydroelectric scheduling problems revealed that few researchers have attempted to solve the problem in its entirety. What could be found were methods that, predominantly, considered scheduling of thermal generation as a major component of the mix of resources used. However, the literature included the work of a number of research teams who focused on systems that are predominantly, or purely, hydroelectric in nature. The most relevant of these are discussed in the following sections.

2.2.1 The Norwegian Electric Power Research Institute (EFI)

The Norwegian system is part of the Nordic power system covering Norway, Sweden, Finland and Denmark. A number of papers by several researchers with EFI outlined the methodology used to manage the predominantly hydroelectric Norwegian system (Mo et al., 1997; Johannesen et al, 1997; Fosso et al., 1997; Gjelsvik et al., 1992; Hjertenaes et al., 1992; Johannesen et al., 1989). In these papers, the authors presented the overall framework for scheduling a hydro-dominated power production system. The Norwegian generating system is more than 99% hydroelectric, with more than 70 generating companies, each responsible for scheduling their own operations. A power exchange (Nord Pool) and a system operator are responsible for marketing and system coordination operations. The power exchange is guided by a set of agreed-upon rules that define the sale of electrical energy and the spot price market clearance structure in the pool. The methodology developed at EFI and adopted in Norway followed closely the work of Lindqvist back in the 1960's (Lindqvist, 1962). Lindqvist's basic approach was extended to account for deregulation of the electric industry in Norway. The methodology follows a modeling hierarchy for the long, medium, and short-term scheduling of the hydroelectric system, and is summarized as follows. More details on the methodology can be found in the above-cited references. A stochastic dynamic programming model derives the long-term system operating strategy (Gjelsvik et. al., 1992). The model aggregates the system resources as one reservoir and then determines the value of expected hydroelectric energy production and the associated energy storage for each time step. Inflows, prices and demand for energy are modeled as stochastic variables. The medium-term target storage levels are determined from the long-term model, which are then used in medium-term models as constraints. The medium-term models are deterministic linear models, which treats uncertainty in inflows by generating a number of scenarios (stochastic dual dynamic programming (SDDP) is considered as an alternative for the medium-term modeling process described above). Results from the medium-term models consist of endpoint storage cost descriptions for use in the short term scheduling model. The short-term hourly scheduling problem is solved as a deterministic large-scale linear programming algorithm, and it includes more detailed description of the system than the other higher level models. The medium and short-term models are coupled through the incremental water value descriptions. These descriptions account for perturbations of the reservoir contents in relation to the contents of other reservoirs. This is modeled in the short-term by the use of penalty-function representation of the endpoint reservoir descriptions (see Mo, 1997 for details). The objective of the short-term model is to optimally match supply and demand by considering the long-term objectives (represented by reservoirs' targets and water values) and the short-term market prices. The modeling methodology presented by the Norwegian researchers is considered to be one of the most appropriate methods found in the literature to-date, as it considers a hydro-dominated generating system, managed by individual generating companies, operating in a deregulated market structure. However, although the modeling approach is appealing, it can not be readily adopted as a standard approach that could be applied to the B.C. Hydro case without further research and development for at least three reasons. First, the configuration and characteristics of the market structure for B.C. Hydro is different than the Norwegian case (two market structures: Alberta and the U.S., each with different characteristics). Second, the characteristics and the constraints governing the operation of the B.C. Hydro system (e.g., environmental considerations, the Columbia Treaty, and the Peace River operating regime) differ from those in Norway. Third, the B.C. Hydro system enjoys a larger storage capacity and more flexibility than the Norwegian system.

2.2.2 *The University of Waterloo (Unny et al., 1982)*

A hierarchical approach consisting of a number of statistical and optimization models for the long, medium, short-term, and real-time for the serially connected Alcan multi-reservoir system in Quebec was developed. The long, medium and short-term models provide an operational policy (in the form of rule curves for reservoir states) that real-time operators must comply with. The real-time scheduling problem is formulated as a linear model that determines the hourly schedule for one day, which minimizes energy use for fixed reservoir states at the end of the study period. Several iterations between the short and the real time models are performed to adjust for discrepancies in flow and load forecasts.

2.2.3 *Hydro Quebec (Turgeon, 1982)*

In 1982, Turgeon compared three methods for short-term scheduling of hydro plants in series: dynamic programming; the progressive optimality algorithm; and the discrete maximum principle. He concluded that the progressive optimality algorithm was the most suitable to solve the problem. However, Robitaille (Robitaille et al. 1995) and Lafond (Lafond, 1997) reported the development and implementation of a real-time river management system for Hydro-Quebec for short-term operations. The method used for the short-term hydroelectric generation scheduling uses a successive linear programming approach. The short-term scheduling model is used to maximize the efficiency of the hydroelectric system in a single river basin. As Lafond puts it, the objective function used in this scheduling system "parallels the current practice of the dispatcher, it is considered to provide the best basis for a first regional optimization tool when used over a rolling horizon and with appropriate final (reservoir) state lower bounds."

2.2.4 *Centro de Pesquisas de Energia Electrica, Brazil (Pereria et al., 82; 83, 85; 89; 91)*

In a series of journal articles in the 1980's and early 1990's, Pereria introduced a methodology for centralized operation planning of the predominantly hydroelectric generating system in Brazil. The methodology decomposed the planning activities into three major levels: long-term, medium-term, and short-term scheduling. To derive a long-term strategy over a five-year planning horizon, the systems of reservoirs are aggregated into one reservoir and a stochastic dynamic programming model is used to derive weekly tables describing the optimal proportion of hydro and thermal generation as a function of aggregate system storage. The medium-term desegregates the weekly generation schedule for the aggregate reservoir into generation targets for each plant in the system. The problem is formulated as a non-linear programming problem and is solved by the method of successive linear programming. The short-term scheduling problem is solved as a large-scale linear program, which produces hourly generation schedules. The generation targets calculated by the medium-term model determine weekly targets that the short-term models should meet. Since the weekly target energy levels might not produce an electrically feasible schedule in the short-term, a new methodology aimed at finding a global optimal solution was proposed. This methodology is iterative and uses the Benders decomposition technique that divides the global problem into two independent sub-problems: master problem, and sub-problems (see Pereria et al., 1983 for details). Although the above methodology has significantly contributed to the theory of planning reservoir operations, it seems that centralized implementation had some difficulties. For example, in 1995, Lyra and Ferreira with the State of Parana Energy Company in Brazil indicated that "Even though utilities operate under guidelines established by government regulations and operation agreements, the best overall (centralized) scheduling may not meet their individual interests." They further described a multi-objective approach to the short-term scheduling of the hydroelectric system managed by "their" company. The model utilizes the concept of discrete differential dynamic programming, where the optimization problem for serially connected reservoirs is decomposed into a series of optimal control problems (see Lyra et al., 1995 for details). Further, and in 1997, de Sa Jr et al., (with one of the Brazilian Electric Utilities in Rio de Janeiro) proposed a "simple optimization approach" that uses a linear programming model to act as an interface between the short-term planning and the real-time dispatch of generating units. The model accounts for the hydro system constraints and the objective seeks to maximize reservoir storage at the end of the study period.

2.2.5 *The University of California, Los Angeles (Yeh et al., 1992)*

In 1992, Yeh presented a multilevel management scheme applied to a hydrothermal system in China. The scheme includes a monthly, daily and hourly optimization model that aims at finding the hourly schedule of thermal and hydroelectric plants to minimize the cost of thermal power generation. The monthly and daily models determine the allocation of hydropower in each month of the year and for the first month in the study. This allocation is then used in the hourly model as a constraint. The hourly model incorporates transmission losses but does not include the continuity equation for reservoirs. The monthly and daily optimization are solved by an LP-DP algorithm, while the Incremental Dynamic Programming with Successive Approximation technique was used to solve the hourly optimization problem.

2.2.6 *Georgia Institute of Technology (Georgakakos, 1997)*

Several authors have investigated the potential use of control engineering methodologies for water resources and reservoir operations (Chan et. al., 1975; Wasimi et. al., 1983; Georgakakos, 1997). These methods are efficient in finding a solution to the reservoir operation problem. Their efficiency stems from the great saving in computer memory space due to the fact that they do not discretize the state variables, as in dynamic programming. Chan suggested the use of an iterative tracking algorithm for routing stormwater through a combined sewer network. Wasimi et. al. suggested the use of linear quadratic Gaussian

(LQG) control method with the tracking algorithm for real-time daily operation of a multi-reservoir system under flood conditions. The basic idea of LQG methods is that they use penalty functions to direct the objective function towards an optimal (or near optimal) path or trajectory. In some sense it resembles the method suggested by Sigvaldason in 1976 as described above. Georgakakos et. al. extended the LQG control method to solve the problem in an iterative optimization procedure that starts from an initial sequence of the control variables and generates better sequences, by using analytical techniques, until convergence is achieved (for details on the method see Georgakakos et al., 1987, 1993a, 1993b; Georgakakos 1989). However, although very efficient, the procedure does not guarantee global optimality (Georgakakos, 1997).

2.2.7 The Pacific Gas and Electric Company (Ikura et al., 1984)

Ikura reported the development of a solution methodology for a weekly (or monthly) large-scale hydroelectric scheduling problem. The main contribution of the research is the explicit consideration of forced spills (over a spillway when reservoir storage are at their upper limit) in the problem formulation by means of introducing a penalty in the objective function. A network flow algorithm provided a good starting solution to the problem. Thereafter, the problem is formulated and solved as a non-linear programming algorithm using the quasi-Newton scheme in the commercial package Minos (Murtagh et. al., 1978).

2.2.8 Tennessee Valley Authority (TVA)

Although TVA has been trying to optimize its large-scale hydrothermal system for a number of years, and have tried the majority of the available optimization techniques (see Giles et al., 1981; Giles 1988), only recently have they engaged in the development of a comprehensive modeling environment that uses linear programming at its core (Magee et al., 1994; Shane et al, 1995). In fact TVA have specifically requested the development of a prototype optimization model that uses a commercially available, robust linear solver. As reported by Magee on the development of the TVA prototype system, the modeling methodology relies on minimizing the violation of a set of prioritized policy constraints. The policy constraints contain a wide range of constraints: guide-curves, flow, pulsing, no-spill, navigation, and systems storage constraints, etc. The objective function maximizes the economic benefits of power generation. The economic value to be maximized represents the value of immediate power generation against future expected value of water in storage, which is given by economy guide curves. The immediate value of hydropower is defined as the thermal replacement value of hydropower generated.

2.2.9 Electricite de France (Renaud, 1993; Goux et al., 1997)

Renaud and Goux described a methodology for optimizing the complex, large-scale, generation system in France. The French system consists of 60 nuclear power plants, about 100 thermal power plants, and hundreds of hydroelectric plants located in more than fifteen river systems, with a number of very large storage facilities (a truly large-scale system). The short-term generation scheduling activity for the generation system is centralized in France. Since global optimization of such a system is very difficult (some of the thermal cost functions are non-convex), and impractical, a decomposition approach is being used. The decomposition approach is based on the method of "price decomposition" (which relates to the use of the Lagrangian multipliers). Decomposition is done for each homogenous type of activity in the electric system (thermal and nuclear generation; hydroelectric generation; and transmission network). For each type, a sub-problem is formulated and optimized by different algorithms, and the problems are then pasted together and globally optimized by using the "Augmented Lagrangian and Splitting Variables technique". Although this technique is reported to be efficient in solving the global optimization problem, it is not of great interest to this thesis (since the French system consists largely of nuclear and thermal system). What is interesting, however, is that linear programming was used to solve the (large-scale) scheduling problem for the hydroelectric sub-problem. Although the hydroelectric model used is greatly simplified, future enhancements are foreseen to improve the representation of the hydroelectric system (see Renaud, 1993, Batut, 1992 and Goux, 1997 for more details).

2.2.10 Hydro Electric Commission of Tasmania, Australia (Piekutowski, et al., 1994)

Piekutowski reported on development of a large-scale hydroelectric scheduling model that included a detailed description of a serially cascaded reservoir system. The model was developed to determine the optimal generation schedules and to investigate the export and import capabilities under a proposed tie line between the Island of Tasmania and mainland Australia. The model includes equations that describes forced spill conditions, storage target penalty functions, load-resource balance, energy-discharge input/output, and system hydraulics. The problem is formulated as a large-scale linear algorithm and is solved by a commercially available linear solver. The authors highlighted one of the advantages of using linear programming as the solution method: the fact that the units' incremental costs can be derived from the dual variables of the linear program solution and that the system incremental cost can be obtained form the dual variables of the load-resource balance equation. The units' incremental costs were used to provide a ranking of the units for real-time dispatch while the system incremental costs was used for scheduling trading transactions.

2.3 SUMMARY

Over the last seventy years, several researchers and practitioners have devoted considerable effort to develop techniques that can be used at one or more of the various levels of operations planning of hydroelectric and thermal facilities. In summary, there is no single type of reservoir operation problem, but rather, a multitude of decision problems and situations. Each hydroelectric scheduling system and each study reviewed is unique. Several types of decision variables, decision criteria and constraints have been modeled and incorporated into various simulation and optimization modeling studies and applications. There is no simple answer to the question of which models and analysis techniques should be used for a particular situation and application. However, several key factors to be considered in formulating an applied modeling and analysis approach for a particular application are discussed in Chapters 4 and 5. But before concluding this section on literature review, it could be said that linear programming is one of the most widely adopted optimization techniques for real-life applications in the hydropower industry all over the world. This is despite the fact that the problems are internally nonlinear and many other techniques have been suggested and used in different circumstances.

Before addressing the question of "Why use linear programming?" it is appropriate here to recall some of the main features of the technique. Linear programming has become a very popular tool for use in optimization problems in industrial applications. One of the reasons is that very large problems can be solved with reasonable computer resource and time. Problems with a few hundred thousands variables and a matching number of constraints can now be routinely handled and solved efficiently. Also, a major investment in terms of manpower and expertise has been put into the development of general-purpose solvers and algebraic modeling languages that can efficiently solve large-scale problems and also handle non-linear problems by iterations. The linear programming technique also has the advantage over other optimization methods of being well defined and easy-to-understand and explain to end-users. In addition, a linear objective function and a set of linear or piecewise linear constraints can realistically represent many reservoir operation problems. Although the methodology is widely used, and is capable of solving large-scale problems, it suffers from the fact that the problems must be stated in an algebraically linear or piecewise linear form.

The short-term, hourly hydroelectric scheduling problem is a large-scale optimization problem that has received some attention from academics and practitioners working in the field. Several techniques to solve the problem have been reported in the literature. The Lagrangian relaxation approach (known as the Lambda technique), gradient search techniques (non-linear optimization), and dynamic programming can be used. However, convergence to the optimal solution in these methods (if found) could be slow. For real-time scheduling of large-scale hydroelectric systems, dynamic programming becomes unattractive since the methodology suffers from the curse of dimensionality -requiring computer memory and storage of unattainable size, and processing speed of considerable magnitude. For these reasons, and due to its attractive features described above, the linear programming technique is considered the best to handle the large-scale hydroelectric scheduling problem considered in this thesis. In addition, the availability of proven and robust commercial software packages to solve linear programming problems reliably and efficiently supported the choice of linear programming as the 'method of solution' for the optimization problem.

CHAPTER 3

THE DECISION MAKING ENVIRONMENT

This Chapter describes the decision-making environment and the rationale for developing the subject matter of this thesis: the decision support system for hydroelectric generation scheduling in a competitive market environment. The Chapter starts with a brief description of the BC Hydro power system. Then the current planning environment and modeling techniques employed at B.C. Hydro are briefly described. The extent of the decision-making environment in a large-scale hydroelectric system, and available methods and analytic techniques, and the classification of decision problems are briefly described.

3.1 THE B.C. HYDRO POWER SYSTEM

The historic development of the B.C. Hydro generating system is described, and the main components of the electric system are outlined with an emphasis on the hydroelectric generating facilities. Then a glance at the future and the efforts taken by B.C. Hydro to shape it to meet the challenges ahead are outlined.

3.1.1 Historic Development of B.C. Hydro's Generating Facilities

Soon after the invention of electricity towards the end of the last century, hydroelectric generating stations and delivery systems started to be built to make electricity available to consumers. In British Columbia, hydroelectric generating facilities have grown hand in hand with the economic and social development of the province. For example, the Vancouver Street Railway Company ran the city's first electric streetcar in 1890, while the British Columbia Electric Railway Company developed the first hydroelectric plant in British Columbia at Goldstream near Victoria in 1898. Soon afterward, domestic and industrial demand for electricity grew, and several other plants were developed at Lake Buntzen (1903) in the Lower mainland and at the Jordan River in Vancouver Island (1911). Soon afterward, private companies developed many other hydroelectric facilities across the province. Electricity generated by other companies was mainly devoted for industrial use (e.g., West Koontenay Power and Light Company). Prior to 1945, many communities had no electricity at all. In that year the B.C. provincial government created the B.C. Power Commission which set the stage for a consolidated effort at acquiring the small fragmented companies and extending the service to rural isolated areas, and building new generating stations and expanding the transmission system. The results were electrification of over 200 communities all over the province. As the province population grew, demand for electricity increased. B. C. Electric constructed large-scale hydroelectric projects on the Bridge River (1948) and B.C. Power Commission on the Campbell River (1953). By 1960, construction of the natural gas-fired Burrard Thermal Generating Station began with the aim to serve the ever-growing demand in the Lower Mainland.

After World War II, considerable development of hydroelectric facilities took place in the United States of America. Some of the major developments were in the Pacific Northwest on the Columbia River System. Efficient operation of the U.S. facilities required construction of large storage facilities on the Canadian side. The B.C. provincial government and the Americans realized the potential gain in coordinating their efforts to develop large-scale infrastructure facilities required for tapping the resources of one of the continent's great rivers, the Columbia. In addition, the provincial government realized the potential in developing the Peace River. In 1961 the government stepped in to buy B.C. Electric and gave it the task of developing the Peace River generating facilities. One year later, the government joined B.C. Electric with the Power Commission and created the B.C. Hydro Power Authority, known now as BC Hydro.

One of the first accomplishments of B.C. Hydro was the 1964 development of the International Columbia River Treaty. Soon afterward, B.C. Hydro undertook the development of some of the most extensive hydroelectric facilities in the world. During the period 1964-1974, several mega-scale projects were developed on the Columbia and the Peace Rivers (see Table 3.1). By 1980, generating capacity increased to almost 8000 Megawatts –an increase of more than five times the capacity in 1962.

During the 1980's development of generating facilities slowly declined, and a major restructuring of B.C. Hydro took place. The restructuring was aimed at separating B.C. Gas and public transit that had been inherited from B.C. Electric. Towards the end of the decade, the installed capacity has risen to about 10500 megawatts. New sources of electricity supply were sought from nontraditional sources, such as demand-side management, and new partnerships with the independent power producers. The introduction of independent power producers meant that B.C. Hydro was not the sole producer of electricity in the Province. In 1990's, the concept of publicly owned utilities was challenged. Monopolies over basic services such as communication, gas, and electric power were undergoing deregulation. These changes are said to be driven by many factors including customers' demand for new services and supply and pricing options, technology improvements, new independent power producers, and legislative and regulatory movement toward more competitive industries. Accordingly, in 1995, B.C. Hydro announced a major restructuring aimed at dealing with the new competitive arrangements. The fallout of this restructuring was a new organization structure that consists of three basic business units: Power Supply, Transmission and Distribution, and Marketing and Customer Services. The Power Supply Business Unit manages the generating facilities, while the Transmission and Distribution Business Unit manages the transmission and distribution network, and the Marketing and Customer Services Business Unit deals with the sale of electricity to B.C. Hydro customers. Within the Marketing Business Unit, PowerEx deals with electricity trade activities outside of the Province.

If full deregulation had its way, and B.C. Hydro were privatized, the electricity industry in British Columbia would have gone through a full long cycle, following the hypothesis of long waves (Kondratieff, N. D., 1935). For a historical and personal account of the development of B.C. Hydro and its predecessors since 1860, see the newly published book (1998) "Gaslights to Gigawatts: A Human History of B.C. Hydro and its Predecessors" by the Power Pioneers –a group of B.C. Hydro former employees.

3.1.2 The B.C. Hydro Electric System

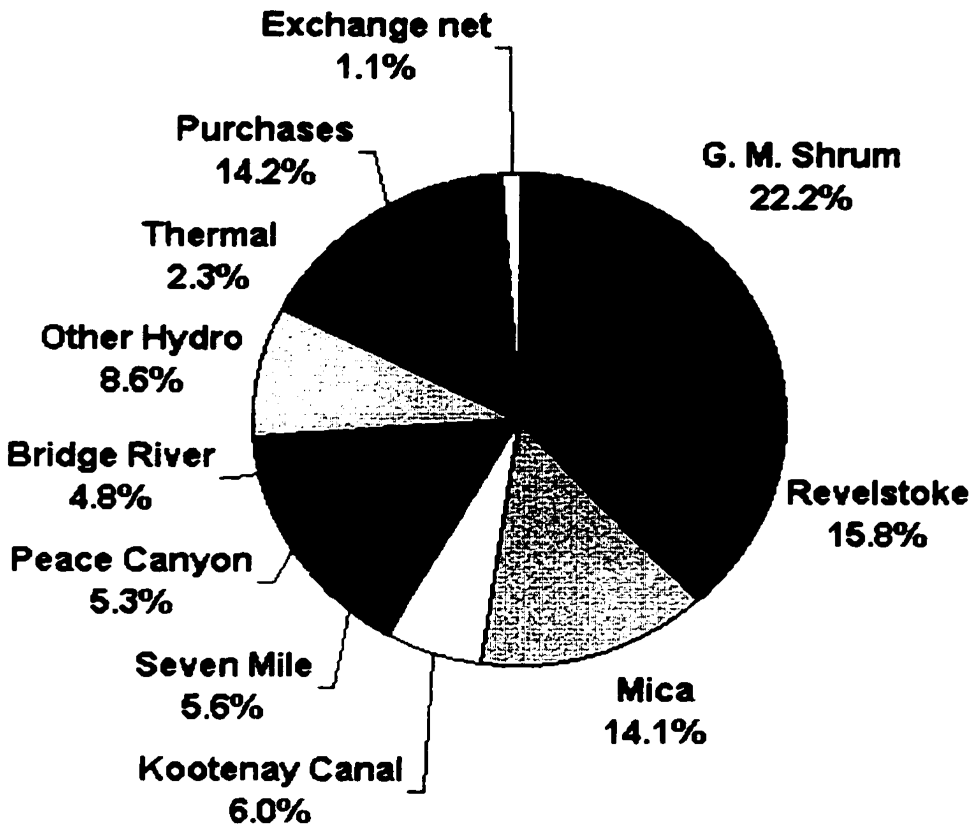
The B.C. Hydro electric system consists of two major components: the generating system and the transmission and distribution system. Through a complex set of generating, transmission, and distribution facilities, electricity generated by B.C. Hydro is delivered to 1.53 million residential, light and large industrial customers in British Columbia and trade customers in Alberta, and the U.S. (B.C. Hydro, 1998). In the following sub-sections, the B.C. Hydro generation, transmission and distribution systems are briefly described.

i. The Generation System

B.C. Hydro operates 30 hydroelectric facilities with 32 reservoirs in 6 major basins and 27 watersheds, and three thermal generating plants. Table 3.1 lists the majority of existing hydro and thermal generating facilities, their commissioning dates and generating capacities, and the system of reservoirs managed by B.C. Hydro along with their live storage capacities. Other minor generating plants and their associated facilities are not included in the table.

Table 3.1 indicates that over 90% of the installed generating capacity of about 11,200 MW is hydroelectric. Two of B.C. Hydro reservoirs provide multi-year live storage: the Williston on the Peace River (40 billion M^3), and the Kinbasket on the Columbia River (14.8 billion M^3) – enabling B.C. Hydro to strategically plan their operations for several years ahead. About three-quarters of the electricity is produced at major installations on the Peace and Columbia River systems, while other main energy sources include smaller hydroelectric facilities on the B.C. Coast, the lower mainland, and Vancouver Island, and a natural-gas-fired generating station in the Vancouver area. Thermal generating facilities are used to supplement the hydroelectric system in years of low water flow and during periods when natural gas prices are low (mainly during summer).

In terms of firm energy capability (the assured energy contribution of the electric system over one year), the B.C. Hydro system provides for about 50,000 gigawatt-hours of energy per annum. A 100-watt light bulb switched on for one hour consumes 100 watt-hour, and one gigawatt-hour can serve about 100 residential customers for about one year. On average, thermal generation contributes about 3.5%, while energy purchases contribute about 1.5% of total energy use, with the balance provided from hydroelectric generating facilities. Figure 3.1 illustrates distribution of sources of supply for the year ended March 31st, 1998.



Source of data: BC Hydro, 1998a.

Figure 3.1. Sources of Electricity Supply in 1998.

Table 3.1. Plants and Reservoirs Managed by B.C. Hydro

Plant Name (Commissioning)	Installed Capacity (MW)	Plant Type & Avg. H/K ($MW/m^3/s$)	Reservoir and Storage (Million M^3)
Peace Region			
G. M. Shrum (1968)	2730.0	Hydro (1.43)	Williston (39,472)
Peace Canyon (1980)	700.0	Hydro (0.34)	Dinosaur (216)
Subtotal	**3430.0**		**39,688**
Columbia Region			
Mica (1977)	1840.0	Hydro (1.49)	Kinbasket (14,800 Columbia Treaty)
Revelstoke (1984)	2000.0	Hydro (1.15)	Lake Revelstoke (5,304)
Seven Mile (196?)	594.0	Hydro (0.53)	Pend d'Oreille (60)
Waneta (1954)	360.0	Hydro (0.51)	Waneta (5)
Duncan Dam (1967)	-	-	Duncan Lake (1,727 Columbia Treaty)
Keenleyside (1968)	-	-	Arrow Lakes (8,758 Columbia Treaty)
Kootenay Canal (1976)	528.0	Hydro (0.71)	Kootenay Lake (Run of river)
Whatchan (1951)	50.0	Hydro (1.60)	Whatshan Lake (271)
Elko (1924)	12.0	Hydro (0.47)	Elk River Headpond (Small/run of river)
W. Hardman (1960's)	8.0	Hydro (1.82)	Coursier Lake (29)
Aberfeldie (1922)	5.0	Hydro (0.65)	Bull River headpond, (run of river)
Spillimacheen (1955)	4.0	Hydro (0.53)	Run of river
Subtotal	**5410.0**		**30,954**
Lower Mainland/ Fraser Region			
Burrard (1962)	912.5	Thermal/Gas	-
Alouette (1928)	8.0	Hydro (0.34)	Alouette Lake (155)
Stave Falls (1911)	50.0	Hydro (0.28)	Stave Lake (468)
Ruskin (1930)	105.0	Hydro (0.28)	Hayward Lake (24)
Buntzen (1903)	72.8	Hydro (1.03)	Buntzen Lake/ Coquitlam Lake (202)
Cheakamus (1957)	155.0	Hydro (2.52)	Daisy Lake (46)
Clowhom (1958)	33.0	Hydro (0.41)	Clowhom Lake (105)
Wahleach (-)	60.0	Hydro (4.84)	Jones Lake (66)
La Joie (1956)	24.0	Hydro (0.49)	Downton Lake (722)
Bridge River (1948)	480.0	Hydro (3.15)	Carpenter Lake (1,011)
Seton (1956)	44.0	Hydro (0.40)	Seton Lake (9)
Shuswap (1929)	5.2	Hydro (0.19)	Sugar Lake (148)
Subtotal	**1949.5**		**2,856**
Coastal Region			
Prince Rupert (-)	46.0	Thermal/Gas	-
Falls (1930)	7.0	Hydro (0.46)	Big Falls Lake (24)
Subtotal	**53.0**		**24**

Vancouver Island Region			
Jordan River (1911)	170.0	Hydro (2.58)	Elliot, Diversion, Bear Creek Res. (28)
Strathcona (1958)	56.0	Hydro (0.32)	Buttle Lake (823)
Ladore (1958)	47.0	Hydro (0.28)	Lower Campbell Lake (317)
John Hart (1953)	126.0	Hydro (1.03)	John Hart Lake (3)
Ash River (1959)	27.0	Hydro (1.96)	Elsie Lake (77)
Puntledge (1912)	24.0	Hydro (0.88)	Comox Lake (106)
Keogh (mid 1970's)	99.7	Thermal/Gas	-
Subtotal	**549.7**		**1,354**
Grand Total	**11,383.2**		**74,876**

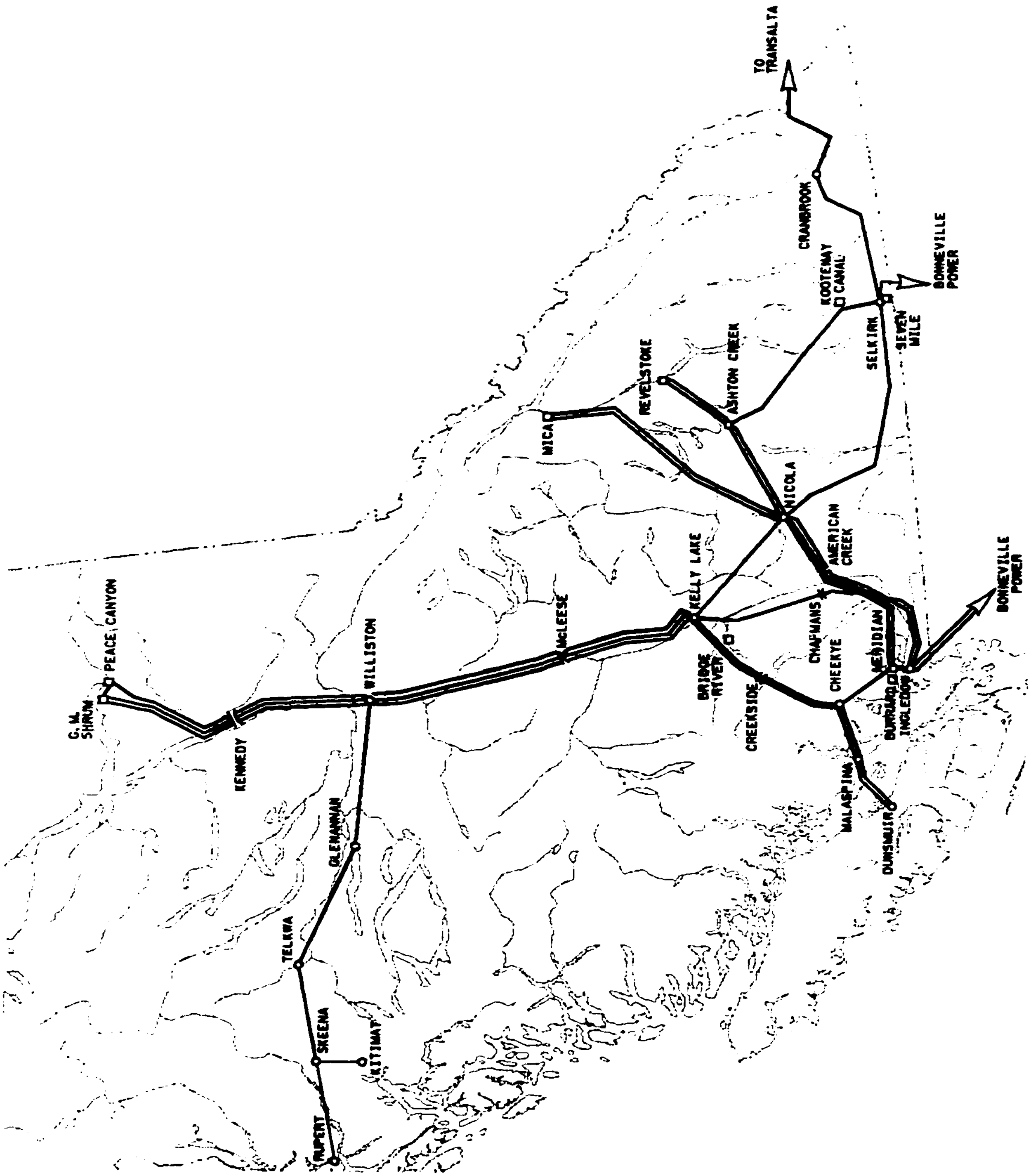
Sources: BC Hydro, 1993 and personal communication.

* H/K is a proxy for the plant efficiency, and is calculated from long-term studies as the average plant generation in Mega Watt/ plant discharge in cubic meters per second. It is a commonly used term in industry.

ii. The Transmission and Distribution System

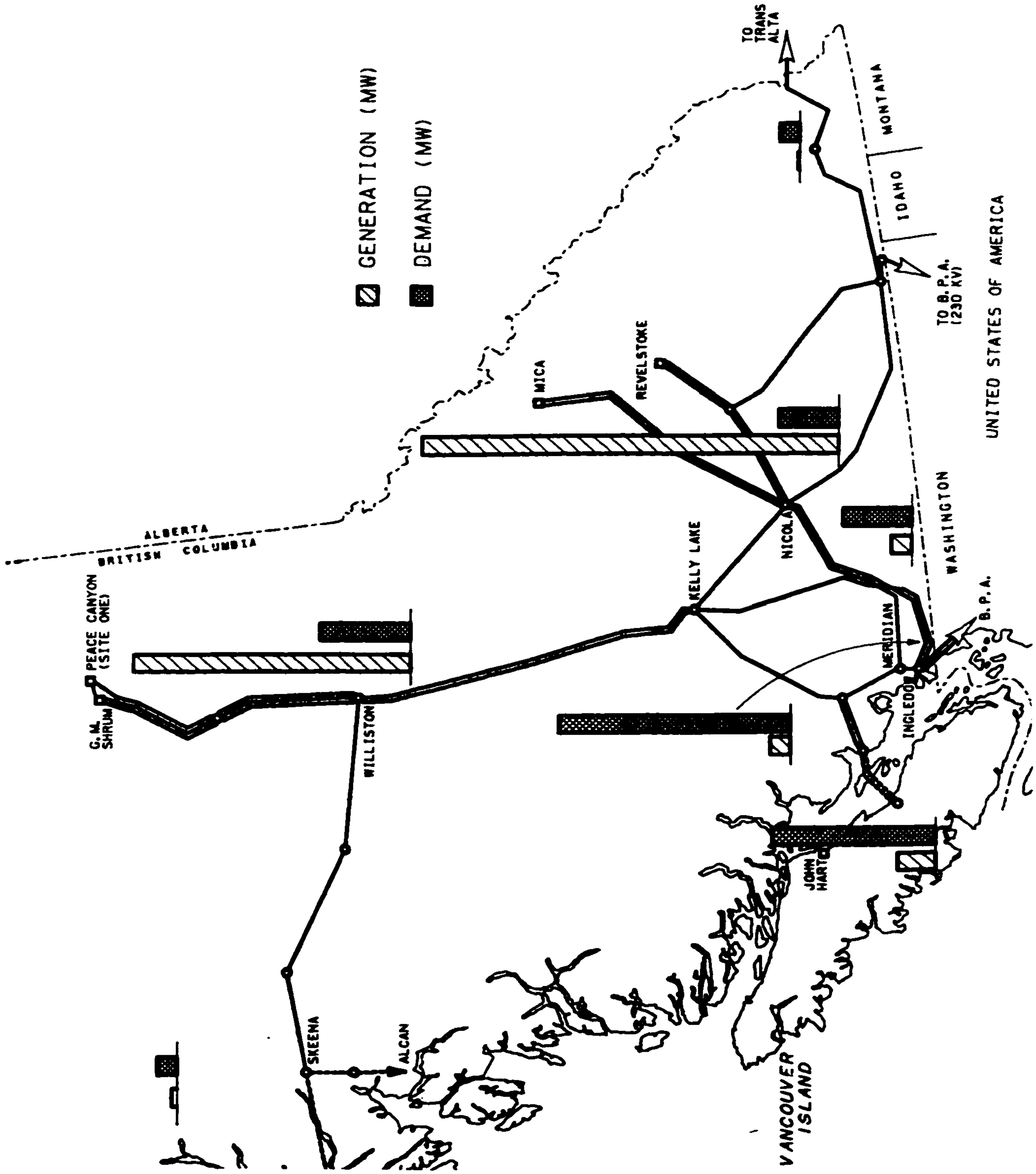
The transmission network connects the generating facilities with the major demand centers in the Province. The imbalance between generating resources and demand centers has shaped the development of the B.C. Hydro transmission network. Figure 3.2 is a map of the B.C. Hydro major electrical transmission system facilities, and Figure 3.3 illustrates the distribution of generating capacity and electrical demand centers in British Columbia. Also shown in Figures 3.2 and 3.3 are the connections between the B.C. Hydro transmission network and the Alberta and the western U.S. transmission networks. The tie line capacity to Alberta is rated at 1100 MW of transfer capability, while the U.S. total tie line capacity has been upgraded recently to 3250 MW. The transmission network consists of 17,600 km of high voltages transmission lines (above 60 kilovolts).

Terminal stations serve two purposes: they control energy flow in the transmission network; and they reduce voltage to distribution line levels. The distribution network connects consumers to the transmission network through 51,400 km of distribution lines. Distribution substations reduce voltage as needed for residential, commercial, and small and medium industrial customers.



Source: BC Hydro, 1994

Figure 3.2. Map of BC Hydro's Major Electrical System.



Source: BC Hydro, 1994

Figure 3.3. BC Hydro's Present Regional Generation-Demand Balance.

3.1.3 Looking Ahead and Shaping the Future

This section presents the current regulatory framework for the electric industry in British Columbia. Then the main forces that are believed to be causing the ongoing changes in the electricity market, and the steps that are currently being undertaken by B.C. Hydro to prepare the organization for the uncertain future that lies ahead, are discussed.

i. Current Electricity Regulatory Framework in British Columbia

Three types of electric utilities exist in British Columbia: publicly owned, privately owned, and municipally owned. As shown in Table 3.2 below, B.C. Hydro is the only electric utility that is publicly owned.

Table 3.2. Electric Utilities in British Columbia

Publicly Owned
• B.C. Hydro
Privately Owned
• Hemlock Valley Electrical Services • Princeton Light and Power • West Kootenay Power • Yoho Power • Yukon Electrical Company
Municipally Owned
• City of Grand Forks • City of Kelowna • City of Nelson • City of New Westminster • City of Penticton • City of Summerland

Source: BCUC, 1995.

The total installed generating capacity in B.C. is about 13,300 MW, while annual production level is estimated at more than 60,000 giga-watt-hours. Hydroelectric generation accounts for about 85 percent of total installed capacity, with the balance being other sources such as oil, natural gas, woodwaste, and other thermal sources. In terms of installed capacity, sales, and customer base, B.C. Hydro dominates, as it controls more than 82% of the installed capacity, and 94% of the electricity sold in the Province. A small number of Independent Power Producers (IPPs) and large industries also generate electricity in British Columbia. IPPs either sell their electricity production to B.C. Hydro, West Kootenay or to the export market. In addition, there are a number of large industries (e.g., ALCAN) who generate electricity to meet their needs, and their generators could be in the form of co-generation –as in the case of some energy intensive industrial processes (e.g., that require pressurized steam). The total IPPs and industrial installed generation capacity accounts for approximately 2300 MW, of which more than 80% is generated by industries. The IPPs role as suppliers of electricity to B.C. Hydro was reinforced through a policy statement that was issued by the province in 1992. This policy statement encourages IPPs where a need had been identified and where they could provide cost advantages, innovation or expertise. However, IPP future investments were limited to undeveloped sites with low hydropower potential and to other generation technologies (wind, woodwaste, etc).

As with many electric industries around the World, the publicly owned electric utilities in British Columbia are regulated by government entities. Aside from municipalities, the B.C. Utilities Commission (BCUC) regulates all other electric utilities in British Columbia. The Commission's powers include utility's expenditures and the corresponding rates charged to customers. The rates have traditionally been set on a cost of service basis that limit the rates to the forecast cost of serving the customers including a reasonable return on investment. The Crown Corporations Secretariat also oversees B.C. Hydro's, and other publicly owned corporations, economic development activities and strategic plans.

Other regulations govern development and operation of hydroelectric and other components of the power systems operated by electric utilities in British Columbia. On the hydroelectric generation operations side, environmental regulations includes the Fisheries Act which is concerned with post construction impacts on fish and fish habitat, and the Water Act, which is concerned with hydroelectric water allocations and operating requirements. Other regulations are in the form of water rental fees and water license. Water rental fees are paid to the provincial government and are based on plant capacity, energy generated, area flooded by reservoirs, volume of reservoirs and other items. The water license is granted to B.C. Hydro by the Comptroller of Water Rights of the Province of British Columbia to store and/or use water for generation of electricity.

As with other utilities around the World, electric utilities in British Columbia are vertically integrated, with responsibilities for generation, transmission and distribution, and customer services. To explore effects of the emerging competitive market on the future structure of the electric industry in British Columbia, and the alternatives to meet these emerging challenges, the Provincial government has requested BCUC to conduct a review of the electricity market in B.C. The review was published in 1995, and included recommendations on separation of operating divisions in publicly-owned electric utilities in British Columbia, and promotion of the idea of the wholesale pool model accompanied by measures to ensure continued inclusion of environmental and social considerations. The review rejected the idea of retail competition (full competition) as an option for British Columbia's future electricity market and deemed it unnecessary at the time (BCUC, 1995). Soon after publication of the review, the Provincial Government (represented by the Minister of Employment and Investment) appointed Mark Jaccard (Chair and CEO of BCUC), as advisor, to lead a task force to bring "forward to government a package of electricity market reform proposals, including legislative changes if necessary" (Jaccard, 1998). The terms of reference for the Task Force were very restrictive, in that it did not allow them to explore the full range of possible alternatives available. They were mainly constrained by the following (Jaccard, 1998, p. 7):

- "continued public ownership of the assets of B.C. Hydro,
- no negative impact on B.C. Hydro's dividends to the province (water rentals, dividends, taxes, grants in lieu of taxes),
- no adverse effects on specific classes of customers or customers in particular regions,
- no adverse effect on electric sector employees."

Although the government's appointed Stakeholders on the Task Force were unable to reach consensus on the basic components of electricity reform in B.C., Jaccard issued his "Reform Proposal". The proposal calls for the electric industry in British Columbia to be reformed in two phases, and classified four major evaluation elements for the proposals: customer access, market structure, social concerns, and environmental concerns. Of particular interest to this thesis is the proposed reform's effect on customer access and market structure in B.C. In the first phase (by January 1999), Jaccard's proposal allows for 50% of industrial customers to pursue other generation suppliers, with the option of staying under the B.C Hydro's and West Kootenay Power's tariff system. In phase two (by January 2001), all industrial customers, and possibly commercial customers could pursue such opportunities. All other customers would remain under the regular utility tariff system.

The proposal also reformed the B.C. electricity market structure by further separation of the transmission, distribution and generation functions from grid-related, common carrier functions that include: system operation, transmission planning, and transmission tariff. This de-integration aims at prevention of the use of transmission market power that B.C. Hydro's currently enjoys, and is a pre-requisite for access to California's and other (emerging) markets in the U.S. The proposal also recommended that the transition be carried out in two phases: phase one includes establishment of a Grid Oversight Committee and B.C. Power Exchange. Phase two would establish a new B.C. Grid Company that takes over the committee's functions, the de-integrated B.C. Hydro's Transmission Business Unit, lease the West Kootenay Power's grid related assets, and operate the B.C. Power Exchange. All of the newly created and de-integrated entities are to remain publicly owned and regulated by the BCUC.

Analysis of the reform proposal leads one to conclude that the regulator is trying to expand his jurisdictions and get involved in the micro-management of utilities. As stressed by B.C. Hydro's Senior Vice President for Transmission and Distribution in 1995, the role of regulators will have to change in competitive market structures from that of expanding jurisdiction and micro-management to streamlining and expediting reform processes (Threlkeld, 1995). Repercussions of the Jaccard proposal are still to be seen. In the meantime B.C. Hydro has been restructured into three separate business units: Power Supply, Transmission and Distribution, and Customer Service. The main aim of restructuring into three business units is to enable B.C. Hydro to identify the specific, separate costs and values of their service. Once the costs are known for each service function, informed judgments about prices for the services they provide can then be made (Threlkeld, 1995). In addition to restructuring, several efforts are underway to prepare the organization for the transition to any possible market structure, as discussed in iii below.

ii. Forces of Change in the Electric Industry

As discussed above, the formal structure of the market in B.C. is not yet clear, as there are many forces at play, but most utility executives agree that early in the new millenium, North America will have a deregulated fully competitive electricity market. The electricity market is forecast to be the largest commodity market with annual sales estimated in the U.S. at US$300 billion (Douglas, 1997). As the electric power industry continues to rapidly change, it is believed that the traditional monopolistic environment will inevitably make way for increased competition, both in the wholesale and retail levels. As emphasized by Navarro, sooner or later, cautious utilities, and their regulators, will have to adopt radical restructuring, preferably before retail competition comes to their own backyard (Navarro, 1996). This view, however, did not go unchallenged as expressed by Khun (see for example Khun et al., 1996).

Forces of change in the electricity industry have been attributed to three major factors: changes in electricity generation technology, globalization of the economy, and changes in public policy (BCUC, 1995a, BCUC, 1995b). For more details see also Weiner et al. (1997). It is widely believed that these changes could result in considerable savings, particularly for large industrial and commercial users.

Locally, the drivers for change are believed to be somewhat different and they stem from four main factors (Jaccard, 1998):

- demand of neighboring competitive markets (e.g., California) for reciprocal reforms in B.C. to assure level competition ground;
- desire of B.C. customers to participate in future electricity supply investment and to assume the risks involved;
- desire of B.C. customers to have access to market-based electricity purchase options; and
- desire of IPPs and electricity marketers to have fair access to customers in B.C.

iii. Currents of Change for B.C. Hydro

The future of the power industry in British Columbia is uncertain, and the timetable for deregulation has not been set yet. However, there are several major indicators of the ongoing trend of increased competition, particularly for B.C. Hydro (B.C. Hydro, 1998c, BCUC, 1995):

- PowerEx established in December 1988,
- BCUC rejected BC Hydro's proposal for industrial rates and denied other provisions for new services in April 1992, and later (after a public hearing process) BCUC recommended granting BC. Hydro and PowerEx an Energy Removal Certificate for short-term electricity trade. In September 1992 the government granted PowerEx the Energy Removal Certificate.
- In October 1992, the province issued a policy encouraging the development of IPPs for domestic supply with the project evaluation based on Social Costing Principles.
- The Ministry of Energy, Mines and Petroleum Resources issued a Long-Term Firm Electricity Export Policy in July 1993.
- In December 1994, the provincial government announced that B.C. Hydro will issue a Request for Proposals for 300 MW of electricity from the private sector.
- In December 1994, BCUC was directed by the government to hold a public review of electricity market restructuring in B.C.
- In Sept. 1994, the Province signed a Memorandum of Understanding with U.S. authorities for the next 30 year delivery of the downstream benefits of the Columbia, and in 1995 the Province and the Columbia River Treaty Committee signed the Columbia Basin Accord creating the Columbia Basin Trust to oversee the region's share of downstream benefits. The intention was to jointly develop new or to expand hydropower production at three existing dams: Keenleyside, Waneta, and Brilliant. The government

legislated that sales from these developments are intended for new and expanding industrial customers.

- Early in 1996, B.C. Hydro received a wholesale transmission tariff and a Real Time Price (RTP) tariff to allow industrial users to buy directly from the market under certain circumstances. The move is aimed at meeting the reciprocating demand for comparable access by the U.S. Federal Energy Regulatory Commission (FERC).
- In January 1996, Alberta implemented a Poolco[1] model, which created the Alberta Power Pool for electricity trade. Alberta is currently working on a reform to retail competition.
- In 1995, a large hotel in Vancouver announced their plans to install a gas generator. Other hotels, and a university in B.C. are considering doing the same (Threlkeld, 1995). In October 1996, the West Kootenay Power offered a power service contract (EnergyOne) to Surrey Memorial Hospital.
- In December 1996, B.C. Hydro industrial customers requested retail access that enables them to shop around for better prices.
- In January 1997, B.C. Dan Miller announced that B.C. Hydro's monopoly over electricity in British Columbia would end.
- In September 1997 FERC approved PowerEx's application for a power marketing certificate to access U.S. markets.
- In November 1998 B.C. Hydro real-time pricing for industrial customers was approved by the Provincial Government.
- In January 1998 Mark Jaccard published his report on electricity market reforms in British Columbia (Jaccard, 1998).

To take advantage of the competitive environment, B.C. Hydro has realized that they must operate their system to maximize the value of their resources at the various levels of planning for power supply operations. Several steps have been taken to achieve this objective including restructuring the organization to meet the emerging challenges and implementing new business processes. The Business Transition Program was initiated with the vision that the Power Supply (PS) Business Unit of B.C. Hydro compete profitably in any future energy market structure. To realize this vision, the following functional projects have been initiated (B.C. Hydro, 1998c):

- **Asset Management** (AM), which provides costs of operation and revenue potential from making B.C. Hydro's energy resources commercially available;
- **Operational Information** (OI) objective is to maximize operating efficiencies by implementing a software tool that monitors near real-time and historical information on generating units, plants, and river systems operations;
- **Commercial Resource Optimization** (CRO) is aimed at providing an integrated set of decision support tools to achieve optimal commercial use of water and other fuel resources;
- **Commercial Management** (CM) is aimed at communicating plant capabilities, production, revenue and cost performance to B.C. Hydro's operating staff with the objective of maximizing profit potentials;

[1] Under the Poolco model, buyers and sellers are not free to negotiate prices and terms directly with one another, and they are restricted to buy and sell power from a centralized pool. While no bilateral agreements were allowed, participants were allowed to enter what is called Contracts for Difference (CFD's).

- **Coordination with Marketing and Customer Services** (M&CS), which aims at increased coordination between Power Supply and Marketing (primarily PowerEx) business units;
- **People Change Management** (PCM), which aims at determining the effects on B.C. Hydro, training needs, and to help to bring about successful cultural change;
- **Information Technology** (IT), which aims at enhancing availability of information systems (such as the SCADA and PI systems);
- **Working for Profitability** (WfP), which aims at enhancing the business awareness and practices of Power Supply's employees.

Of particular importance to this thesis is the Commercial Resource Optimization project (CRO). Among the components of CRO are the following (Taylor, 1998):

- **Hydromet Data**, which aims at improving the hydrometerological data collection network and modernizing the database and procedures used to store and analyze hydrologic and meteorological data.
- **Large Reservoir Optimization**, which aims at enhancing the Williston Marginal Cost Model, complete the Columbia River Marginal Cost Model, and develop an economic modeling framework and understanding of model drivers and sensitivities to increase confidence in using the results of the modeling for operations and trading decisions;
- **Short Term Models**, which will focus on developing Static Plant Unit Commitment (SPUC) and the Dynamic Unit Commitment (DUC) models and further development and integration of the ***Short Term Optimization Model*** (developed by this thesis) with other CRO models. As will be described in Section 4.5, SPUC has been extensively used by this thesis to prepare the plant's production curves. In addition, the author, and other researchers from UBC are actively participating in setting the user's requirements and algorithms for DUC. Both SPUC and DUC are forecast to further improve efficiency of operation of the B.C. Hydro system, and eventually will be used by the Shift Engineers in their daily operations. It should also be noted that development of the Short-term Optimization Model (STOM) was started before the CRO project was conceived, and was subsequently added to become one of the CRO project's main components;
- **CRO Database**, which will incorporate facility and system constraints into real-time and short-term optimization modeling along with market values for all products and services offered by B.C. Hydro. The constraints database includes physical generating plant and unit characteristics and operational and other constraints. The author of this thesis has been actively engaged in promoting the idea for the potential use intelligent systems (such as expert systems) to process and interpret the system constraints;
- **Model Integration Framework**, which will design and build the databases and procedures required for integrating models and data together. The author of this thesis has been actively contributing to development of some aspects of the model integration framework, particularly with issues regarding integration of the Short Term Optimization Model within the overall modeling framework at B.C. Hydro.

The expected benefits from implementing the CRO project are estimated by B.C. Hydro to total $25 million per year, of which the ***Short Term Optimization Model is expected to contribute about $5 million per year***.

3.2 THE BC HYDRO DECISION-MAKING ENVIRONMENT

As indicated in Chapter 2, over the last seventy years researchers and practitioners have devoted considerable effort to develop techniques that can be used at one or more of the levels of operational planning of hydroelectric and thermal facilities. The aim of developing such techniques and methodologies was to arrive at an integrated approach that could be applied to both the long and short-term operation of hydroelectric facilities. Such an approach is, however, still under development as there is no one standard methodology that has been agreed upon by researchers and practitioners as yet (Wood et al, 1996). There are several reasons for this. First, every system is unique in terms of its size and the configuration of the managed facilities. For example most systems contain a variable mix of hydro and thermal generating facilities. Second, the organizational culture of each management entity is different and is governed by different internal policies, legislation and regulation and operating environments. Third, and as result of the ongoing deregulation move of the electricity industry, the market structure is different for each participant in terms of the size of the market and its major players.

Given the above reasons, and the current state-of-the-art of the methods and techniques, each entity will have to adapt an approach from the pool of appropriate methodologies for use in its operations planning to suit the prevailing environment. In this regard, B.C. Hydro has embarked on a process to develop a set of operational planning models to be used in their daily operation activities. But before addressing the operational planning models that B.C. Hydro currently use or plan to use, the changing decision environment is described to give "a feel" for the context.

3.2.1 Guiding Criteria for Decision Making

Making operating decisions for a large-scale hydroelectric system involves a wide spectrum of issues ranging from the safety of lives and property to the efficient operation of generating facilities. Operation of B.C. Hydro's system is guided by the following criteria (B.C. Hydro, 1993):

- safety of lives and property;
- regulatory requirements, such as water license and government legislation;
- obligation to meet present and future power demand;
- balanced tradeoff between economic and environmental requirements;
- technical efficiency;
- reliability and security;
- economic efficiency;
- responsiveness to the changing demands of customers.

The above list is not exhaustive, but is intended to illustrate the extent and complexity of the operating environment (see for example Keeney and McDaniels 1992). Decisions also depend on prevailing societal values. For instance, decisions to build the large-scale hydroelectric facilities in British Columbia were made at the time when societal values emphasized cost, efficiency and the creation of an industrial infrastructure base (B.C. Hydro, 1998a). In addition to the above criteria, the other factor that is gaining increasing weight in decision-making processes is the type and structure of the market where electricity is sold.

3.2.2 *Objectives of the System Operator*

In traditional monopolistic, vertically integrated, electric utilities, the main objective of the hydroelectric system operator is to secure a stable supply of electric power to meet the firm domestic load demand and firm trade transactions, while meeting the system's physical and operational constraints. The major driving force in making operating decisions is to ensure the availability of sufficient energy and capacity to meet the system demand, while meeting non-power requirements and operational constraints. The electricity industry across North America, and in many parts of the world, is changing very rapidly -monopolies are being deregulated and competition is evolving. The emerging competitive market structure in the electric power industry is affecting the various levels of the traditional strategic and operational decision-making processes (BC Hydro, 1998b). As deregulation of the power industry proceeds, competition is causing a major shift in the way generating facilities are managed. The emphasis now, and in the near future, will be on more effective operation of existing facilities to maximize the value of resources while meeting the operational constraints. In other words, a shift in paradigm is already underway to manage resources in a business-like manner. This is reflected clearly in BC Hydro's new statement on their strategic objectives (BC Hydro, 1998b, p. 8):

"Strategic Objectives

Lead the market

- ***Retain and grow profitable market share in existing and emerging competitive markets***
- ***Efficiently and creatively meet customers needs and expectations in all markets***
- ***Build a strong and capable organization***
- ***Ensure our people have the skills, tools, and environment required to achieve our vision and mission***
- ...

Increase financial efficiency and productivity

Ensure effective governance

Build and maintain public support"

These objectives are in contrast to B.C. Hydro's corporate objectives just few years ago (BC Hydro, 1994):

- ***"To be a leader in the economic and social development of British Columbia***
- ***To be a leader in the stewardship of the natural environment,***
- ***To be the most efficient utility in North America***
- ***To be a superior customer service company,***
- ***To be the most progressive employer in British Columbia."***

Strategic objectives, if properly formulated, should be "structured to provide insight into how analysis should proceed in decision contexts" (Keeney and McDaniels 1992). Given B.C. Hydro's statement on their new strategic objectives, it is evident that several changes in their decision-making processes are, or soon will be, underway. These changes are aimed at transforming the organization to be more responsive to emerging needs of the new deregulated operating environment. Operating under such new environment, however, will require decisions to be based on consistent and reliable approaches.

3.2.3 *Generation System Operations*

The B.C. Hydro's Power Supply Business Unit plans and operates the generation facilities to meet the domestic load obligation and to maximize the value of resources while meeting the environmental commitments and other physical and operational constraints imposed on the system. The planning function is focused on the following activities (personal communications):

- Produce facility operation plans;
- Coordinate generator maintenance schedules;
- Prepare detailed weather and inflow forecasts;
- Prepare short-term load forecasts;
- Arrange gas supply for the Burrard generating station;
- Determine the marginal value of B.C.Hydro's energy;
- Determine longer term marketing capability and requirements;
- Coordinate B.C. projects operation under the Columbia River Treaty;
- Manage West Kootenay Power Agreement; and
- Manage Independent Power Contracts.

Generation scheduling is concerned with the activities to implement operations plans, to ensure load-resource balance and to determine the short-term and real-time electricity trade capability and requirements. It also directs operation of the generation and storage facilities to minimize flooding potential. In addition, the system is operated to fulfil B.C. Hydro's power agreements and treaties with other concerned agencies (nationally and internationally). Other functions include management of non-power needs, such as balancing power generation requirements with the needs of fish, wildlife, recreation, and flood control. They are also responsible for implementing strategic fisheries research and more recently preparing Water Use Plans.

The main concerns of system operations, however, are electricity demand and water inflow. As the demand for electricity and water inflows are beyond the control of the system operator (to a great extent both depends on the weather), the generating system is operated to satisfy the firm domestic load, to minimize operating costs, and to protect consumers from electricity shortages during periods of low water flow in dry years. On the other hand, when water is in abundance, system operations are focused on making the best use of available resources to maximize profits. To operate the generating system reliably two conditions must be met: sufficient energy capability, and sufficient peak capacity. Energy capability refers to the average amount of electricity produced under all stream flow conditions over a given period (e.g., one year or in a day). Peak capacity refers to the maximum rate at which electricity can be produced at any given time. The goal of providing sufficient energy capability is to be able to match energy demand at all times, while the goal for providing sufficient capacity is to enable the system to meet instantaneous peak power loads. A complicating factor in meeting these goals is the fact that the demand for electricity and water inflows are both uncertain, as both primarily depends on weather conditions. For this reason, system operations must also take into account errors in forecasts of demand and inflows (short and long-term). In addition, special provisions must be allowed for unforeseen facility outages and long and short-term system dynamics. More recently, and due to deregulation, system operation must also make a balanced tradeoff between system operations reliability (energy and capacity) and opportunities in the market place, in the long as well as the short-term.

Inflows to the majority of reservoirs operated by B.C. Hydro are characterized by low flows during the winter and high flows during the snowmelt season in the spring and early summer. To illustrate the seasonal variability of inflows in the B.C. Hydro system, Figure 3.4 shows flows of the Peace River into the Williston reservoir, and Figure 3.5 illustrates flows of the Columbia River into the Kinbasket reservoir. Demand on the other hand is high during winter and low during summer, and it fluctuates during the hour of the day, the day of the week, and the month of the year. Figure 3.6 illustrates the variation of daily total demand during the past 13 years, and Figure 3.7 illustrates the hourly maximum and minimum daily demand for the same period. Figure 3.8 illustrates the variation of the maximum, minimum, and average hourly demand in 1997, while Figure 3.9 illustrates the variation of domestic hourly demand.

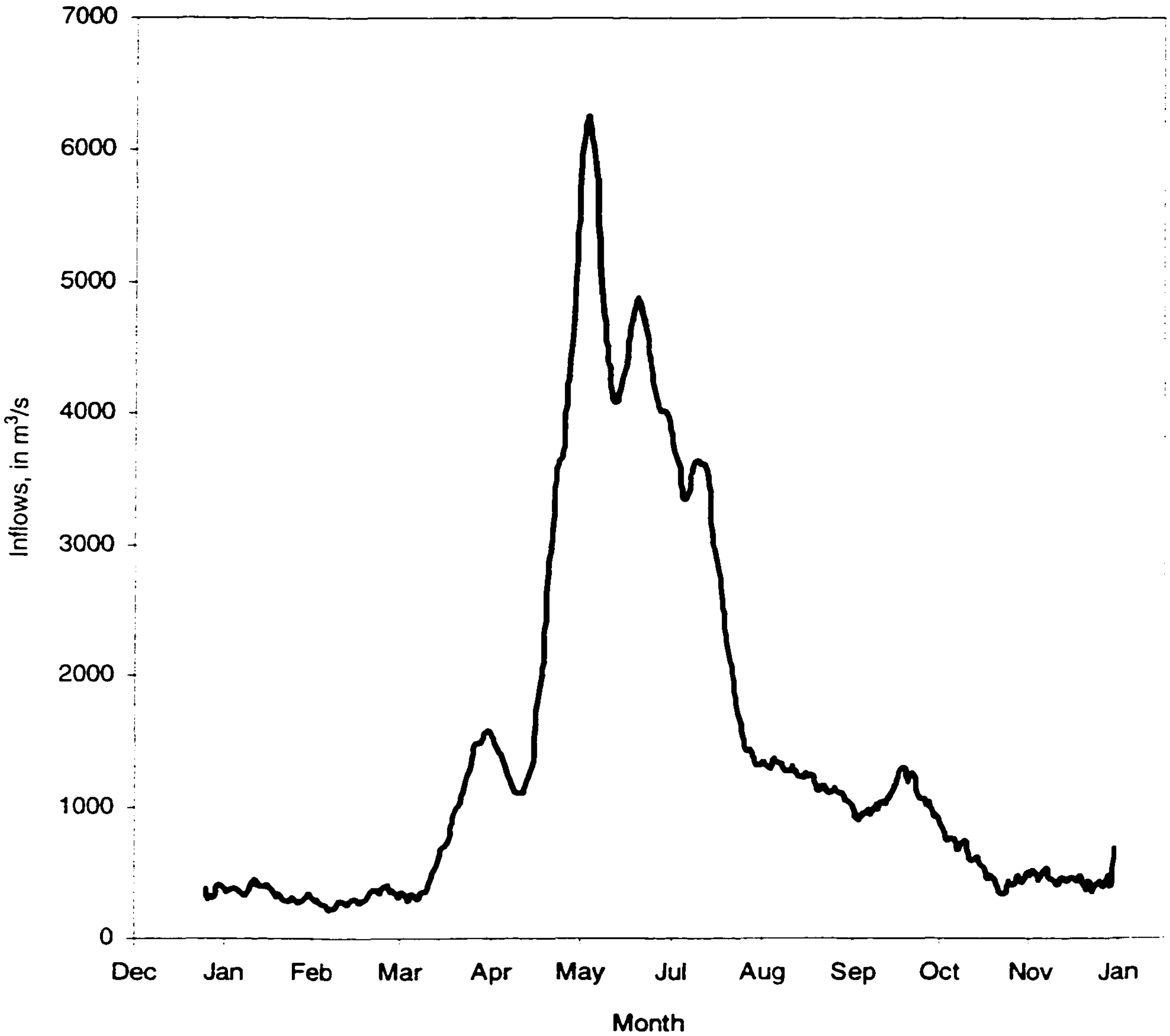
The system's storage reservoirs are used to regulate flows during high inflow periods for use during high demand periods. In addition, and as generation capacity depends on the head of the water column on the turbines, storage reservoirs must be operated to ensure that there is adequate head to meet the capacity reliability criteria. In hydroelectric systems, spills from reservoirs are not desirable. Spills usually occur for two reasons: obligatory requirements (environmental, legal, or operational); or uncontrolled spills. Under the first condition, the system is operated to satisfy the obligatory requirements, while the second occurs due to the inability of the system to provide sufficient storage, generation, or transmission capabilities to store or use the excess flows. These capabilities prevent the system operator from fully exploiting the surplus energy that could be stored, generated and sold in the market place. Conversely, when inflows are low, system operations must augment energy supplies by drafting large storage reservoirs, use available thermal generation to supplement hydroelectric supplies, or import electricity from other power producers connected to the B.C. Hydro transmission network in B.C., Alberta, or the U.S. Under all circumstances generation system operations ensures that enough water energy is stored in reservoirs, or enough transfer capability is available to meet the firm domestic load from the available sources. The later is particularly important since the transfer capabilities between the B.C. Hydro system and the neighboring systems (Alberta and the U.S.) are limited by the tie line capabilities, which could be fully booked during peak load instances.

Figure 3.10 depicts the annual flow of water into and out of a typical reservoir. From January to May, the reservoir is being drawn down, because this is the dry season, and water required for generation exceeds inflows, and by May storage reaches its lowest level. For a well-planned and well-operated system in a normal year, the reservoir at this time of year will be at its minimum operating level, containing only a small safety reserve margin of water. From May to October, the wet season begins during which water inflow from the catchment area exceeds the desired outflow. The reservoir fills up between May and sometimes before October when the reservoir reaches the maximum storage level and starts to spill. Spilling ceases as the reservoir is drawn down and the dry season starts again. This annual cycle continues for the next year and so on.

The B.C. Hydro system is composed of several reservoirs, in different regions across the Province. System operations engineers determine how each generating facility should be operated to satisfy the hourly demand, to manage reservoir operations so that future demand can be met, system efficiency and economic returns are maximized, and that all environmental, legal, operational, and physical constraints are respected. This is an extremely complex task with many tradeoffs to be made. The main tradeoffs are between efficiency, security of generation and the risk of spilling (or keeping the reservoirs at high or low levels). If reservoirs are kept at high levels, more generation will be achieved from the same amount of water (because of higher head), with more secure supply of electricity. However, the risk of spills, with the loss of potential energy and flooding, will be higher. High spill levels can cause considerable environmental and physical property damage (and sometimes loss of life), and Bc Hydro has to provide mitigation costs and measures. Low reservoir levels, on the other hand, result in less generation from the same amount of water (because of lower head), less secure supply of future electricity, and a lower risk of spill and flooding. The entire system, then, must be coordinated to achieve optimal or near optimal operation. The optimal operation must take into consideration: inflow conditions, electricity demand characteristics, electricity market conditions (both long-term and short-term commitments), system status, maintenance requirements, specific dam and generating facilities constraints, uncertainties in forecasts (inflow, market, and demand), and unplanned facility outages.

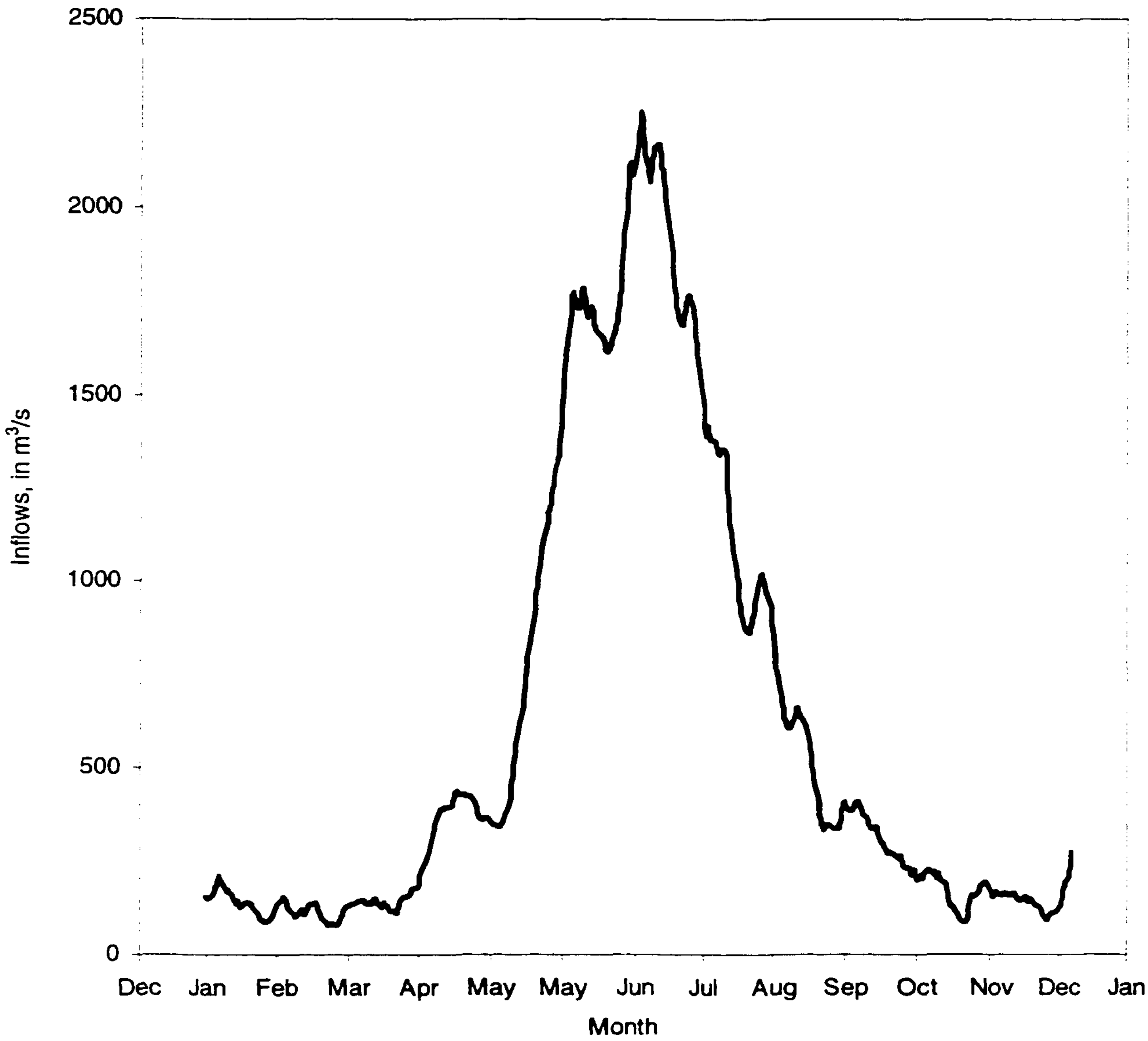
The other major challenge is to balance generation between many river systems under the control of the system operator. Seasonal and annual inflows may be high in one river system and low in the other. An attempt is required to balance the output from various generating facilities to account for different inflow conditions while meeting total generation requirements. The decision to increase generation in a river system propagates throughout the system and affects other generating facilities in other regions. For example, if inflows to the Bridge River system are high and spills are likely, generation would increase in the Bridge system and be reduced in other systems.

It is obvious from the above discussion that continuous planning must be an integral part of the duties of the Power Supply Business Unit at BC Hydro. Due to the complexity of the task, operations planning is carried out at four different levels: long-range (investment), long-term (operational), short-term, and real-time as will be discussed below.



Source of information: Resource management, B.C. Hydro, 1998.

Figure 3.4. Daily Average Peace River Inflows at Williston Lake, 1996.



Source of information: Resource management, B.C. Hydro, 1998.

Figure 3.5. Daily Average Columbia River Inflows at Kinbasket Lake, 1996.

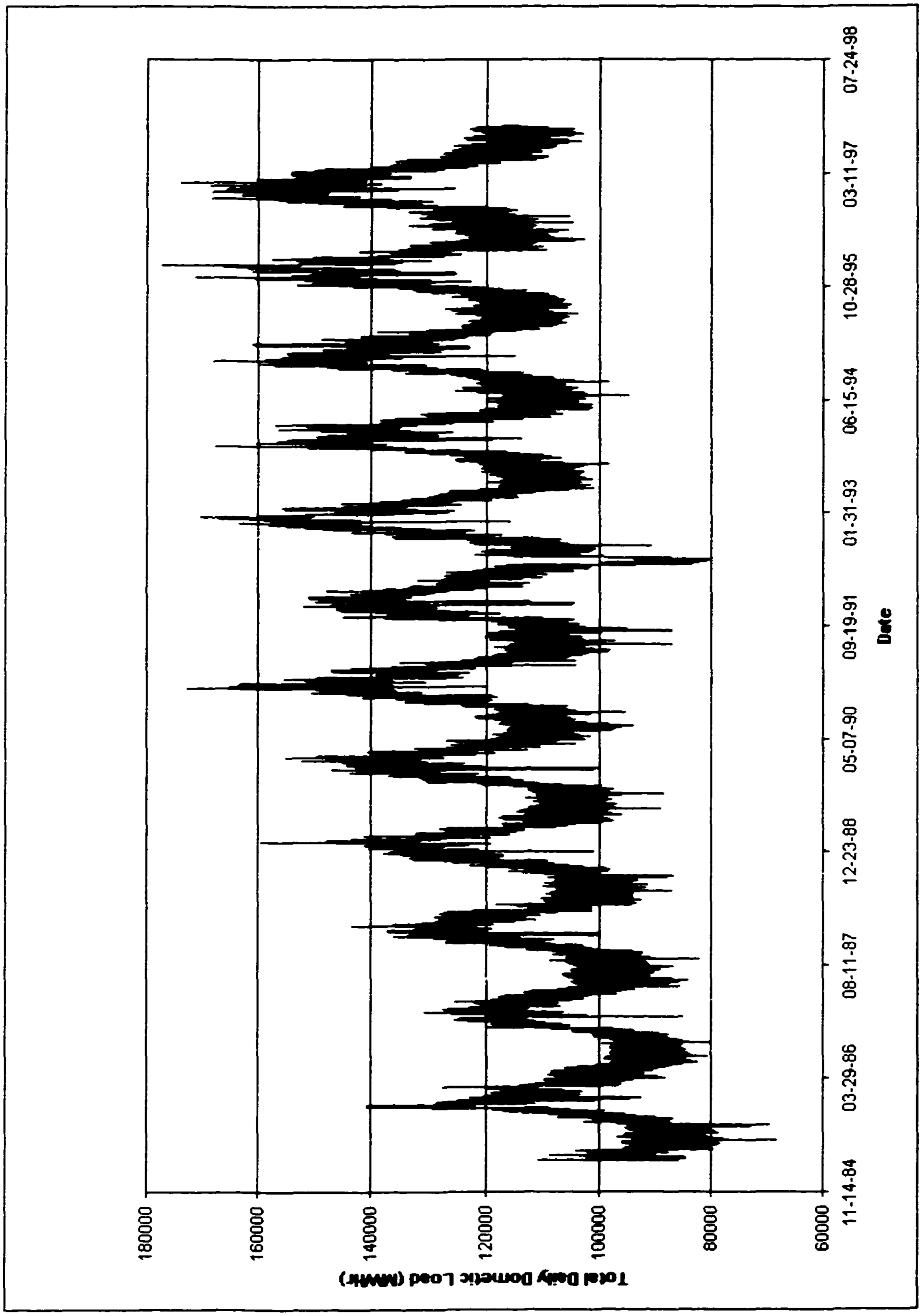
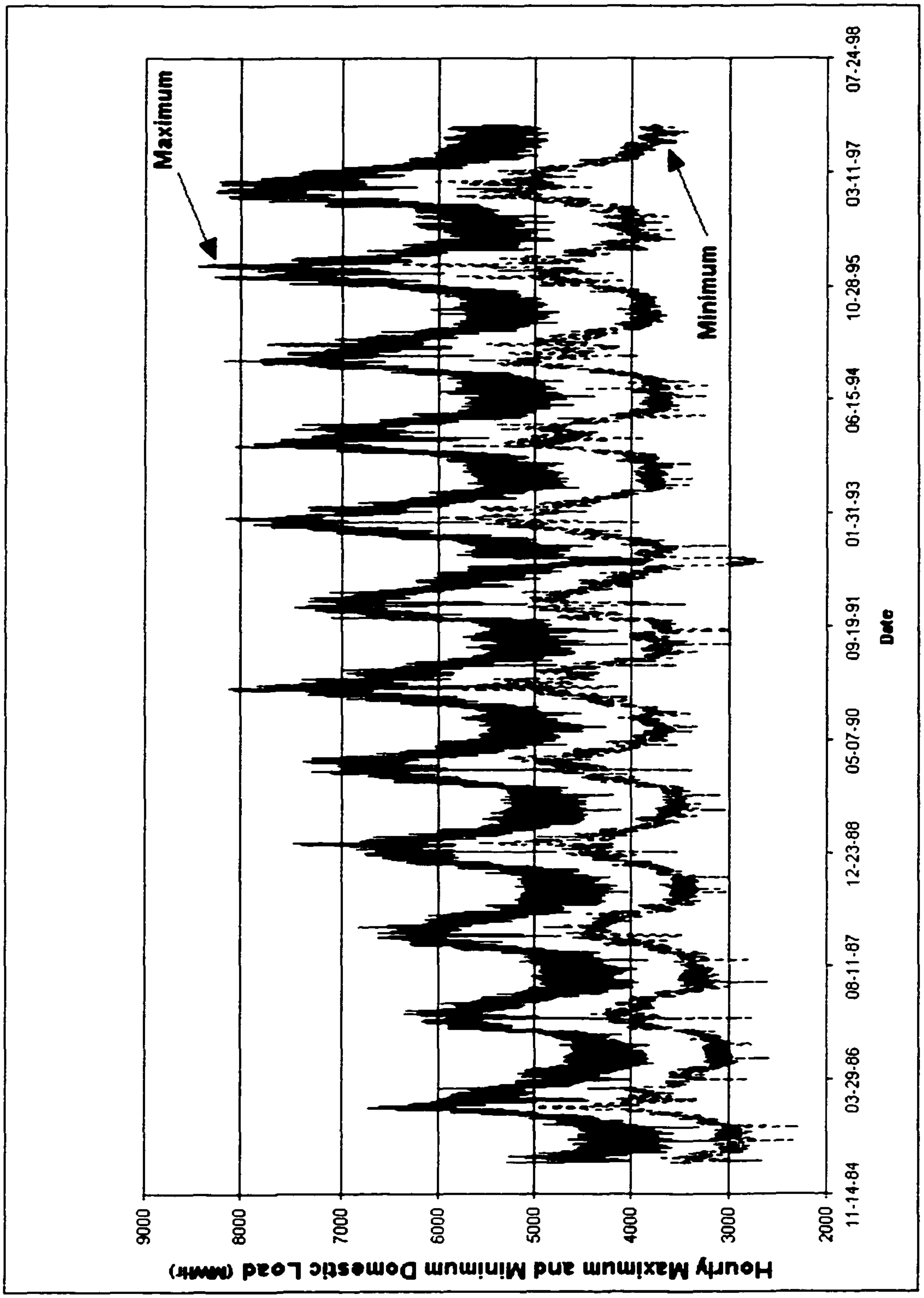
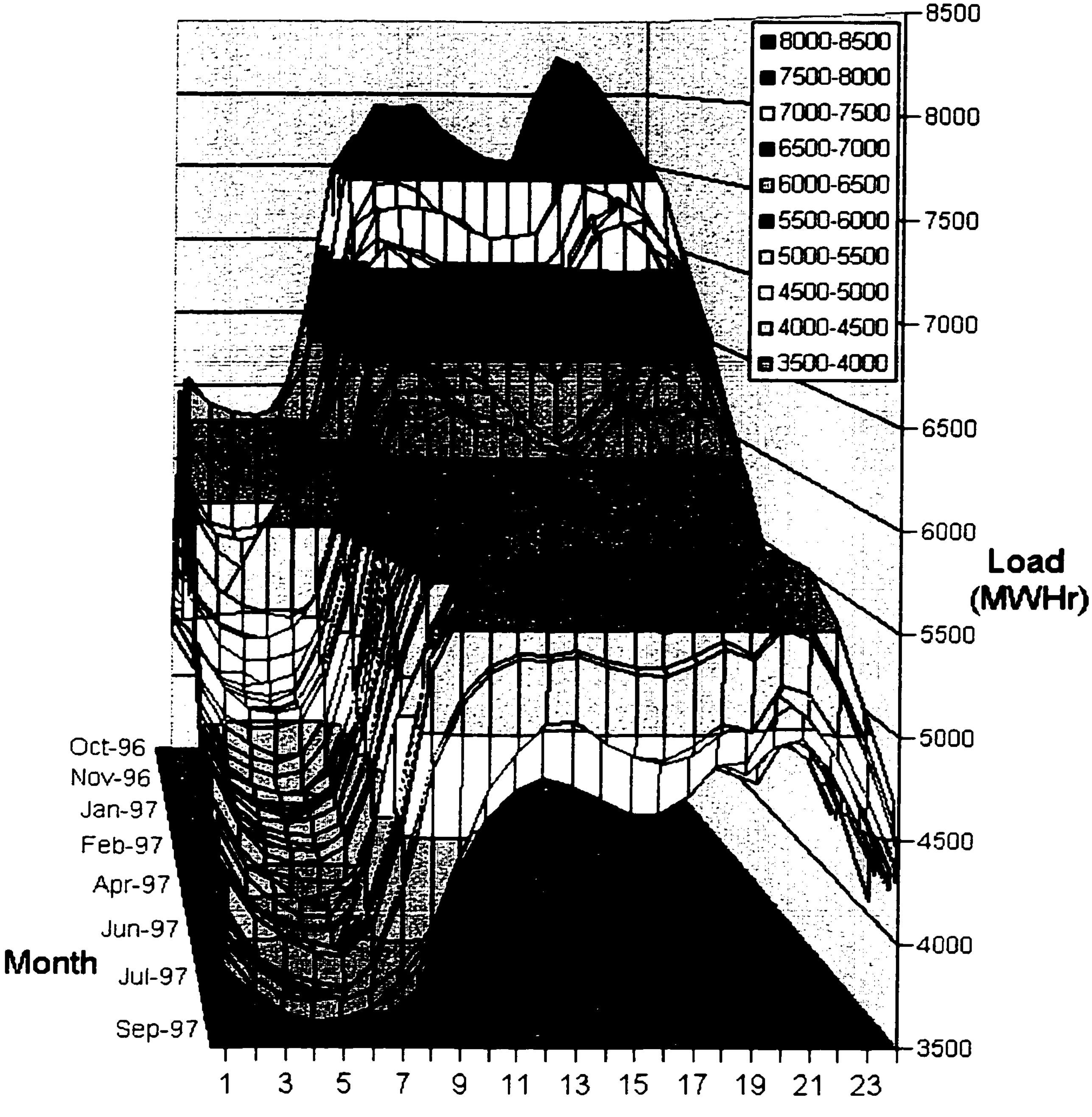


Figure 3.6. Total Daily Domestic Load (1985-1997).



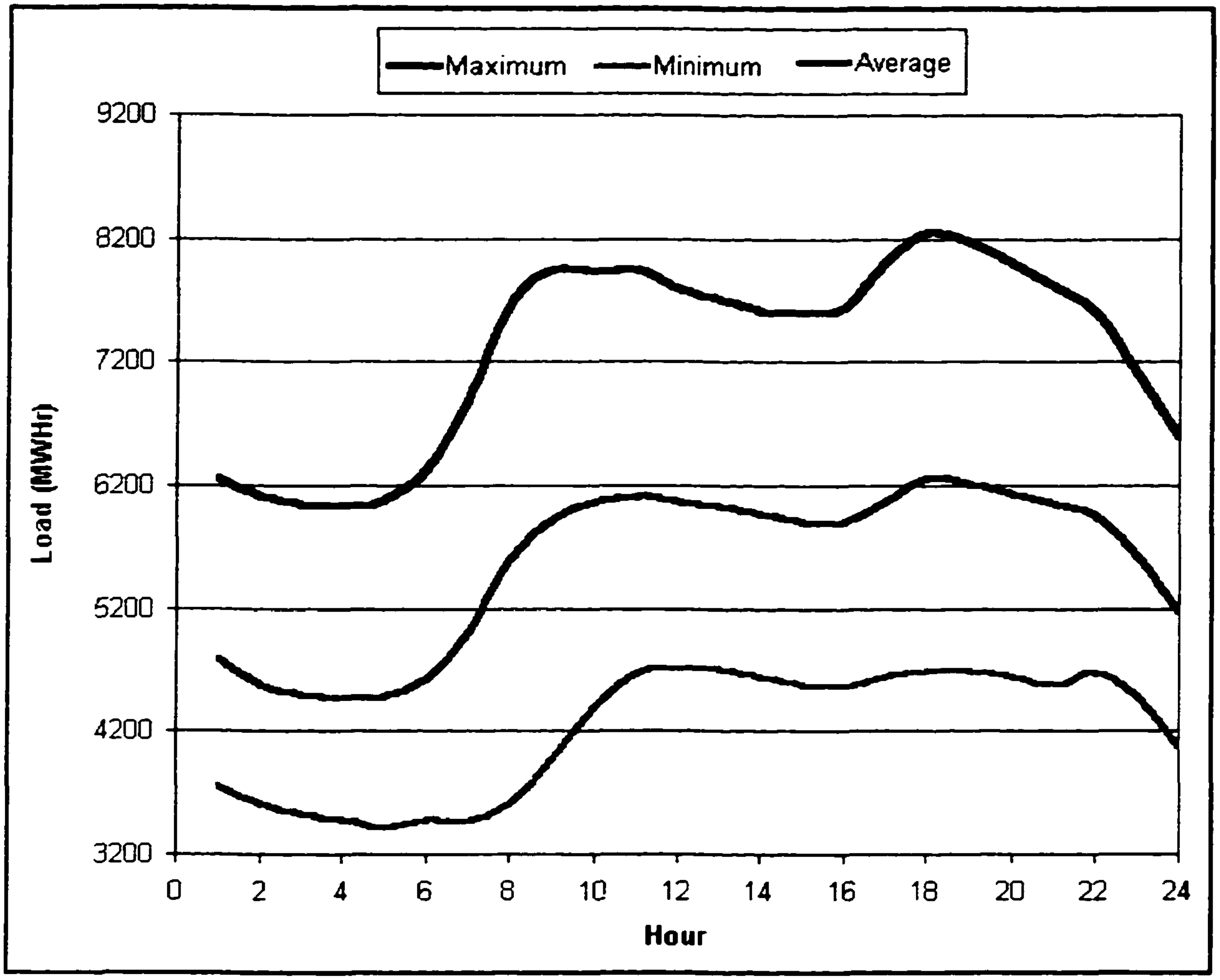
Source of data: BC Hydro, Resource Management

Figure 3.7. Minimum and Maximum Hourly Load (1985-1997).



Source of data: BC Hydro, Resource Management

Figure 3.8. Variation of Monthly/Hourly Domestic Load in 1997.



Source of data: BC Hydro, Resource Management

Figure 3.9. Variation of Hourly Domestic Load in 1997.

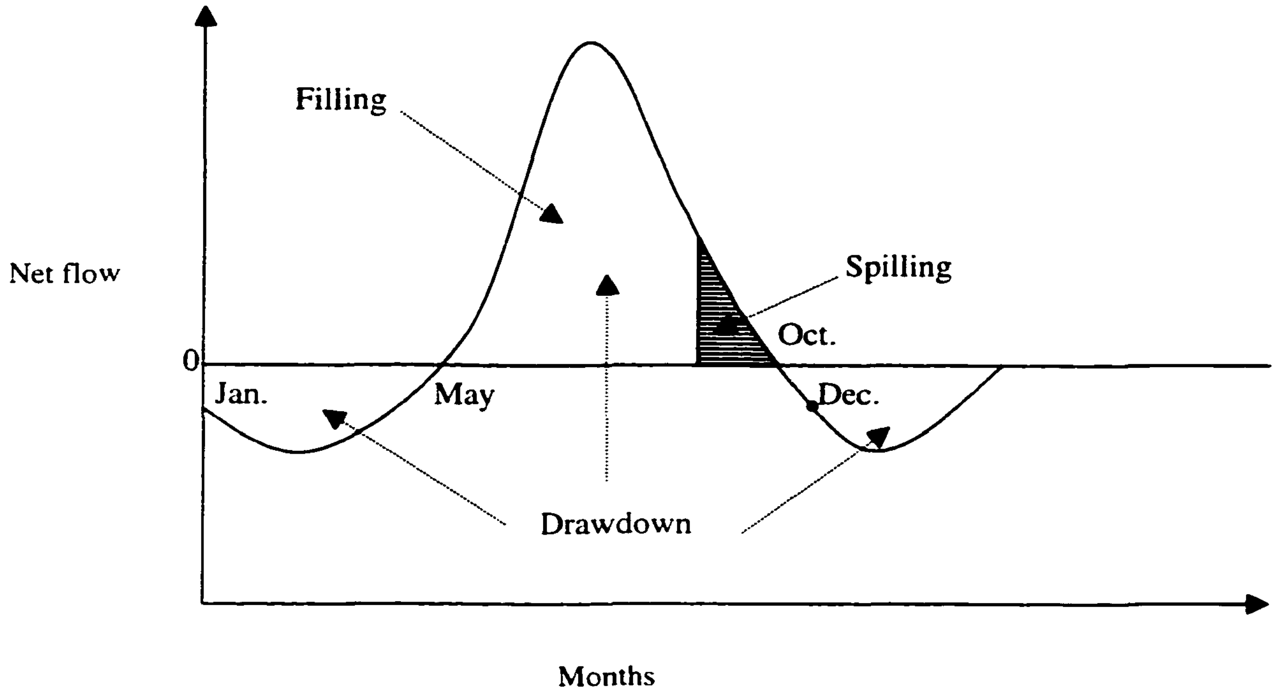


Figure 3.10. Filling and Draw Down of a Typical Storage Reservoir.

3.2.4 System Operations Planning

B.C. Hydro has been performing optimization studies for over 25 years to maximize the efficiency of their operations. As with other utilities in Canada (Acers, 1994), B.C. Hydro's optimization studies have dealt mainly with the long-term at the strategic level (Druce, 1991). Short-term operations did not receive much modeling attention until recently, but relied on the skill and long experience of the operating staff. The following sections outline the main features of the approach currently utilized by B.C. Hydro for system operations planning.

i. Aims and Guiding Criteria for Operations Planning

The aim of planning is to account for many factors that can affect the day-by-day and long-term supply of electricity. The factors can be summarized as follows (BC Hydro, 1993):

- electricity demand forecasts;
- inflow forecasts;
- reservoir levels;
- turbine and generator restrictions;
- security of supply requirements;
- transmission network constraints;
- fishery requirements;
- flood control requirements;
- Columbia River Treaty obligations;
- reliability considerations;
- efficiency considerations; and
- maintenance requirements.

The planning process is guided by specific criteria in the following order of importance (BC Hydro, 1993):

- safety of lives and property;
- regulatory requirements;
- need to meet present and future power demand;
- balance between economic and environmental requirements; and
- efficient operation.

To plan operations in a conceptually correct manner, the Power Supply operations planners are currently in the process of developing an economic framework for the Power Supply Business Unit (personal communication with Mr. K. Ketchum). The economic framework relies on the use of price signals to guide their operations. These price signals are derived from optimization models described in "iii. Planning Levels". One of the basic ideas behind the economic framework under development is to pass the computed value of water, as derived from optimization models at each planning level, to models at lower levels in the modeling hierarchy as illustrated in Figure 3.11. This is believed to best approximate optimal operation of the entire hydroelectric system. STOM takes this economic framework into consideration by incorporating the price signals into its objective function as will be detailed in section 4.5. STOM assumes that the price signals are available and are one of its user's input (see Section 4.3.2 for details), however, the author believes that much research work still needs to be done to put the economic framework's concepts into operational reality.

ii. Data for Operations Planning

To perform credible planning studies, much information is currently utilized (discussion will be focused on data relating to the current subject matter of this thesis). The items are briefly discussed in the following sub-sections.

a. Weather and Inflow Forecast

The hydrology section employs a meteorologist and hydrologists to forecast the weather and reservoir inflows both for the short and for the long term. The hydrology section operates an extensive network of hydrometeorological stations across the Province to gather climate, stream flow and snowpack information and use them to forecast weather and inflow patterns. It has access to a state-of-the-art real-time weather forecasting system that employs sophisticated weather and hydrologic models. Some of the weather models (e.g., wind flow models) have been developed and run in cooperation with the University of British Columbia's Geography Department. In addition, the satellite imagery system continuously updates information on the weather systems affecting the various regions in British Columbia and that could potentially affect reservoir operations. Future plans include the use of Doppler Radar systems to improve forecasting of severe localized weather systems.

The hydrology section forecasts expected reservoir inflows and produces seasonal as well as five-day forecasts. For some river basins, the hydrology section utilizes the U.B.C. Watershed model, developed at the Civil Engineering Department, U.B.C. Current efforts are underway to use this model for the majority of river basins managed by B.C. Hydro. Historic inflow records are also maintained and are calculated from the reservoirs' recorded water levels and actual generation schedules and spills. For use in planning studies, these records are screened and corrected for errors in calculated historic daily inflows (Druce, 1996).

b. Domestic Load Forecast

Load forecasting is performed at various levels of the planning process. Long-term load forecasts are performed at the Planning Department, while short-term load forecasts (next few days) are calculated by the ANNSTLF neural network model (Khotanzad et al., 1997). Load forecasting for the next hour is determined heuristically by the Shift Engineer, with the aid of ANNSTLF and a simple Excel spreadsheet model that calculates the 5-minutes moving average from recorded load information relayed from the T&D System Control Center.

c. Generating Unit Outages

Generating unit outages affects the system and plant generating capacity. In close coordination between planning engineers and project's site management and T&D, maintenance schedules are determined and regularly updated for several months ahead. The maintenance schedules includes the type of work to be performed on hydroelectric facilities, which includes maintenance and other works on transmission system, generating units, intake structures, trash racks, spill gates, reservoir structures, etc. The Power Facility Maintenance System (PFMS) is used to forecast the daily maintenance schedule for each facility on an hourly basis. The maintenance schedule lists, among other things, type of work to be performed, the specific facility affected, and the start and end dates. It is issued early in the morning every day, and thus does not include any unscheduled changes that could occur within the day. For this reason, and for short and real-time operations planning, extensive communications (and negotiations that involves the Shift Engineer, project's planning engineers, site management and PowerEx) take place to determine the current status of the facilities, and whether some of the restrictions could be lifted, or expedited, particularly during hot market conditions. Results from these communications determine the actual and future maintenance schedules. Using these results, the Shift Engineer determines individual plant and system generating capacities. To aid the Shift Engineer to perform this important function, several software systems are used, one of which is called the Outage Request Form (ORF). ORF provides the Shift Engineer with the ability to gather, update, and archive the latest information on hourly maintenance schedules affecting individual plants, and unit capacities for several days ahead. ORF has been designed and implemented under the direct supervision of the Shift Engineers, with some technical aid from the team involved in development of STOM.

d. Market Conditions

Market conditions, in the form of forecast prices and market demand, are relayed from PowerEx to the planning and system operations engineers. For real-time operations, the market information consists of average demand for electricity, average spot prices, and available tie line capacities to the U.S. and the Alberta markets. The long term information on market conditions consists of opportunities for long term contracts and their prices. It should be noted that much research work still needs to be done on the marketing side of the business at PowerEx. In particular, research work is needed to forecast market prices and demand in the long as well as in the short term.

e. Other Data

In addition to the above data on inflows, load forecasts, unit outages, and market conditions, data on economic parameters, fuel prices and availability, system and individual component constraints, dam safety, environmental constraints, and other physical and operational data are taken into account in the planning process.

iii. Planning Levels

At each of the various planning levels, the engineers responsible for operational planning utilize simulation and optimization models to aid them in this complex task. The models are used to:

- support operating strategy; and
- aid the system operator in making informed decisions on the quantities and prices of electricity transactions, and on the amount of thermal generation required to meet firm domestic load and firm trade transactions, and on other discretionary opportunities.

Results from the simulation and optimization models determine the operating schedules, and dispatch guidelines are issued to the real-time system control center. The following is a brief description of the various operational planning levels currently employed by B.C. Hydro (BC Hydro, 1993; personal communications). Figure 3.11 illustrates the current thinking at BC Hydro (as understood by the author) of the existing and planned operational models and the information processes that integrate the models. The Figure does not include system expansion planning, and it only considers operations planning models. It shows the major information flows between models within the Power Supply Business Units, and between other business units in B.C. Hydro.

a. Long-range System Planning Studies (5–30 years).

Long-range system planning studies are concerned with developing plans for future system expansion. In these studies, two reliability criterion are considered: energy reliability must be greater than 99.2%; and peak reliability dictates that expectations of having insufficient generating resources available to meet the forecasted daily peak load should be one day in ten years, or less. Once these two criterion are satisfied, the time schedule of new resources can be altered to reduce the expected costs of serving the long-range domestic demand. The plan evaluates alternative resource acquisitions that minimize social costs, meet B.C. Hydro's objectives, and meet the economic development objectives of the Province. It incorporates information on available energy capabilities (including demand-side management), construction costs and technologies, operation and fuel supply costs, and environmental and socio-economic impacts. For more information on the long-term planning studies see the "1994 Electricity Plan" (BC Hydro, 1994).

b. Long-term Operations Planning Studies (1-6 years in monthly time-step).

Long-term operations planning studies focus on providing guidance for marketing decisions and for policies on operation of the hydroelectric system. Over the past decade, operations planning at B.C. Hydro has undergone a shift in thinking on how the system should be managed. The traditional approach followed what is known in the industry as critical period energy studies, which focused on energy quantities. Electricity price was considered secondary input to the planning process. The four-year critical period energy studies provide a test of current system conditions based on the lowest sequence of stream flows that actually occurred in the historical record. When the studies show that reliability of energy supplies is not adequate, non firm exports are curtailed, and purchases and thermal generation are maximized to maintain a reliable supply of energy to customers (for more details, see Chapter 5 and 6 in Christensen et al., 1988).

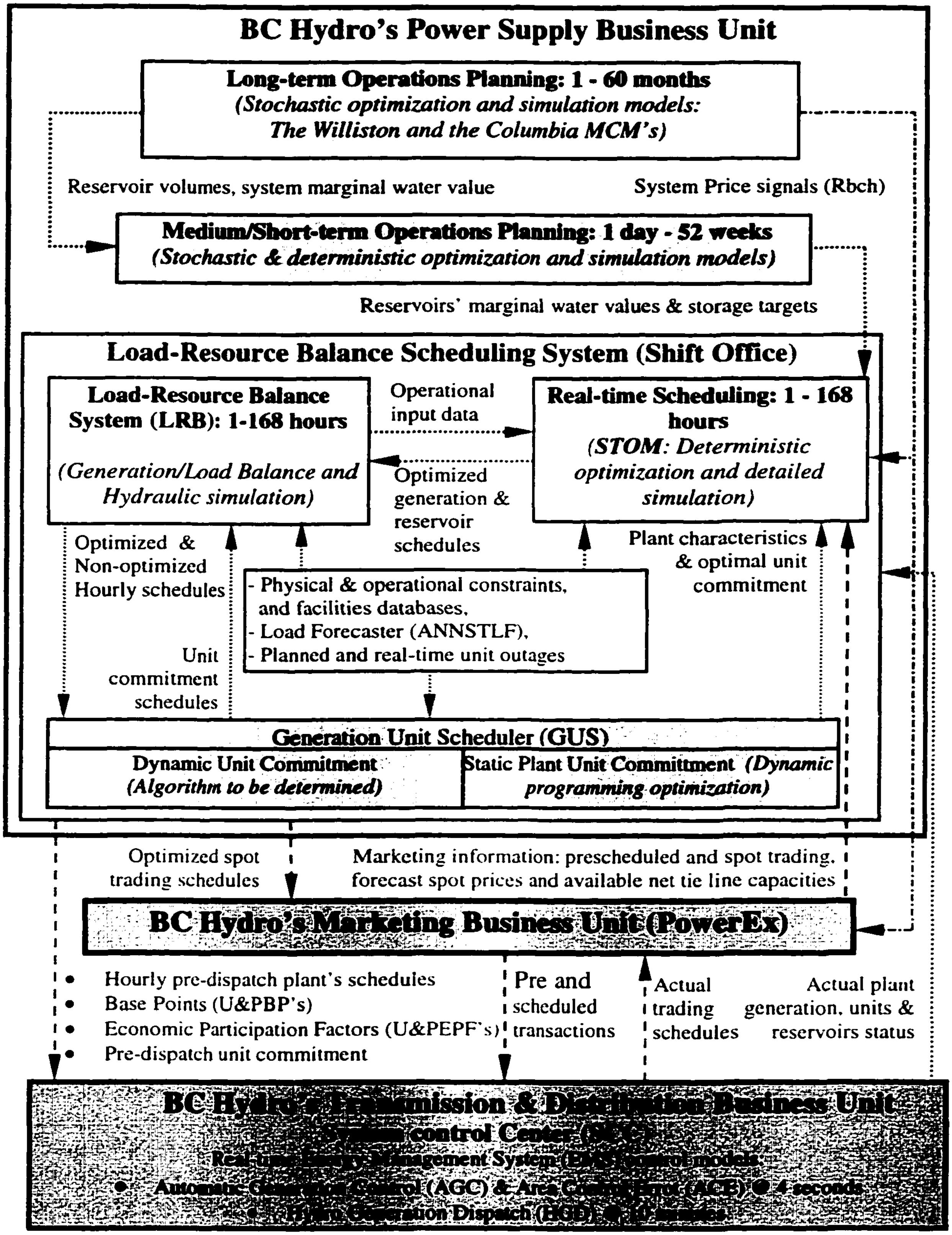


Figure 3.11. Scheduling Problem Modeling Decomposition Hierarchy.

Since D. Druce developed the Marginal Cost Model in 1986 and B.C. Hydro's started to use it, there has been a shift in thinking on the methods used for operations planning. The focus now a day is on the use of price signals to coordinate system operations. The Marginal Cost model is a stochastic dynamic programming optimization and simulation algorithm, developed in-house at BC Hydro. The model calculates the present value of water stored in the Williston Lake with the assumption that the reservoir is operated to balance system load and resources (Druce, 1989; Druce, 1990; Druce, 1994; Druce, 1998). The model incorporates information on inflows, load, and marketing. The state variables of the model are the storage level of the Williston Lake, the weather year, the water conditions in the U.S. Pacific Northwest (PNW) and export price conditions in the PNW. The decision variable is the monthly water release volume. Based on monthly weather patterns, monthly inflow volumes to the Williston are generated. A Markov model forecasts water conditions in the PNW and export price states with state transition matrices based on analyses of historical data. The Marginal Cost Model calculates the expected value of water stored in the Williston Lake for each storage level and month over the planning horizonOF 4-6 years and the reservoir marginal cost claculated from this water value function is used as a proxy for the long-term System Marginal Cost. The model also generates a probabilistic forecast of R_{bch} and of Williston Lake levels, spills conditions, discretionary sales (see d. below) and purchases and net revenue from electricity trade. The marginal cost is considered, by the operations planners, to be directly related to the ability to serve and the value of future export markets and is inversely related to the probability of spill at the Williston Lake. The model provides decision support for interruptible sales, import and export transactions. Operations engineers also use the marginal cost of water, along with current market prices, to determine the cost of unit outages and plant restrictions in the B.C. Hydro system. Other similar optimization and simulation models are under preparation for the Columbia River system and other reservoirs (personal communication from Mr. K. Ketchum and the planning engineers). The Columbia model will incorporate the complex Columbia Treaty and non-treaty storage conditions and is planned to be run in an iterative procedure with the Marginal Cost model to determine the optimal operation and marginal cost of the Columbia system. Until other optimization models are developed for river systems other than the Peace River, the current recommended practice is to estimate the marginal cost of water in other river systems. This is done by first estimating the probability of spill for other reservoirs using simulation models. Once the probability of spill at a reservoir is determined, the marginal cost for that reservoir is calculated by pro-rating the marginal cost of Williston Lake by the ratio of the probability of spill at the reservoir in question and Williston. Judgment is used to account for special reservoir constraints, such as the Non-Treaty Storage activities. The operations planning and system coordination engineers reflect differences in marginal cost between reservoirs in what is called the daily "Generation Schedule Preference Order" (see d. below for details).

c. Medium/Short-Term Operations Planning Studies (next day- 12 months)

The medium/short-term operations studies focus on more detailed system analysis to determine hydraulic and generation schedules for reservoirs, generating facilities and interchanges for the next day, weeks and months for all generating facilities. Detailed information such as short and medium-term inflow forecasts, maintenance schedules, and electricity demand are considered in order to provide operational schedules and guidelines for real-time system operators. The guidelines are issued daily in the form of "Generation

Schedule Preference Order" for all facilities. The Generation Schedule is produced by planning and system coordination engineers, and is issued to real-time generation system operators (the Shift Engineer). It includes instructions and guidelines on how the generating system should be operated and a stacking order for running plants (e.g., run the resource with the lowest cost first). It also includes spill and minimum outflow requirements, as well as unit outages and facility specific schedules and constraints. Experimentation with commercially based optimization models, such as the Small Reservoir Simulation Model (SRS) (Smith, 1997), as well as in-house development are underway to determine the usefulness of such models for short-term operations studies of this nature. In addition, discussions on the utility of using intelligent expert systems (Shawwash et al., 1998) to standardize and automate some of the short-term planning functions (e.g., spills, facility outage schedules and constraints) are underway. To aid decision-making, forecast system conditions, forecast inflows as well as real-time information are relayed to the planning engineers (see d. below for description of the SCADA and PI systems and a brief description on the Commercial Resource Optimization Project in Section 3.1.3).

d. Real-time Operations Planning Studies (1 hour – 1 week in hourly time-step).

The "Shift Engineer" performs real-time generation operations planning with the focus on day-by-day and hour-by-hour operation of the system. It is the most detailed of all planning study functions, as it deals with real-time aspects of translating the long and medium-term policies, strategies and guidelines, developed by other higher level studies, into actual implementation. The Shift Engineer follows closely the guidelines set out in the Generation Schedule Preference Order and utilizes information on discretionary opportunities. Discretionary opportunities arise if storage as well as generation is not tightly constrained -whether there is operational flexibility and surplus in the system, and when water can be stored for later use. With discretionary opportunities and "hot" market conditions, real-time operations engineers can "push the system to its limits" (both the maximum and minimum limits).

To aid the planning process and the shift engineers in making decisions, system behavior is monitored through an extensive network of measuring devices installed throughout the B.C. Hydro electric system, to record and relay real-time information on unit generation, system load, reservoir levels and other operational aspects. This monitoring system is very complex, and utilizes, as its backbone, what is known in the industry as a Supervisory Control and Data Acquisition system (SCADA). The computerized data in this system is shared between the Power Supply and Transmission and Distribution business units on a real-time basis. It is relayed to the operators in the Shift Office and Transmission and Distribution control center to manage the system behavior remotely through a set of control devices distributed throughout the generation, transmission and distribution network. The Shift Engineer collects the computerized SCADA data and displays it on several computer screens using a commercially available, advanced monitoring system called the Plant Information system (PI) (OSI, 1996). The PI system was originally designed and configured to monitor oil well fields and petroleum refinery production units and it graphically display and update the instantaneous status of the production facilities.

The Shift Office coordinates its activity very closely with the "System Control Center" (within the Transmission and Distribution (T&D) business unit) and with PowerEx (the power marketing subsidiary of B.C. Hydro). The T&D control centre loads individual generating units using the Energy Management System (EMS) and other feedback control devices so that system loads and resources are balanced instantaneously. The transmission and distribution system is operated by the control center to meet two main objectives: security and reliability of the service. Economic criteria are secondary, and it enters the feedback-control function in the form of what is called in the industry as the Unit's and Plant's Economic Participation Factors and Base Points control functions (for more details, see Chapter 3 of Wood et al., 1996). The system control centre coordinate its activities with other members of the Western Systems Coordinating Council (WSCC), a group of electric utilities serving Western Canada and the Western United States, to ensure that disturbances in BC Hydro's system will not cause disturbances to other neighboring interconnected utilities. Coordination between PowerEx and the Shift Engineer Office is intended to set the short-term and real-time potential trading schedules. It should also be noted that PowerEx coordinates its trading activities very closely with the T&D control center to arrange for the delivery of its trading contracts.

The Shift Office is the nerve centre for all generation activities in B.C. Hydro. It is responsible for directing the short-term operation of the hydroelectric and thermal generating facilities. The office works very closely with PowerEx's real-time energy traders who sell and purchase electricity in the spot and forward power markets in the US and Alberta. The office also prepares the daily and hourly generation schedules and coordinates its activities with long-term operations planning activities carried out by project planning and system coordination engineers. Using the hourly Load Resource Balance spreadsheet (LRB) that is linked to the Forebay Forecaster (FBFC) spreadsheet, the office updates and sends the hourly generation schedules to the System Control Centre for real-time dispatch and control of the generating facilities.

To perform the duties in a timely manner, the function of the Shift Office has been divided into two activities: the first is concerned with planning for the next few days, and the second is concerned with real-time operations for the next few hours. The Shift Office manager and seven shift engineers who work in rotating 12-hour day and night shifts and between the two jobs, currently carry out the two functions.

The Next Day Planner (NDP) performs planning for the next few days, while the Shift Engineer on day and night shift duty performs real-time operations. The NDP works regular office hours at B.C. Hydro's Edmonds office complex in Burnaby, alongside the project's planning and system coordination engineers. The NDP coordinates very closely with the projects' planning engineers to determine the energy budget and capacity available for dispatch from each plant for the next few days, and determines the potential electricity forward trade schedules. Long-term contracts however are determined by direct coordination between Power Supply system planners and PowerEx using outputs from long and medium term marginal cost optimization models as described in Sections a. and b. above. Several schedules are prepared and sent by the NDP to the Shift Engineer, and to PowerEx. These schedules reflect the preference order for running the generating system and are updated frequently. The NDP ensures that the prepared schedules are feasible operational plans.

The Shift Engineers work 12 hour day and night rotating shifts in the Shift Office, which is located in PowerEx's offices in Downtown Vancouver, alongside PowerEx's real-time trading floor, which is also manned 24 hours. The Shift Engineer is responsible for monitoring real-time behavior of the generating facilities and for determining their real-time dispatch. He also determines the potential spot trading opportunities for the next hour(s), and sends instructions to the System Control Centre for instantaneous control of the generating facilities. These instructions (in the form of what is known as Plant and Unit Base Points and Economic Participation Factors) direct the System Control Center on actual dispatch of the generating plants and units.

To perform the above functions effectively, the Shift Office has been equipped with computers, numerous software programs, and display facilities that help the Shift Engineer to monitor the instantaneous behavior of the generating system. An extensive effort was undertaken since the creation of the shift office in 1996 to automate most of the functions that the Shift Engineer performs. These include automation of data acquisition and transfer routines, system planning and operation instructions, calculation procedures, and display facilities. It should be noted that the Shift Office manager and the Shift Engineers were directly involved in the design, computer programming and implementation of almost all of the computer systems and monitoring facilities they currently use in their daily operations.

To be able to perform their duties efficiently, the Shift Engineer needs to integrate several inputs in order for effective decisions to be made:

- Domestic load forecast;
- Market forecasts (prices and demand);
- Water supply forecasts;
- Current and future conditions of the hydroelectric system;
- Capabilities of the generating and transmission systems;
- Operating costs and potential revenues;
- Operational risks such as flooding, violation of water license limits, regulatory and environmental requirements and constraints;
- Reliability and security of the overall electric system.

Prior to the introduction of optimization techniques (primarily STOM) at the Shift Office, intensive use of simulation was utilized to determine generation schedules and reservoir operations. The simulations were carried out using two Excel spreadsheet models, which were designed and developed in-house by the Shift Office manager, the Shift Engineers and a team of supporting computer programmers, the Load-Resource Balance (LRB) system for balancing plant generation schedules with system load, import and exports; and the 96-Hour Forebay Forecaster (FBFC) for balancing hydraulic reservoir operations. Both models are linked and they contain routines for data acquisition and communication with other systems (PowerEx and the T&D System Control Center). The LRB is also equipped with extensive facilities to launch other software systems and to read results into the LRB and FBFC. Extensive use of these simulation models and the results obtained give the Shift Engineer an understanding of the hydraulic response to generation schedules in each river system. Using their experience and judgment, aided by the LRB and FBFC models, and rules-of-thumb to load generating plants, reservoir operations are determined by the following main steps:

- The planned and real-time generating unit outages are determined. Based on these outages the available system generation capacity is calculated. To calculate the generating capacity a stand-alone software system was developed with the help of the team of researchers and programmers who participated in developing STOM.
- The small generating plants are scheduled as per instructions in the Generation Schedule Preference Order (see section c above for details), the hydraulic response to these schedules is then determined, and a balancing act is performed to balance the

small reservoirs' water levels in accordance with predetermined spill instructions and reservoir level limits. The main variables used to hydraulically balance reservoir levels are the plant's generation, and sometimes spills, for each hour;

- Prescheduled imports and exports from PowerEx are read by and inserted into the LRB;
- The neural network model ANNSTLF calculates the forecast system load, and a quality and sanity check is then manually performed to correct for any deviation from observed trends of the actual system load. A simple spreadsheet model that traces the 5-minute moving-average of actual load is used to determine the most likely next hour system load.
- Preliminary potential spot trading schedules are calculated in close consultation with PowerEx real-time traders.
- The residual generation required for balancing load and imports/exports with generating resources available is then determined. Usually, the largest plants in the system (Mica, Revelstoke, G.M. Shrum, and Peace Canyon) are used to perform this balancing in accordance with the Generation Schedule Preference Order;
- The regulating and operating reserve margins are then determined to ensure that there is enough available generation resources to meet fluctuations in load within the hour and to meet the WSCC's reliability criteria;
- The final potential spot trading schedules are determined in close consultation with PowerEx's real-time traders. Consultation with PowerEx includes verbal communication of the current prices and demand in the Alberta and U.S. markets;
- The balanced schedule is then communicated to the System Control Centre. A generation schedule covering a time-frame of 24 hours is communicated and updated every hour for security purposes;
- Once the hour has ended, the previous hour's actual load, reservoir levels, plant generation, etc are updated;
- The process is then repeated for the next hour.

Planning system operations with these iterative techniques became more difficult as the market for electricity expanded and the problem became that of trading off the available resources in storage against the dynamic spot market for energy in the U.S. and in Alberta. Where previous options facing the engineer were essentially to run the generating facilities as reliably and as efficiently as possible and either to store or sell system energy, he now had the additional option of either importing or exporting the discretionary resources available. Given that option, the question of when discretionary resources should be sold or purchased and at what price, needed to be included in the planning process. In addition, the traditional operation norm was to maximize the efficiency of individual generating plants by using plant efficiency curves. No concern was given to maximize the efficiency of the system as a whole while also maximizing the revenues achievable. These questions were not easily answered because the incremental value of the surplus energy depends upon the volume sold from each reservoir, and system efficiency depends on how the system, rather the plants, are dynamically operated, let alone meeting the system constraints. Developing the correct answers to the above concerns had high economic value due to the rapid growth in the trading and pricing of electricity as a commodity. Every incremental unit of energy, and capacity, that could either be generated or stored to take advantage of market conditions was valuable. In addition, it was becoming apparent that the Shift Engineer could no longer take time to perform routine calculations in a time-consuming iterative manner to completely analyze the options available, while also operating the system reliably, efficiently, and in-time to meet the next hour's schedule. Computerized analytical capabilities thus became necessary to enable the Shift Engineer to make timely and informed decisions.

3.2.5 Summary of Key Features of the BC Hydro Generating System

Several key features of their hydroelectric generating facilities make the B.C. Hydro system distinct from other systems in the world. First, the large storage capability of Williston Lake on the Peace River and the Kinbasket, Duncan, Arrow reservoirs on the Columbia River ensure a sufficient supply of water for hydroelectric production throughout the year. Second, the Columbia River system Treaty and Non-Treaty storage, and the ice formation on the Peace River during the winter months impose restrictions on the operation of these systems. These restrictions "propagate" to influence the operation of almost all other generating facilities in the system. Third, the physical distribution of generating facilities across the Province provides for the very important reliability and security operational criteria for the transmission network. Fourth, with about 75 billion cubic meter of water storage capability, and the large provincial demand the generating system is capable of absorbing significant energy imports during low market price periods. The same energy can later be exported during high market price periods, sometimes to the same market it was purchased from. The only limitations are the tie line capacities to other markets, and the environmental, physical, and operational limits on minimum flow and generation requirements. Fifth, the generating system operated by B.C. Hydro is mostly hydroelectric. Hydroelectric generating facilities enjoy an important advantage over thermal generating facilities in that they can be shut down and re-started in very short times (few minutes). Thermal-generating facilities require lengthy start-up and shut-down procedures that can take few hours, or even days (in the case of nuclear generating units). Thus the costs of shutting down and starting up hydroelectric generating units are negligible in comparison with those for thermal and nuclear units. Finally, B.C. Hydro is one of the few utilities in the region (and in the world for that matter) enjoying large relatively low cost domestic hydropower resources, which gives it a competitive advantage over neighboring jurisdictions.

3.2.6 Electricity Trade Operations

i. Background

B.C. Hydro has been trading electricity on a short-term basis for the past 20 years. Since its creation in 1988, PowerEx became the subsidiary of BC Hydro that is actively involved in electricity trade operations outside the Province of British Columbia. PowerEx is actively expanding its market share in the western U.S., in Alberta and more recently (1997) in Mexico. It operates as far east in the U.S. as Wisconsin, and as far south as Mexico to sell B.C. Hydro's energy surplus and other energy sources from the U.S. and Alberta. Energy surplus to the domestic needs of British Columbia is identified by the Power Supply Business Unit and is made available to PowerEx for trading operations. Recently the U.S. Department of Energy granted PowerEx the permit to export electricity from the U.S. into Mexico. In addition, in September 1997, PowerEx secured a Power Marketing Authorization from the U.S. (FERC), which has increased electricity trade opportunities for PowerEx, as it allows for the delivery of wholesale power sales and purchases directly in the U.S., rather than doing business at the B.C./U.S. border. PowerEx also is actively involved in recruiting large and small industrial customers to its pool of market share in the U.S. It should also be noted that PowerEx is not the sole exporter of electricity out of British Columbia. In 1991. the Independent Power Producers in British Columbia were allowed to negotiate directly with potential purchasers of electricity generated in B.C.

Commercial exports of electricity follows the new policy of the provincial government issued in July 1993. The key features of this policy are (BCUC, 1995):

- Utilities and the Independent Power Producers can participate in the export market. B.C. Hydro can only export through PowerEx;
- Utilities in British Columbia will have the opportunity to bid on the power to be exported before it can be exported;
- Security of supply for domestic customers should be assured before utilities can participate in export markets;
- exports will not be subsidized by domestic consumers; and
- all export projects will be subject to British Columbia's environmental standards.

Due to high stream flows and good market conditions, electricity sold in fiscal 1998 totaled 56,500 gigawatt-hours, of which 23.3% represented out-of-province electricity trade. Real time electricity trade has increased about 20 fold since B.C. Hydro started their real time marketing operations in September 1996. The revenues from total electricity trade have been on the rise and accounted for about 13.5% of total revenues in 1998, up from an average of 5.5% for the previous five years (B.C. Hydro, 1998). The major factors that contributed to this increase are more active real time marketing due to the move of the electric industry in North America towards deregulation; integrating marketing with operations; and designation of shift staff for real time power supply operations and electricity trade. Figure 3.12 shows the growth in electricity trade revenues as compared to revenues from sales to domestic customers, and it also shows the growth in electricity generation for trade and for domestic purposes.

ii. Types of Trade Transactions in Electricity Markets

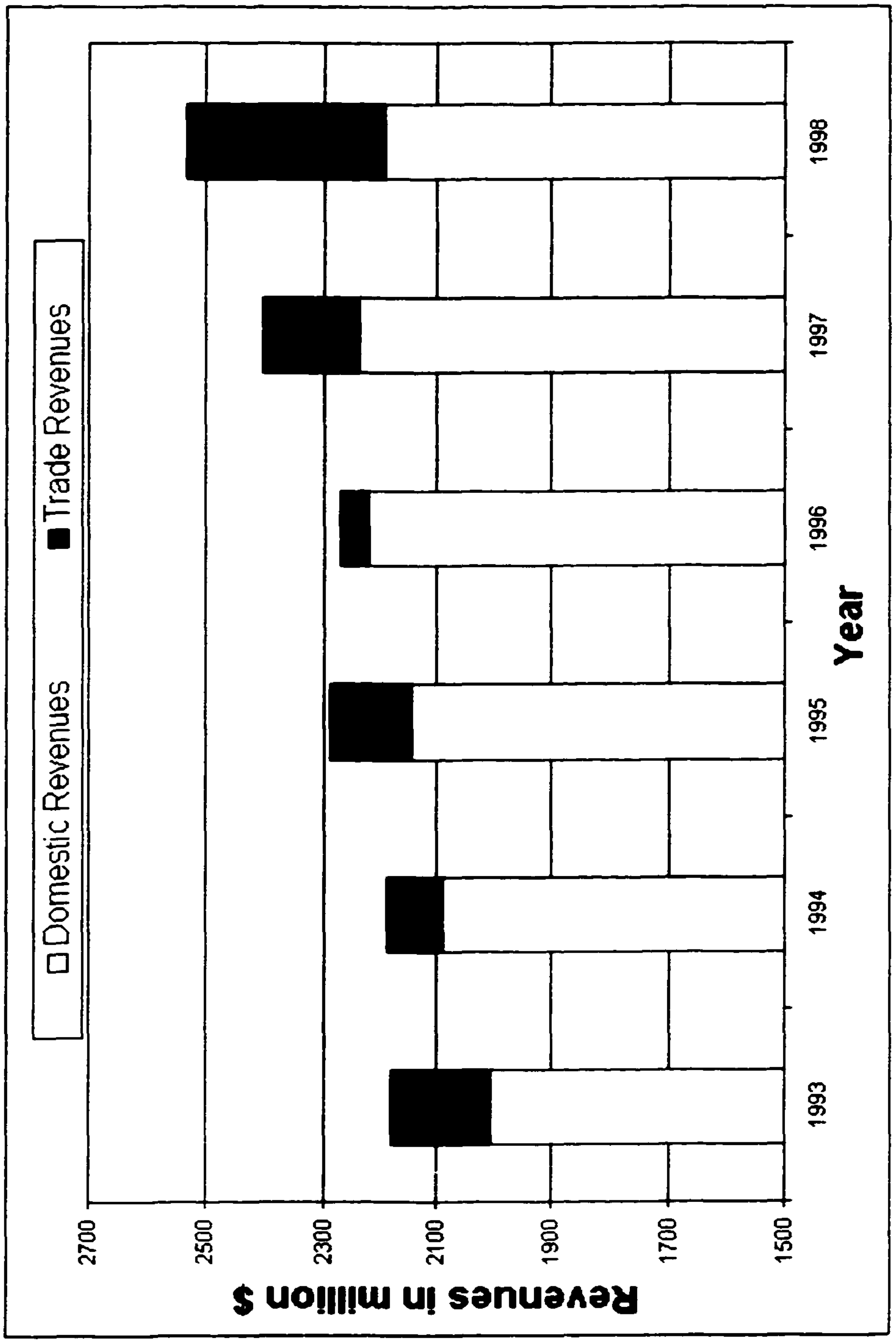
Several types of trade transactions can take place in the emerging electricity markets. PowerEx primarily trades in the Alberta Power Pool and in the U.S. in the wholesale marketplace. At present, regulations prevent PowerEx from trading on the futures market. However, it is anticipated that this regulation will be changed in the near future.

Generally, there are three main types of electricity transactions in the wholesale marketplace: Bilateral Contracts, Contracts-for-Differences, and Poolco bids. Both long and short-term bilateral commodity contracts are written between specific electricity producers, and are based on some form of competitive process. As prices in these contracts are fixed, this is considered a complete hedge against uncertainty. The Contract-for-Differences is similar to bilateral contracts with the exception that payments between parties are determined by the differences between the contract price and the spot price, and they are thus considered as "hedges" against the spot price. The Wholesale Poolco bid process requires that participating players submit their bids for specific trading period. This can take place a week, a day or even an hour ahead. The function of the Poolco operator is to arrange the bids received in order of lowest to highest bid to build the generation supply curve for the period in question. Based on the generation supply curve, Poolco dispatches the required generation facilities to meet the projected system demand, with consideration given to transmission and other system constraints. The price of the last and most expensive generator dispatched determines the pool price, and this is the spot price. Transactions are settled each hour, and all generators receive the spot price for their production in that hour, and are paid by the local distribution company. Under this system, producers and utilities can enter into Contracts-for-Differences.

In April 1996, an active market for electricity futures developed on the New York Mercantile Exchange (NYMEX). In NYMEX, electricity is now traded as a commodity. The electricity contract is structured for 2 MW of capacity, for 16 hours-day, on each business day of the week to cover delivery of 736 megawatt-hour of firm energy per contract in a month. NYMEX provides futures market for electricity contracts written for delivery at two locations: COB and PV. COB refers to the California Oregon Border, while PV, refers to Palo Verde generation complex in Arizona. Although most of the contracts are not currently intended for actual delivery, a few are, which means that the futures contract prices and prices in cash markets converge at the delivery date. The value of these contracts is quoted daily in the Wall Street Journal, along with quotations from other commodity markets for two spot markets: COB and PV. The COB price index has varied considerably with daily and monthly price variations of 25%, and 200% respectively (Power Engineering, 1996). The futures contract prices at COB and PV are based on prices in these spot markets at different points in the future. The Alberta Power Pool prices are shown in Figure 3.13, while NYMEX futures market prices are shown in Figure 3.14 for COB. Figure 3.15 illustrates what is known in the industry as the Mid-Columbia (Mid-C) prices, which is indicative of electricity prices in the Pacific Northwest. It can be noted from the Figures that electricity prices are volatile as discussed below.

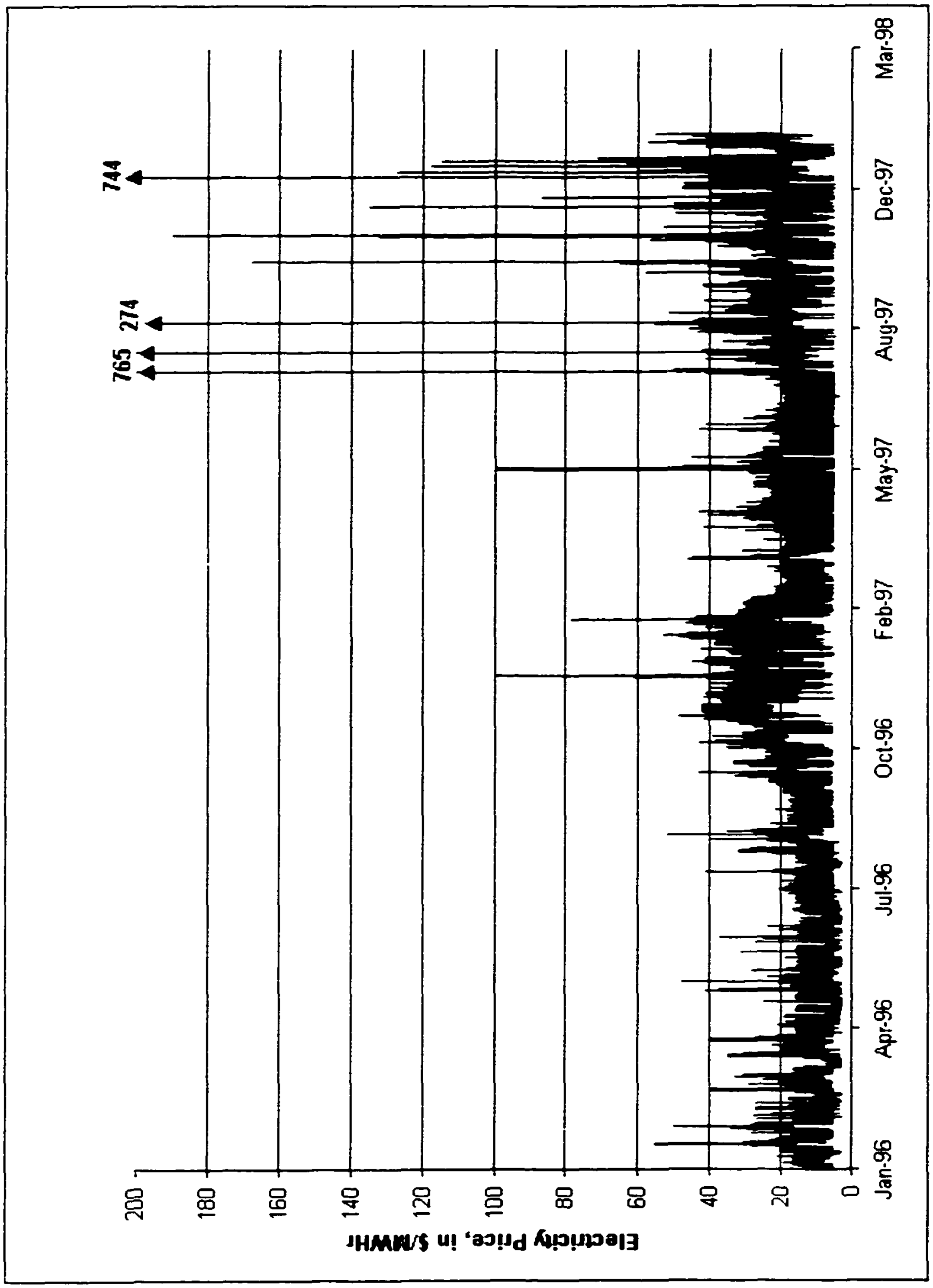
iii. Nature of Electricity Prices

It is widely recognized that electricity prices are much more volatile than other commodities traded in NYMEX (and money markets for that matter) for several reasons (Douglas, 1997). First, electricity is not readily storable (aside from hydroelectric reservoirs), and there are no large-scale reserves to smooth out the peaks and valleys of hourly demand. Second, response to electricity demand should be instantaneous, otherwise disturbances and blackouts could occur. Thus generation in response to continuously changing demand leads to wide intra-day price swings. Third, low cost power in one region may not be available to meet demand in another region if a transmission network does not interconnect the regions, or the transmission network is of limited capacity. Fourth, weather conditions, affecting supply and demand for electricity in one region could considerably vary from season to season, and within the same season. Fifth, the electricity markets are recent phenomena, and prices for electricity, both for immediate sale and for sale in the future, are hard to establish. Sixth, the current players in the market are predominantly large-scale monopolies, who can "game" in the market to raise electricity prices significantly. For a full account of why energy markets are different from other market structures, see Pilipovic (Pilipovic, 1998).



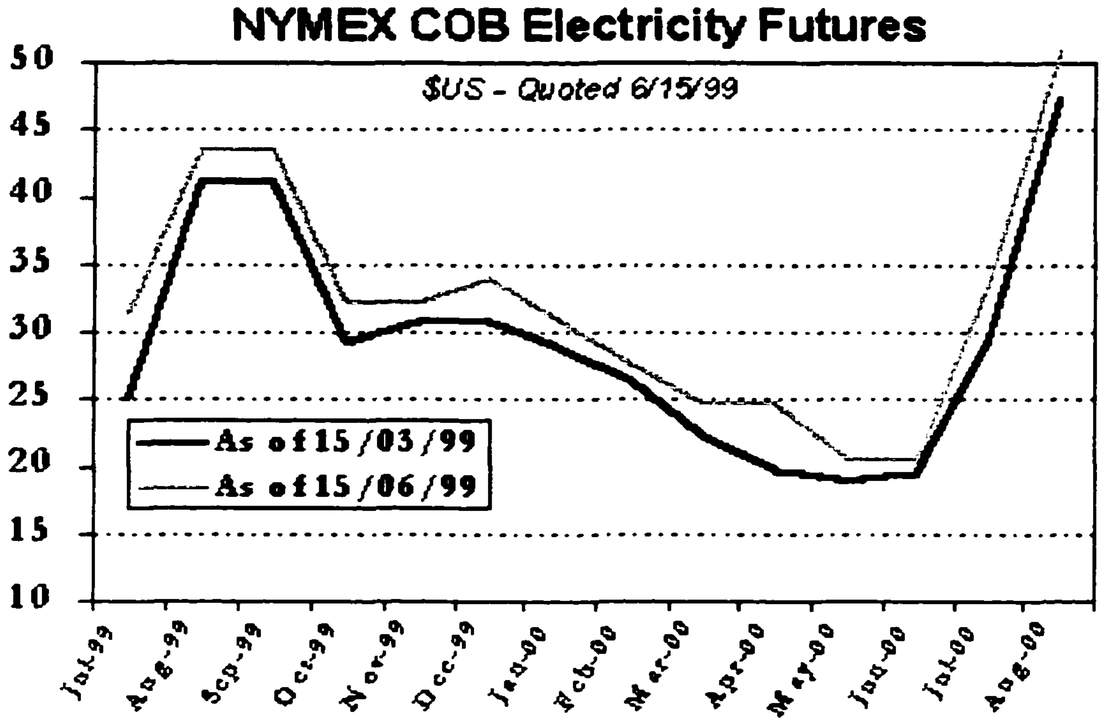
Source of data: BC Hydro, 1998a.

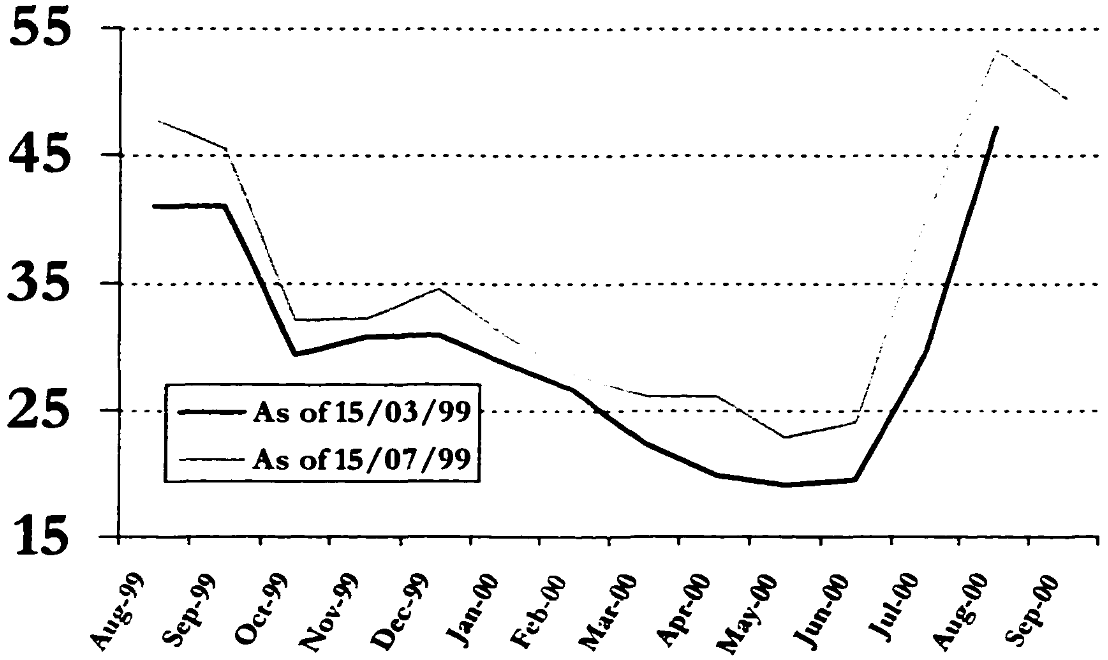
Figure 3.12. Growth in Electricity Trade Revenues



Source of data: Alberta Power Pool WEB Page.

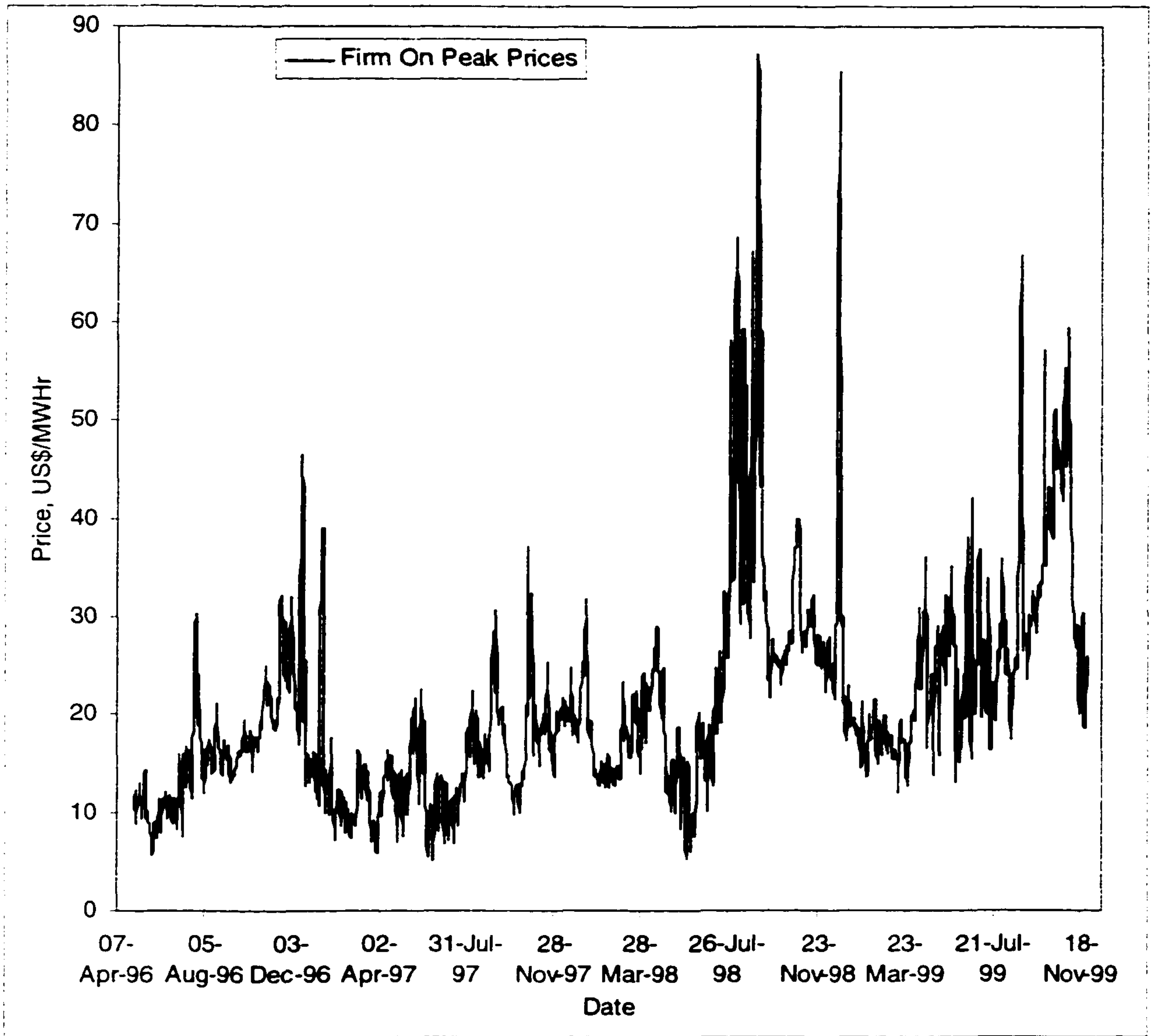
Figure 3.13. Alberta Pool Spot Prices





Source: Resource Management, BC Hydro, 1999.

Figure 3.14. NYMEX/COB Electricity Futures prices



Source of Information: Resource Management, BC Hydro, 1999.

Figure 3.15. Mid-Columbia Electricity Prices.

iv. Major Benefits of Electricity Trade

It is widely held that electricity trade improves the security and efficiency of electric systems. It also can provide significant additional revenues in predominantly hydroelectric systems during wet years, since surplus water can be stored in reservoirs. Electricity trade is enhanced by the fact that demand characteristics, type of generation, and climate in different regions vary. For example, during the summer months high demands for electricity in Southern California arise from the use of air conditioners, while demand in B.C. is low, and reservoir inflow is high, which means that a "hot" spot market can develop in the months of July and August in California. Another example is the high demand in winter months in Alberta, which arises from the use of electricity for heating purposes. This coincides with low demand in California and to some degree low demand in B.C. Electricity trade is also made possible because the B.C. Hydro transmission network is interconnected with transmission networks in Alberta, West Kootenay Power in southeastern B.C., the Alcan system in the North Coast, and the interconnected system in the western United States. Currently, the tie line to Alberta provides interchange capacity of up to 1100 MW, while the ties to the U.S. provide interchange capacity of approximately 3250 MW.

Several conditions make electricity trade a viable option for utilities to consider. First, in wet years, surplus water stored in reservoirs can be used to generate and trade electricity in the market. Since B.C. Hydro possess considerable storage capability, surplus water can be stored and converted at a later date to electric energy. When storage capability is not sufficient to store the total volume of water inflows, then water is spilled, and the opportunity is lost. Second, in dry years shortages of generation due to low water levels can be compensated for by purchases of surplus energy from other utilities. Third, in emergency situations, electricity can be purchased from other utilities to provide backup power. For instance, if a number of generating units were suddenly put out of service, or when a major transmission line is de-energized for a fault or for other reasons, other neighboring utilities can be called upon to provide support to compensate for the loss. The procedures to reinstate these outages due to system disturbances are usually automated to prevent blackouts (or brownouts). Fourth, electricity trade can also be used to "time-shift" the generation of other systems that do not have reservoir storage and peaking capability –a key feature of hydroelectric generating facilities. Fifth, significant revenues can be earned through simultaneous sales to and purchases from other electric utilities (arbitrage).

During the past few years, B.C. Hydro has realized significant benefits from electricity trade through coordination of its system operations with other utilities in Alberta and the U.S. It is widely held that these coordination activities optimize the interconnected system resources, increase its security and reliability, and that it provides significant financial benefits to British Columbia. Current coordination agreements exist between B.C. Hydro and West Kootenay Power, Cominco, Alcan, TransAlta Utilties in Alberta, and the Bonneville Power Administration. The main objective of such coordination agreements is to share the resulting cost savings. Three examples illustrate the benefits of such coordination agreements. First, due to the flexibility of hydroelectric resources, B.C. Hydro is able to rapidly change its generation levels to follow variations in load with almost no cost incurred. This is in contrast to purely thermal systems, where changes in generation levels can cause considerable increases in fuel costs. The coordination agreement between B.C. Hydro and the TransAlta Utilities exploits the flexibility of the B.C. Hydro system to import energy and store water in reservoirs during off-peak hours at night and generate electricity and export it to Alberta during day peak hours. Second, due to different stream flow and runoff patterns, some neighboring utility, with predominantly hydroelectric system, could experience low stream flow conditions while B.C. Hydro's system inflows are higher. Altruism plays an important role under these conditions, where the water-rich utility could be called upon to support the water-poor neighboring utility. Third, storage agreements plays a major role in storing water surplus to immediate requirements for one utility located downstream in the same river system for more beneficial use at a later time. B.C. Hydro frequently acts as a water-banker to store water in the Columbia River storage facilities for U.S. utilities in the Pacific Northwest during May and June when stream flows are high in the Columbia River system. This stored water is released when it is more valuable to use. It should be noted here that operations of storage and hydroelectric facilities in the Columbia River system in the U.S. are much more constrained than the hydroelectric facilities on the Columbia River system in B.C. This stems from the strict environmental and regulatory constraints imposed in the U.S. These constraints severely limit one of the main features of hydroelectric generating systems –namely, their generating flexibility over other types of generating systems (e.g., nuclear and thermal).

3.3 DECISION-MAKING PROCESSES AND DECISION SUPPORT SYSTEMS

3.3.1 Decision Making Approaches in Organizations

Aside from engineering, decision-making approaches can be found in the fields of information technology, economics, operations research, management science, organizational behavior, and other fields of study. In their review of the state-of-the-art in the fields of operations research and management science, leading scientists in the field have recognized that one of the highest potential research areas still yet to be addressed include decision making in organizations (Simon et al. 1987a, p. 27):

> "Although the decision making processes of organizations have been studied in the field on a limited scale, a great many more such intensive studies will be needed before the full range of techniques used by organizations to make their decisions is understood, and before the strengths and weaknesses of these techniques are grasped."

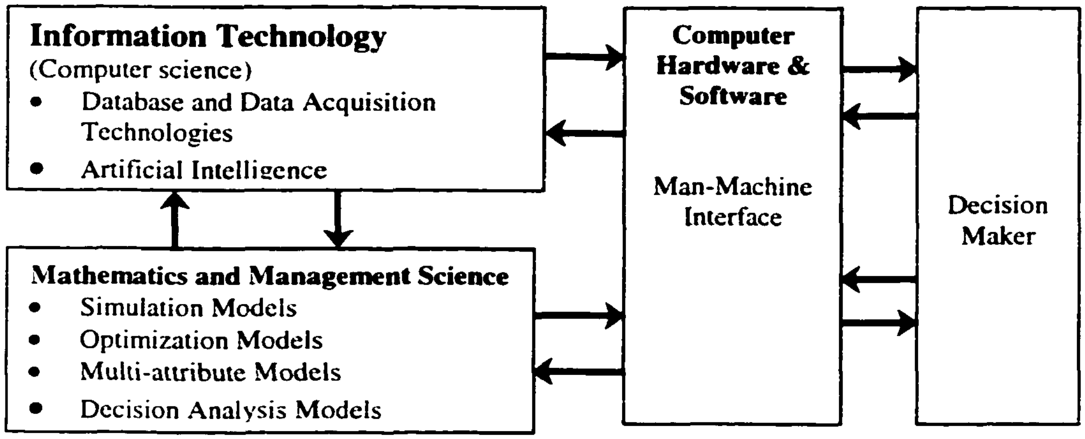
Concern over understanding the decision-making processes in organizations, and understanding the factors that should be considered in arriving at organizational decisions prompted the Nobel Prize Committee on economics to award the Nobel Prize in Economics to Coase in 1992. Coase argued that current methodologies in economics ignore important aspects of decision making in organizations such as transaction costs and the set of rules and regulations that organizations have to deal with in arriving at their operational decisions.

A brief overview of available decision making methods and processes, and decision supports systems is given as background.

3.3.2 Historical- Development of Decision-Making Methods

Although humans have been making decisions since the early days of their existence, decision analytical techniques and decision analysis methodologies are relatively new. For instance, many of the founding fathers of the field of decision analysis and the people responsible for developing the techniques are still alive today. It is well known that mathematicians and philosophers have long tried to develop formal theories and models that attempted to describe human behavior in decision-making situations. By the end of World War II the field of operations research advanced the scientific framework for problem solving and theories on military tactical problem solving emerged. The era also marked an accelerated trend towards automation and mechanization, with the aim at relieving humans of some of the mental and physical tasks they perform in their daily functions. By the 1950's and 1960's, developments in the fields of computer and operations research went hand in hand. What followed was the rapid development of specialized computers and computer applications tailored to solve the growing needs of management in complex industrial organizations. Operations research scientists and other researchers in the field of mathematical modeling have developed and refined algorithms and mathematical theories and attempted to apply them to industrial production processes.

Since the 1980's, the new generation of computer technology (software and hardware) has allowed a convergence of the fields of information processing and



Adapted from Mitra 1987.

Figure 3.16. Interactions between Science, Technology and the Decision-Maker for Solving Decision Problems

mathematical modeling. The aim has been to create computer based tools which could help humans to make better decisions and to control complex processes in a timely fashion. The field of Artificial Intelligence (AI) is making notable advances that cannot be ignored, as Mitra elegantly captured it (Mitra, G. 1987; see also Simon, 1987b):

> "Many of us who come from otherwise traditional OR and management science backgrounds need to take into account a particular aspect of decision support tools which has led to the introduction of newly emerging artificial intelligence (AI) methods in a big way. The case is set out below in its essential form. Decision-making requires careful gathering and evaluation of facts, ascertaining relative merits of chosen alternatives and reasoning about consequences. In its widest sense mathematics is concerned with manipulation of information, problem representation and arriving at conclusions. This is achieved by reasoning about properties and deriving theorems that relate to a particular problem domain. Thus the mathematical inference procedure which can be based on alternative theories of logic is ideally suited to provide abstract representation as it captures the common denominator for a range of otherwise unrelated problems. In the normal course of events such abstractions only amounted to elegance and completeness until computers were really established as a major gadget in our working and private lives. ...
>
> A fundamental focus of AI research is decision-making application. Effective decision-making and supporting the decision-maker are also the major concern of management science and database technology. These taken together have led to the concept of a decision support system (DSS)."

3.3.3 *Structure of Decision Support Systems*

A decision support system should form the link between the decision-maker and the technologies, methodologies and techniques that could be used to make decisions. Such an arrangement can be depicted in the generalized model shown in Figure 3.16. The model could consist of the following components:

- The decision-maker, who is interested in finding a solution for the problem;
- The man-machine interface that provides the means by which the decision-maker could communicate his/her preferences and values, and present the results of the analysis. Understandably, this interface consists of computer software and hardware;
- The technologies capable of providing the information needed to perform the analysis and to make informed decisions; and
- The methods and techniques suited for analyzing and solving the decision problem, and interpreting the results.

Many believe that computers will play an important role in the automation of control processes of the routine type. The above model emphasizes the view that higher level decision-making will, now and in the near future, be made by human decision makers, primarily because they, through the exercise of their mental abilities, possess the only currently available means of integrating and interrelating information for which rational formulations are not yet possible, or are too expensive and cumbersome to build, or are very difficult to sell to end-users. Nevertheless, many routine control functions, which do not require human judgment, will eventually end up programmed as decision-making functions, particularly for real-time control of production facilities (e.g., control of generating units) and for interpreting and executing well defined operational procedures.

3.3.4 *The Need for Decision Support Systems*

A valid question could then be asked as to why a decision support system is needed for planning the operations of hydroelectric facilities? To answer this fundamental question, one only has to consider the following points. First, deregulation of the electric industry all over the world increased the complexity of decision making problems, because the system operator is no longer only concerned with operating the system efficiently to meet the load, but also has to make tradeoffs that maximize the value of resources under their control, while respecting all of the physical and operational constraints. Second, the methods for hydroelectric scheduling have become fairly reliable and are becoming a necessary component of the daily operations of organizations. Third, computer technology (both hard and software) has become advanced and user friendly such that the average operator is becoming accustomed to and willing to use them. Fourth, the time spent on preparing the schedules could more productively be spent on other more important tasks (such as attending to emergency situations). Fifth, both the financial and operational risks are too high for any rational operator to handle unaided. Sixth, the hydroelectric scheduling problem is very complex and its solution requires several sophisticated computer models to be developed and linked in a coherent and conceptually correct approach.

In managing a complex hydroelectric system, a set of policies, objectives, and operational procedures in an organization are usually formulated to direct the system operator in making the day-by-day operational decisions. The operational procedures could typically reflect the policies and objectives of the organization and they could lay out rules and regulations, which in effect outline the way decisions should be made. Ideally, ground rules could be set to eliminate the shortcoming of human judgment under pressure, which is characterized by bounded rationality (Simon, 1979). Rational behavior, in this sense, is typified by a decision maker who has "well-organized and stable system of preferences and a skill in computation that enables him to calculate, for the alternative courses of action that are available to him, which of these will permit him to reach the highest attainable point on his preference scale" (Simon, 1955). Although Simon discards the idea that the behavior of organizations in choice situations fall far short of the idea of "maximizing" advocated in economic theory (see Baumol, 1977 Chapter 15), he clearly emphasizes the need to develop decision support systems intended to aid organizations to reflect their system of preferences, and to considerably speed-up computations to assess the set of alternative actions which permit them to reach the highest point on their preference scale.

A decision support system can then be defined as a computer based application system that helps the problem "owners" to make decisions. The methods and techniques for constructing decision support systems are not the central theme of this thesis, as the topic is extensive and the subject of extensive research as discussed by Sprague et al. (1982), Bonczek et al. (1981), and Turban (1990; 1998). The central theme of developing decision support systems, however, is that people are not good calculators of the dynamic behavior of complicated systems, and that the number of variables that people can in fact properly relate to one another is very limited. This is true since the intuitive judgment of even a skilled operator is quite unreliable in anticipating the dynamic behavior of a simple system of perhaps five or six variables (Forrester 1992). Such limits in anticipating system behavior are true even when the complete structure and all parameters of a system are fully known. This notion of limitations on processing and computing abilities of human decision makers focuses attention on the need to develop a set of decision support tools to aid the decision maker in translating the sets of policies, objectives, procedures and ground rules laid out by the organization into operational decisions.

Decision support tools can be in the form of mental models or mathematical models. Mental models can be in the form of cause and effect, where the observed cause can trigger an automatic, previously learned, response –as in the case of experienced hydroelectric system operator in flood situations. Mathematical models, on the other hand, rely on a set of predefined mathematical relationships that, depending on the level of detail desired, portray the structure and the way the system should be operated given the policies, objectives, and operational procedures.

It is easy to see why mental models fail in meeting the sets of policies, objectives, and operational procedures. For instance, the long-term and short-term scheduling problem of a large-scale hydroelectric system offers a great array of operating alternatives. Numerous and sometimes conflicting constraints are imposed on reservoir releases, elevations, and other system variables. In addition, the system and the market characteristics and the operational goals are dynamic and change over time.

To cope with the increasing complexity of the scheduling problem, a new approach that can provide guidance under current conditions, and for future situations in which past operation experience is not applicable, is needed. A hierarchy of the operational planning models could be developed in the spirit of decision analysis as elegantly described by Raiffa:

> "The spirit of decision analysis is to divide and conquer: Decompose a complex problem into simpler problems, get your thinking straight in these simpler problems, paste these analyses together with a logical glue, and come out with a program for action for the complex problem (Raiffa, 1968, p. 271)."

Chapter 4 details the structure of one of the decision support systems in the hierarchy of the operational planning models as outlined in Figure 3.11. The decision support system has been developed in the spirit of the model depicted in Figure 3.16 to accommodate the complexity of the decision making environment as discussed above, and to provide the needed (and required) link between the long and short-term operations planning for the B.C. Hydro system.

CHAPTER 4

THE DECISION SUPPORT SYSTEM

In this Chapter the objectives of developing the decision support system are outlined. Then the user's requirements and design philosophy of the system are described, followed by a brief description of its main components and structure. Then a brief description of the hydroelectric systems modeled is given. This is followed by a detailed outline of the generalized formulation of the optimization mathematical model.

4.1 OBJECTIVES OF THE DECISION SUPPORT SYSTEM

In operating a complex hydroelectric system in a competitive market environment the operational as well as the financial risks are high. Traditionally the main objective of the system operator was to secure a stable supply of electric power to meet the load demand while meeting the system's physical and operational constraints. The major driving force in making operating decisions was to ensure the availability of sufficient energy and capacity to meet the system demand while meeting the non-power requirements and operational constraints. Theoretically speaking, in a competitive electricity market industry there is always a price at which electricity can be either sold or purchased. Prices then become the major driving force in making operational decisions. Under such circumstances, any physical or operational constraints limit the ability of the system operator to exploit the full flexibility of the system and to maximize the value of the resources. The aim of the decision support system (STOM) developed in this thesis is to assist the shift and project engineers in improving the operational efficiency of the B.C. Hydro system and to make good operational and trading decisions while meeting the constraints.

4.2 USER'S FUNCTIONAL REQUIREMENTS AND DESIGN PHILOSOPHY

Two very important components of the research reported on in this thesis are the determination of the user's functional requirements and the design philosophy of the decision support system.

4.2.1 User's Functional Requirements

For STOM to be *used* effectively and reliably by its intended users in their daily operations, the following functional requirements were set out by the users:

i. *It should rely on a reliable and accurate database.* The steps that were taken to meet this requirement are discussed in Chapter 5;

ii. *It should be easy to use.* The steps taken to meet this requirement consisted of developing the Graphical User Interface, and the Results-Display Software –two of the components of the decision support system, as discussed below;

iii. *It could be run by any authorized user in the BC Hydro computer network.* The steps taken to meet this requirement consisted of developing the computer communication protocols –a component of the decision support system, as discussed below;

iv. *It should be fully integrated with the LRB system.* The steps taken to meet this requirement consisted of coordinating with the Shift Engineers and computer support personnel to insert the required modules in the LRB system to extract STOM's input data. These steps are discussed in more detail in Chapter 5. It should be mentioned that the front-end of STOM, (the GUI) was designed to be launched from the LRB system, and the Results-Display Software is fully integrated and exports the results back to the LRB system –the main "workhorse" used by the Shift Engineer;

v. *It should closely model the current status of the system.* To meet this requirement the most current information contained in the LRB system is read and transferred for use by the decision support system. Also a hydraulic simulator was developed, under the direct and close supervision of the author, to accurately portray the response of the system;

vi. *It should allow the user to dynamically select a set of plants for simulation and/or optimization studies.* To meet this requirement the Graphical User Interface allows STOM users to select the river systems and generating plants they wish to include in the simulation and optimization study. In addition, the simulation and optimization mathematical models, and the solution algorithms, both allow the user to dynamically select one or more plants for either simulation and/or optimization studies;

vii. *It should complete the study for ten plants and for 168 hours in less than three minutes.* To meet this requirement a sophisticated, state-of-the-art commercial modeling language and linear programming solver was obtained and a Windows NT network server is dedicated to run the optimization/simulation models. In addition, a fast hydraulic simulator was coded in the efficient C programming language. The linear programming model was also optimized to minimize the time required to run the model.

It should be noted that the above functional requirements were not set at the outset of the research project. They were developed iteratively through time-consuming discussion and debate, as discussed in Chapter 5.

4.2.2 Design Philosophy

STOM focuses on the user as the ultimate decision maker, who decides when to use it, how to use it, what analysis to perform with it, and whether to accept or reject its results. It was designed to give full flexibility to its user to dynamically formulate the problem they wish to solve and then solve it in the shortest time possible. The user has full control over all operational input data and the limits that form the optimization model's constraints. They also have control over some of the model's constraints, and the number of river systems and plants to be included in the simulation/optimization study. It was designed to be used as a decision support tool, to give insights into the complex nature of the decision problem, and not as potential replacement of its users. It also enables the user to select the time frame for the study, whether it is as short as one hour, or as long as 168 hours. The user also selects the objective function of the optimization process, be it to run the system to maximize efficiency or to maximize value of resources.

4.3 COMPONENTS OF THE DECISION SUPPORT SYSTEM

STOM consists of six components: the LRB System Data Preparation Procedures, Data Saving and the Software that launch the GUI, the GUI, the Communication Protocols, the Simulator, the Optimizer, and the Results-Display Software. The optimization process is designed to be carried out on two workstations (see Figure 4.1 for schematic representation of the system): a personal computer client workstation that contains the LRB system, the GUI, the results-display software, and the client's network communication protocols; and a Windows NT Server Workstation that contains the Simulator, the Optimizer, and the server's communication protocols. The following is a brief description of these components. A detailed description of the optimization mathematical model is contained in Section 4.5. Annex C lists the software programs used in STOM and gives brief details of their functions.

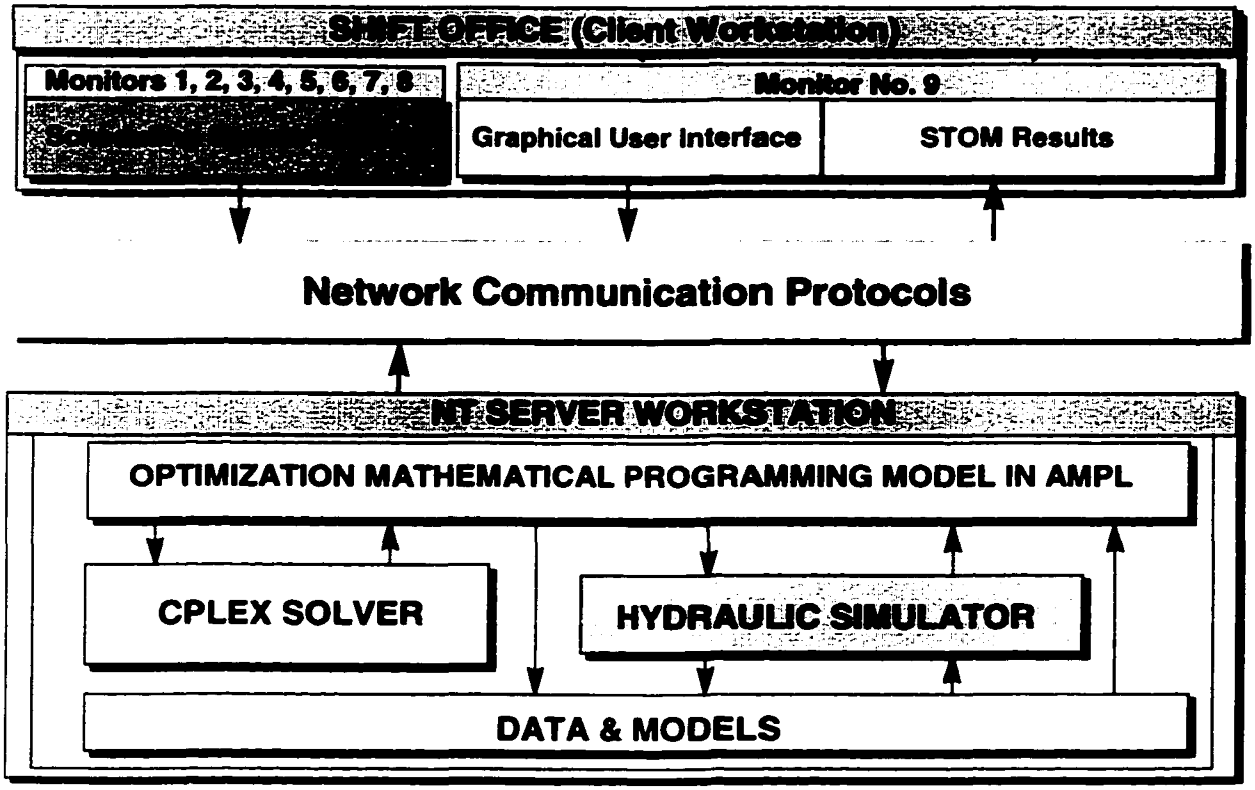


Figure 4.1. Main Design Features of STOM.

4.3.1 Data Preparation Procedures, Data Saving and GUI Launch Software

Several steps should be followed to prepare input data for the simulation and optimization study. Full details on these steps have been included in the decision support system's "User's Guide" (Shawwash et. al., 1998), and were summarized in an instruction sheet as attached in Annex B. The following is a listing of these steps:

i. Prepare the LRB System Input Data

a. Check the LRB schedules for errors in data (e.g., non-numeric inputs),
b. Verify scheduled generation limits to ensure that the generating facilities capacities are not exceeded or are not in conflict with each other,
c. Balance the LRB, to ensure that available resources could meet the load,
d. Verify the reservoir's maximum and minimum operational limits,
e. Verify the local inflows and spills for each reservoir,
f. Verify the actual reservoir water levels for errors in input data,
g. Update the unit outage schedule by running the Outage Request Form (ORF) software. Once ORF is run, a file that contains an hourly listing of a decimal representation of generating unit availability for each plant for each of the 168 hours is created.

It should be noted that the above data preparation steps are of the routine type and that data in the LRB system is regularly checked and updated by the Shift Engineer. For this reason, the above steps do not constitute additional steps that need to be taken to run the simulation/optimization study.

ii. Software to Write Input Data and to Launch the GUI

Once the data have been checked and verified, the user can initiate the simulation and optimization process by simply pressing the "STOM" button in the LRB system. Once the "STOM" button is pressed input data is automatically saved at the Client's workstation, and the GUI is automatically launched. A Visual Basic/Excel routine has been inserted in the LRB to save the required input data, and to launch the GUI. This routine also performs a check on the input data for any obvious errors, such as non-numeric inputs. The routine writes out the input data to text files in special format such that the Simulator and the Optimizer models can read them. It also contains preliminary data checking routines that check if STOM has been properly set-up to run from the LRB system. If such errors were encountered, error messages are displayed to the user identifying the source of error. If errors in input data are found, a log file is then displayed to inform the user on the type of error and its location, and the run is aborted. If STOM was not properly setup, the user is advised to contact the LRB system computer support person to solve the problem. The data-saving code writes out STOM's input data as listed in Table 4.1.

Table 4.1. STOM Input Data Saved from the LRB System

Contents (Number of hours or data records)
Domestic Load on the BC Hydro System (168 Hourly values)
Scheduled Total Imports (168 Hourly values)
Scheduled Total Exports (168 Hourly values)
Plant Maximum Generation Capacities (168 Hourly values/plant)
Plant Minimum Generation Limits (168 Hourly values/plant)
Plant scheduled Generation (168 Hourly values/plant)
Reservoir Actual/Forecast Forebay levels (168 Hourly values/plant)
Reservoir inflows (168 Hourly values/plant)
Reservoir Spills (168 Hourly values/plant)
Special and fish releases (168 Hourly values/plant)
Spill releases through controlled gates (168 Hourly values/plant).
Breakdown of the Imports/Exports and potential or actual net spot sales (168 hours for each type of exchange)
Marketing information, listing the hourly spot prices and tie line capacities for the Alberta and the US markets (168 Hourly values/market.
Thermal generation input parameters and limits.
Physical and operational upper and lower reservoir forebay levels.
Combo number, representing the units availability in each plant (168 Hourly values/plant)

4.3.2 The Graphical User Interface

To arrive at the right design and functionality for a Graphical User Interface (GUI) the users must be fully involved in its design, and their requirements must be taken into account. Thus the GUI was designed and implemented in very close coordination with its users, as described in Chapter 5. To make STOM easy to use and to be responsive to user's needs and requirements, several functional features were included in the GUI to ease the following tasks for the user:

- Select the river systems to be included in the simulation/optimization study;
- Select the plants to be included in the optimization study;
- Confirm the initial reservoir's forebay elevations;
- Set the study date and the starting hour and the number of hours for the study;
- Select the objective function for the optimization run;
- Review marketing information: forecast spot prices, transmission tie-line limits;
- Review marginal value of energy and target elevations for reservoirs;
- Set operating reserve and regulating margins;
- Set additional, optional, operational constraints and limits; and
- Launch the simulation/optimization process.

To make the process user friendly, the GUI is coded in Visual Basic and is launched from a button in the LRB system, as described in Section 4.3.1. Computer coding of the GUI in

Visual Basic was initially carried out by a group of Electrical Engineering/Computer Engineering students, from U.B.C., who also developed the communication protocols as part of the requirements for EE 475 fourth-year course project (Hwang et. al., 1998). Since its original design, several revisions were required to reflect user's preferences and requirements. Figure 4.2, illustrates the front-end of the current version of the GUI. A detailed description of the its main functional features is attached in Annex D.

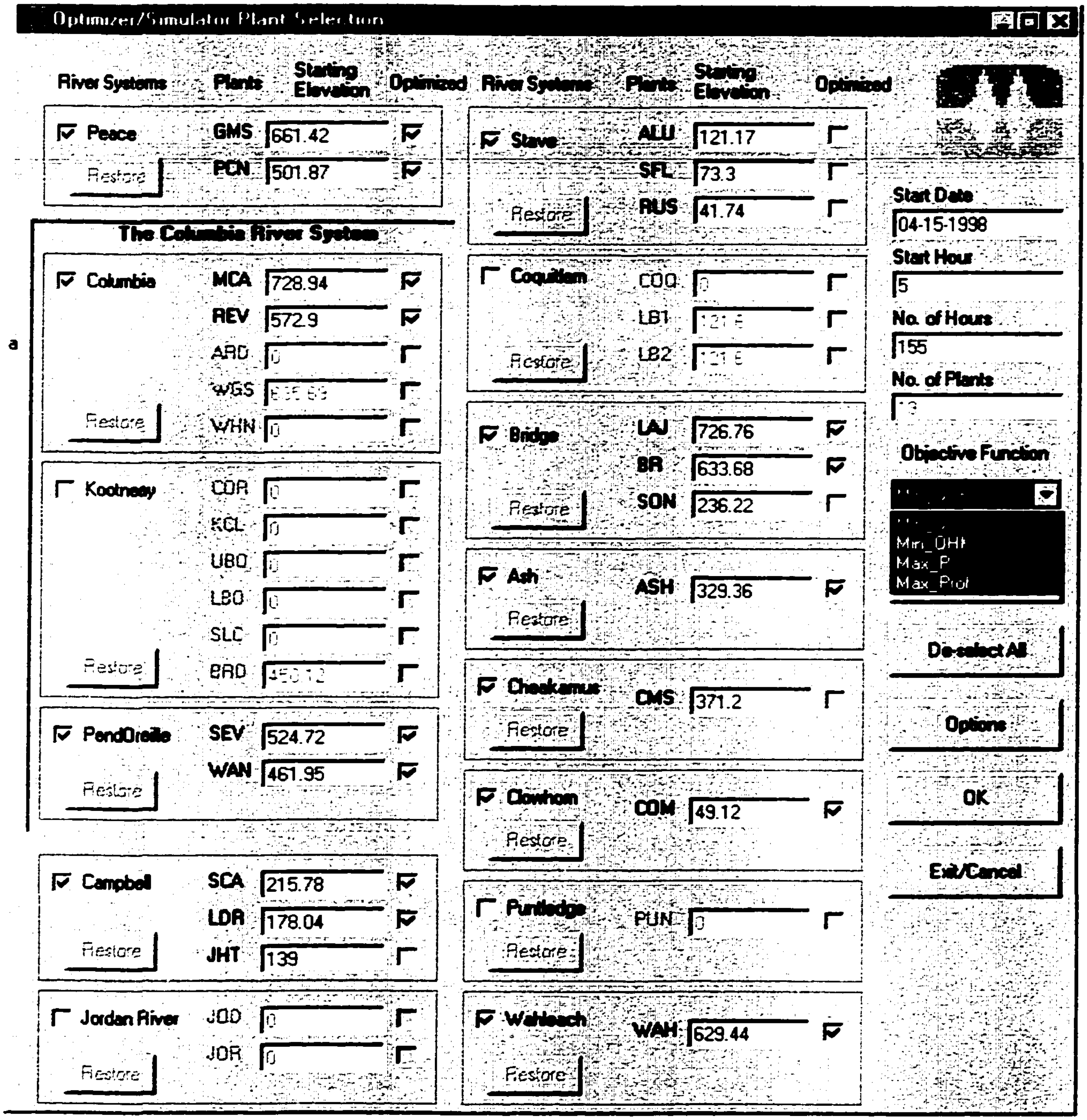


Figure 4.2. STOM Graphical User Interface

4.3.3 The Communication Protocols

As outlined by the user's functional requirements, it was required that STOM could be run by any authorized user in the B.C. Hydro computer network. The rationale behind this requirement is that running the simulation/optimization process on the workstation, which contains the LRB system, is impractical, for several reasons. First, to run the LRB system, considerable workstation system resources are required and therefore, a single workstation was incapable of efficiently handling the complex mathematical models developed. Second, the optimization process is a time- and memory-consuming process, and therefore it was not tolerable for the LRB workstation to be occupied exclusively by the simulation/optimization process for any length of time. Third, the method of launching STOM is at a DOS prompt, while the LRB is running in the Windows 95 environment. Switching between environments is time consuming and cumbersome and could hinder the stability of the workstation. Fourth, the Shift Office is located in two different buildings (Edmonds and Downtown). To enable the Shift Engineer to run STOM from wherever he is located, it was required that a central server be used to run the simulation/optimization process. Fifth, future developments of STOM entails use of the system by many other users (project planning engineers) who have access to the B.C. Hydro computer network.

A solution was needed to the problem of distributing the computation workload over the network-computing environment. In consultation with the B.C. Hydro computer network engineers and the end-users of STOM, the solution arrived at was to design STOM in such a way as to launch the simulation/optimization process from the client (LRB) workstation and run the simulation/optimization models on a dedicated network server. Once the Shift Engineer submits the run, they can continue with other tasks while waiting for the results to be formatted and displayed at the LRB workstation. The above requiremens necessitated development of two communication protocols: the client, and the server communication protocols.

The communication protocols are coded in C and Visual C++ to perform remote procedure calls, to transfer input and output data, and to initiate and terminate the optimization process. The communication protocols automatically transfer input data and commands between the client workstation and the NT Server workstation (see Figure 4.1 for layout). Once the client communication protocol is activated by the GUI, it compresses input data files generated by the LRB system and the interface, and it then calls the NT Server by utilizing a remote procedure call. If the NT Server and the CPLEX software are available, then the client's protocol transfers the data and signals the server's communication protocol.

However, if the NT Server is not available it queues the call and keeps trying until the NT server is freed from other runs, or it terminates after several trials if the Server was not available. The client's communication protocol is kept running at the client's workstation waiting for a signal from the server protocol. Once signaled, the server's communication protocol issues two instructions. The first instruction is to decompress the client's input data and distribute it into designated directory structure at the NT Server. The second instruction passes a DOS argument that launches the AMPL modeling session and invokes a script text file, which relates to the objective function selected by the user, in the AMPL syntax. At the NT Server, the overall process is controlled by the AMPL modeling language (Fourer, 1993). Once the simulation/optimization process is complete (when the AMPL session ends), the Server's communication protocol calls the client workstation, compresses and transfers output data. When the transfer is complete, the client's protocol takes over, launches the Results-Display Software and then terminates itself. For more details on implementation considerations with the communication protocols see Chapter 5.

B.C. Hydro currently holds a one-user license for AMPL and CPLEX software systems. For this reason, if more than one client attempts to simultaneously access the NT Server, a signal is sent to the client's protocol to indicate that the server side is busy performing an optimization run or is unavailable, if the server has been taken out of service. The client's protocol tries to reestablish connection with the NT Server for up to ten times with 10 seconds intervals between each attempt. If the server is still busy, it then quits, and informs the user that the server is not available. The communication process log is saved to a text data file that contains the activities carried out by the protocols, and can be accessed for debugging purposes.

One other important design feature of the communication protocols is that they are portable to any client, or network server workstation that supports remote procedures calls. This has been accomplished by requiring that the protocols be machine independent, and that the communication procedures and default settings are all specified by default configuration files.

The communication protocols were developed by a team of students from the Electrical Engineering Department/Computer Engineering, U.B.C., as fourth year project for their EE 475 course, under the supervision of Dr. W. G. Dunford. Further technical details on the communication protocols can be found in Hwang et al., (1997).

4.3.4 The Hydraulic Simulator

As outlined by the user's functional requirements, it was required that STOM should closely model the current status of the system and that it should complete the simulation/optimization run in the shortest time possible. To satisfy these requirements and B.C. Hydro's needs, the hydraulic simulator (Ristock et. al., 1998) was developed in house under the direct supervision of the author and B.C. Hydro operations engineers. Work on the simulator started at the early stages of the research project. The early stages involved collection and screening of physical input data, and developing an understanding of the hydraulic properties of the hydroelectric systems modeled. Later stages included coding the simulator in the C programming language and improving its accuracy and algorithmic correctness. More details on development and implementation of the simulator can be found in Chapter 5.

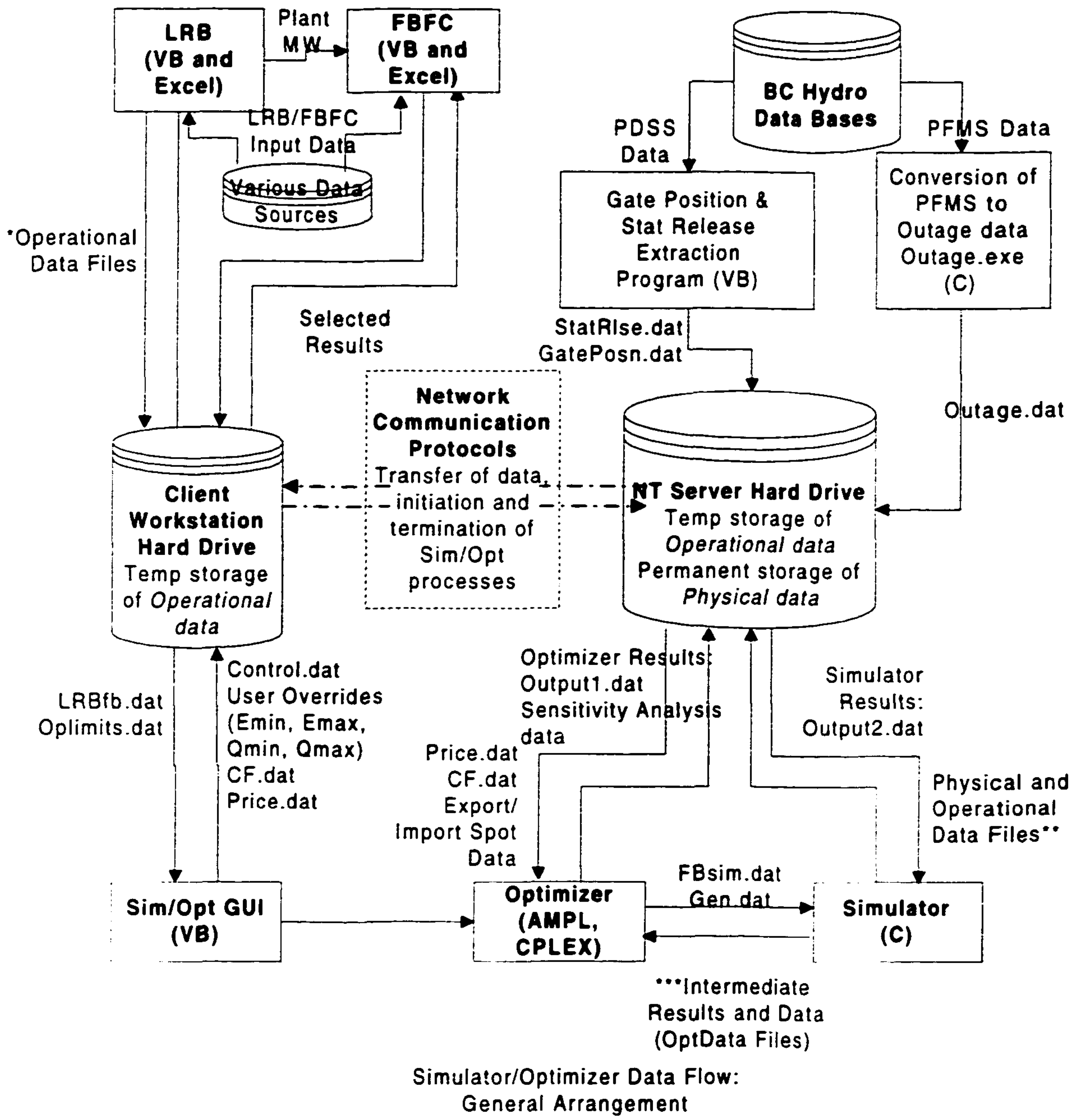
The simulator follows a modular design in that each of its main routines are included in a separate module. Several modules are linked to form a coherent single application: the simulator. This feature allowed easier debugging and modification to the cumbersome and extensive C code. It also allowed some modules to be easily adapted for other applications and uses within B.C. Hydro. For example the module that calculates plants' generating capacity was later integrated into the LRB system to calculate the capacities of generating plants as a function of their forebay elevations.

The hydraulic simulator models the hydraulic system and calculates the physical and operational limits of the hydroelectric facilities. For each hour in the study, it hydraulically models upstream inflows and outflows using the mass balance equation for each reservoir. Inflows can be of any combination: upstream spills, turbine flows, and local river or tributary inflows. Outflows consist of turbine, spill or special release outflows (e.g., required fish and other releases). It then computes the resulting storage and converts it to forebay elevation at the end of each hour using storage elevation tables. The simulator also calculates maximum and minimum turbine discharges and maximum generating capacity for each plant. It also performs checks on elevation, discharge, and generation to determine if any operational or physical limits have been violated.

The simulator can run as a solo application (i.e., without the Optimizer) if no plants are selected for optimization in GUI. This feature allows the Shift Engineer to simulate the response of the hydraulic system to generation schedules and determine forebay elevations as well as generation and discharge limits. The simulator writes out the simulation and optimization results to a text output file that is transferred for display by the Results-Display Software.

Figure 4.3 illustrates sources of data and the links of the simulator to other components of the decision support system and to other B.C. Hydro information systems. The simulation algorithm is illustrated in Figure 4.4, and is outlined in Annex A.

The simulator was developed by a number of graduate students and research assistants from the Civil Engineering Department, U.B.C., under direct supervision of the author and operations engineers at B.C. Hydro. Further technical details on the simulator can be found in Ristock et al., (1998).



Source: Ristock et. al., 1998

Figure 4.3. Simulator/Optimizer Data Flow General Arrangement

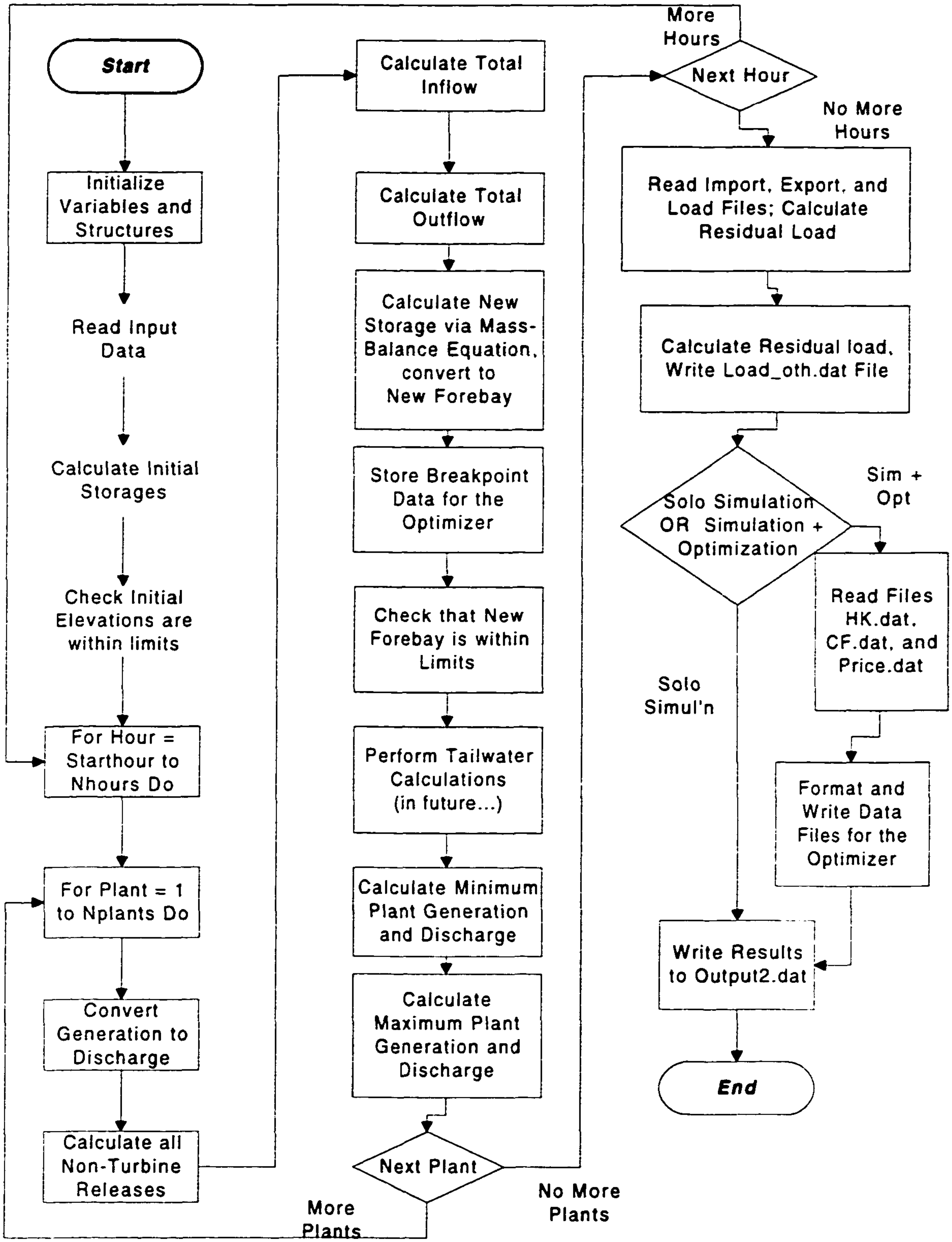


Figure 4.4. The Simulator Algorithm Flowchart.

Source: Ristock et. al., 1998.

4.3.5 The Optimizer

The Optimizer uses linear programming techniques with two software packages: the AMPL (Fourere, 1993) mathematical programming language, and the CPLEX solver (ILOG, 1998). Details on the mathematical programming formulation, the AMPL modeling language (Fourer et. al., 1993), the CPLEX solver, and the solution algorithm can be found in Section 4.5.

4.3.6 The Results-Display Software

As outlined by the User's Functional Requirements, it was required that STOM should be fully integrated with the LRB system, and that it should be easy to use. The Results-Display Software achieves part of these requirements. The Results-Display Software has undergone several phases of development as discussed in Chapter 5. All Shift Engineers have participated in the design of the graphic displays and in selecting the format of output data. The software is coded in Visual Basic for Excel to be compatible with the LRB system. It is designed to be launched by a simple Visual Basic program that is activated once the client's communication protocol receives the signal from the NT Server communication protocol that the simulation/optimization run has been completed.

The Results-Display Software consists of several spreadsheets: the generation summary, the individual plant sheets, the numeric output results from the simulator and the optimizer, and a sheet that displays the optimal unit commitment used in the optimization process (See Annex F for graphic displays). The generation summary sheet lists the optimized generation schedules for all optimized plants in the study. It also lists the residual generation from all other plants along with prescheduled exports and imports, and the energy gain (as compared to the LRB schedule) resulting from the optimization run. These indicators are used as measures of the effectiveness of the optimization run, and are dependent on the objective function chosen by the user. For example if the user has selected the maximum efficiency objective function, then the energy gain measures the difference in energy use between the LRB schedule and the optimizer schedule. The energy gain in this objective function represents the amount of energy stored in reservoirs as a result of running the optimization routine. If, however, the objective function was to maximize energy production while fixing reservoir storage levels to those scheduled by the LRB, then the extra power gained would represent the extra energy that could be generated and probably sold in the market with the same amount of water used.

If the maximum profit objective function is used, energy gains (or losses) represents both the gains in energy as a direct result of improved system efficiency and from increased (or decreased) energy transactions. Under this objective function the summary sheet also lists the optimized net trading transactions to Alberta and to the U.S., along with other data.

In the summary sheet, several graphic displays gives the user the feel of the distribution of the optimized generation as well as the prescheduled and optimized trading schedules, and the residual and total domestic load. In addition, another graphic display illustrate the gainers and the losers in total generation over the optimization run. If the "Maximize Profit" objective function was used, an additional graphic display illustrates the distribution of spot prices and the optimized net spot sales in the U.S. and Alberta markets, in one display.

In addition to the summary sheet, for each plant included in the simulation/optimization run a separate sheet is dynamically created to numerically and graphically display the output results. For each plant the output data, shown in Table 4.2, is listed and charted for each hour in the study for the user to review. To make it easier for the user to quickly assimilate output data, a coloring scheme, has been used to indicate the optimized, LRB scheduled or actual data (when historic schedules are used). It was found that these made it much easier for the Shift Engineer to quickly identify the differences between the LRB and the optimized schedules. It also makes assimilation of the massive amount of data easier for the user. The other advantage of having a separate sheet for each plant is that the user can quickly move from one plant to the other to compare details of the generation schedule for different plants, or to display charts for two plants simultaneously. The users rarely use the sheets that contains the numeric output results, but they were kept to assure users that output from the simulation/optimization models is directly available if needed.

In addition to providing a user-friendly display environment, the Results-Display Software is equipped with other features to make it easier for the Shift Engineer to navigate individual sheets. For example, to move from the chart that displays the forebay levels, all the user has to do is to click on the chart itself or on a button to display the generation schedules chart, and again to display the total plant discharge chart. In addition, a chart-zoom facility has been provided to scale the chart's axes to display finer details of the output data. These issues may seem trivial to most people, but they were found to be very important in getting the decision support system accepted and used by the very busy operations engineers working a 12-hour day and night shifts.

In addition to scheduling generation for plants, the Shift Engineer is also responsible for deciding which units are to be switched on or off at each plant and for each hour. To aid the Shift Engineer in this task, the Results_Display software contains a sheet that lists the optimal unit commitment used by STOM to define the generation production function (see Section 4.5 and 4.6 for more details). This display helps the Shift Engineer to compare STOM's results with those from other unit commitment software systems (e.g., the Static Plant Commitment Program (SPUC) and the Dynamic Unit Commitment (DUC)) used to dispatch units in real time operations.

Table 4.2. Output Results Displayed to the User

Plant ID Name
Hour
Optimized Generation (MW)
LRB Generation (MW)
Minimum Generation (MW)
Maximum Generation (MW)
Optimized Forebay Elevation (M)
LRB Forebay Elevation (M)
Actual/Calculated Reservoir Level (M)
Minimum Forebay Elevation (M)
Maximum Forebay Elevation (M)
Optimized Plant Discharge (CMS)
LRB Plant Discharge (CMS)
Optimized Turbine Discharge (CMS)
LRB Turbine Discharge (CMS)
Minimum Plant Discharge (CMS)
Maximum Plant Discharge (CMS)
Local Inflow (CMS)
Total Inflow (CMS)
Spill (CMS)
Total Outflow (CMS)

4.4 HYDROELECTRIC SYSTEMS MODELED

The current version of the decision support system provides the optimal hourly generation schedule for the river systems and hydroelectric facilities listed in Table 4.3.

Table 4.3. River Systems, Reservoirs and Plants Modelled

River System	Plants	Generation Capacity (MW)
The Peace	G. M. Shrum (GMS), Peace Canyon (PCN)	3,430
The Columbia	Mica (MCA), Revelstoke (REV)	3,840
The Pend D'Oreille	Seven Mile (SEV), Waneta (WAN)	954
The Stave	Alouette (ALU), Stave Falls (SFL), Ruskin (RUS)	163
The Bridge	Lajoie (LAJ), Bridge (BR), Seton (SON)	548
The Cheakamus	Cheakamus (CMS)	155
The Clowhom	Clowhom (COM)	33
The Wahleach	Wahleach (WAH)	60
The Campbell	Strathcona (SCA), Ladore (LDR), John Hart (JHT)	229
The Ash	Ash (ASH)	27
Total		9,439

These represent approximately 83% of the total generating system capacity (hydro and thermal), and about 91% of the total hydroelectric system (see Table 3.1 for comparison). The only three major hydroelectric systems that are not currently modeled by STOM are the Kootenay Canal (528 MW), the Jordan River (170 MW), and the Buntzen (72 MW) systems. The main reasons for not including these are the unavailability of operational input data required and incomplete representation in the hydraulic simulator. However, once the operational input data and the algorithm to hydraulically simulate these systems are available, it will be very easy to include them in the optimization model. Annex G contains a brief description of the main operational features of the hydroelectric systems currently modeled by STOM.

4.5 MATHEMATICAL MODELING OF GENERATING FACILITIES

Considerable thought, discussion, study and analysis was conducted before the generalized mathematical model described herein was formulated. It involved issues such as the nature and complexity of the hydroelectric systems to be modeled, user's expectations and their functional requirements, the goal of the decision support system and how it will be used in real-time operations. It also included consideration of how the model could evolve to consider other modeling aspects that B.C. Hydro may wish to include in the future. The main dilemma was how to build a model that could be formulated dynamically without having to significantly revise its structure every time the user wished to run a different combination of river systems or for a different study duration. These issues are addressed in Chapter 5. However, one can easily realize the great benefits from formulating a generalized model. The mathematical model described herein exploits recent advances in the algebraic modeling languages by formulating the model in a semi-network structure as outlined below.

4.5.1 Hydraulic Modeling of Reservoir Operations

i. Representation of Hydroelectric Facilities

A typical hydroelectric generation system consists of sets of rivers, tributaries, reservoirs, powerhouses and additional hydraulic facilities such as intake structures, spillway gates and weirs, as described in Annex G. A river system may contain one or more generating facilities that could be connected serially or in parallel. Serially connected facilities are hydraulically connected, because discharges from a hydroelectric facility constitute a part of the inflows to the downstream facilities. River System Type II and River Systems Type I in Figure 4.5 illustrates this. Two river systems could also be hydrologically coupled, because discharges from one facility in one river system could constitute some of the inflows to one or more facility in other river system as illustrated in Figure 4.5 for River Systems Type I. In addition to hydrologic coupling, hydroelectric facilities are coupled dynamically from one time period to the next, because decisions on flow releases made at any time period and location affects decisions on flows in other time periods and at other locations in the study. Inflows to reservoirs may be natural or modified by the operation of an upstream plant. Aside from hydropower generation, hydroelectric facilities are also operated to satisfy discharge requirements according to certain rules that are set by environmental, regulatory, navigation, and long-term planning requirements, as discussed in Section 3.3, and Section 4.4. Figure 4.5 illustrates a typical setup of rivers and reservoirs for a hydroelectric generating system containing two river systems.

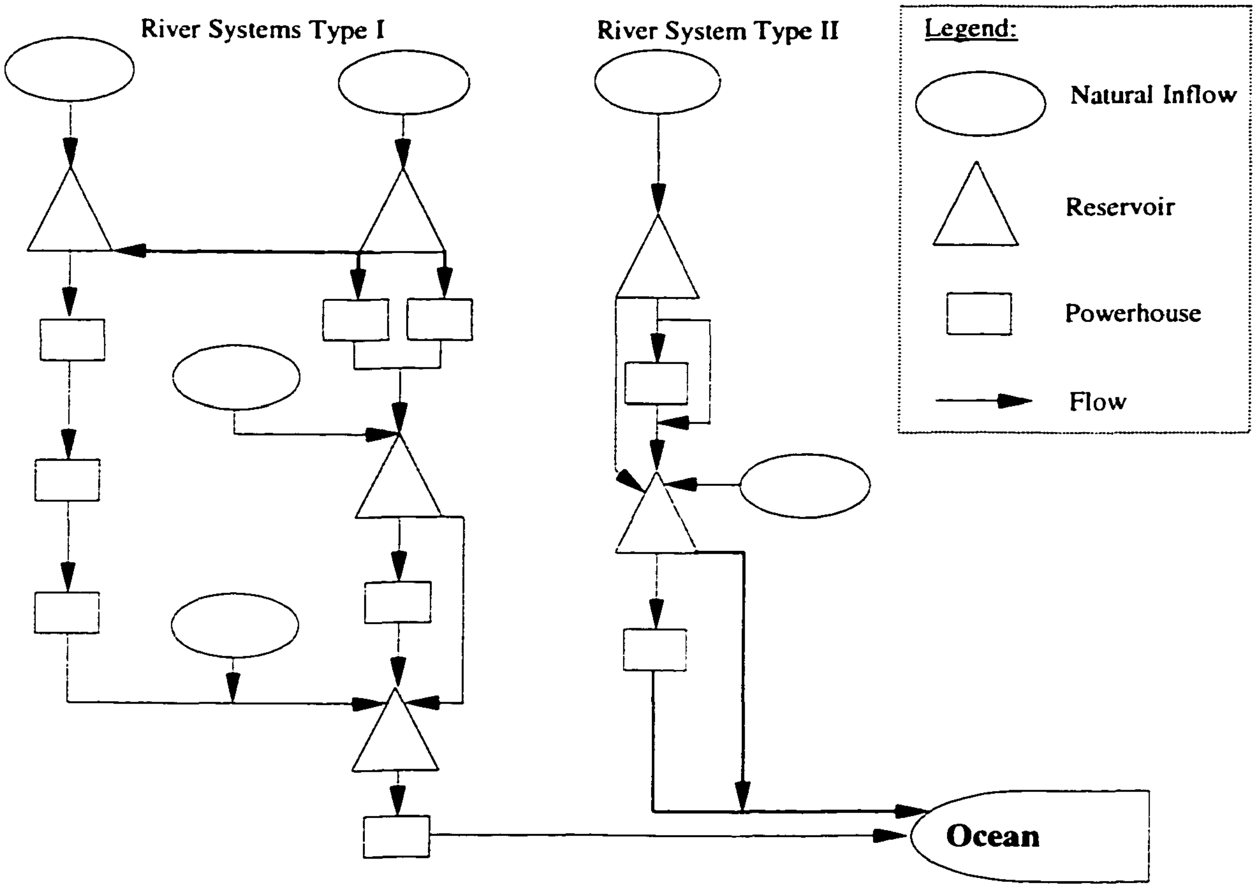


Figure 4.5. Schematic of Typical River Systems with Reservoirs and Hydroelectric Facilities.

To capture the complex nature of inflows to and from reservoirs in the B.C. Hydro system, a matrix structure has been used to describe flow sources and destinations. Several incidence matrices were used to describe the turbine and spill discharges and inflows from or to reservoirs as follows. The QTR_{jk} and QSR_{jk} matrices describes the turbine and spill flows from hydroelectric facility j to hydroelectric facility k ($j \in J$, $k \in K$: $j = k$). The index k represents the rows in the matrix while j represents the columns. Other matrices were used to describe the turbine UQT_{jk} and spill UQS_{jk} hydroelectric facility's inflows from facility j to facility k ($j \in J$, $k \in K$: $j \neq k$). An entry of '1' in the matrices indicates that a physical flow occurs from or between reservoirs, while '0' indicates no flows.

These simple, yet powerful, descriptions of the system have allowed modeling of very complex patterns of flows between reservoirs. It also allowed the model to be formulated dynamically as will be discussed in Chapter 5 (Section 5.1 and 5.2).

QTR_{jk} =

$$\begin{array}{c|cccccc} & j & j+1 & j+2 & \cdots & J-1 & J \\ \hline k & 1 & 0 & 0 & \cdots & 0 & 0 \\ k+1 & 0 & 1 & 0 & \cdots & 0 & 0 \\ k+2 & 0 & 0 & 1 & \cdots & 0 & 0 \\ \vdots & \vdots & \vdots & \vdots & \ddots & \vdots & \vdots \\ K-1 & 0 & 0 & 0 & \cdots & 0 & 0 \\ K & 0 & 0 & 0 & \cdots & \vdots & 1 \end{array} \qquad (4.5.1.1)$$

QSR_{jk} =

$$\begin{array}{c|cccccc} & j & j+1 & j+2 & \cdots & J-1 & J \\ \hline k & 1 & 0 & 0 & \cdots & 0 & 0 \\ k+1 & 0 & 1 & 0 & \cdots & 0 & 0 \\ k+2 & 0 & 0 & 1 & \cdots & 0 & 0 \\ \vdots & \vdots & \vdots & \vdots & \ddots & \vdots & \vdots \\ K-1 & 0 & 0 & 0 & \cdots & 1 & 0 \\ K & 0 & 0 & 0 & \cdots & \vdots & 1 \end{array} \qquad (4.5.1.2)$$

In the QTR_{jk} matrix shown above, the index j and k represents the same facility, which gives rise to a square matrix. A turbine outflows from facilities j, $j+1$, and J are also discharged from facilities k, $k+1$, and K respectively. As the value in the matrix that corresponds to facility (J-1, K-1) is "0" in QTR_{jk}, there is no turbine discharge from the facility. A similar matrix was used to describe spill discharges from hydroelectric facilities, QSR_{jk}. Note that there are spills from plant (J-1, K-1), since the corresponding value in the QSR_{jk} matrix is "1".

UQT_{jk} =

$$\begin{array}{c|cccccc} & j & j+1 & j+2 & \cdots & J-1 & J \\ \hline k & 0 & 1 & 0 & \cdots & 0 & 0 \\ k+1 & 0 & 0 & 0 & \cdots & 0 & 0 \\ k+2 & 0 & 0 & 1 & \cdots & 0 & 0 \\ \vdots & \vdots & \vdots & \vdots & \ddots & \vdots & \vdots \\ K-1 & 0 & 0 & 0 & \cdots & 1 & 1 \\ K & 0 & 0 & 0 & \cdots & \vdots & 0 \end{array} \qquad (4.5.1.3)$$

UQS_{jk} =

$$\begin{array}{c|cccccc} & j & j+1 & j+2 & \cdots & J-1 & J \\ \hline k & 0 & 0 & 0 & \cdots & 0 & 0 \\ k+1 & 0 & 1 & 0 & \cdots & 0 & 0 \\ k+2 & 0 & 0 & 1 & \cdots & 0 & 0 \\ \vdots & \vdots & \vdots & \vdots & \ddots & \vdots & \vdots \\ K-1 & 0 & 0 & 0 & \cdots & 1 & 0 \\ K & 0 & 0 & 0 & \cdots & \vdots & 1 \end{array} \qquad (4.5.1.4)$$

Matrices describing a facility's upstream inflows (excluding stream inflows) are arranged similar to those in facility's outflows. Note that the facility's inflows can originate from one or more facilities in the system. For example, in the UQT_{jk} matrix, facility K-1 receives turbine discharges that originates from facility J-1 and J, while facilities $k+1$ and K receives no upstream turbine discharges.

ii. Modeling Turbine and Spill Operations

Total spills from a reservoir at time step t consist of fixed (QSF_{kt}, $t \in T$), spills and variable spills (QS_{kt}). Fixed spills satisfy regulatory and non-power requirements, while variable spills depend on the reservoir's storage level, and are expressed in the model as a piecewise linear penalty function of the reservoir's storage (S_{kt}) as follows:

$$QS_{kt} = f(S_{kt})\,. \qquad (4.5.1.5)$$

The spill characteristic for a reservoir is modeled as a one or more segment piecewise linear curve, as shown in Figure 4.6. The number of segments depends on the physical characteristic of the free spill structure (free spill weir or spillway structures), or could be specified by the user to reflect a certain spill policy once a reservoir is at a certain storage level. The AMPL modeling language facilitates concise description of such piecewise linear

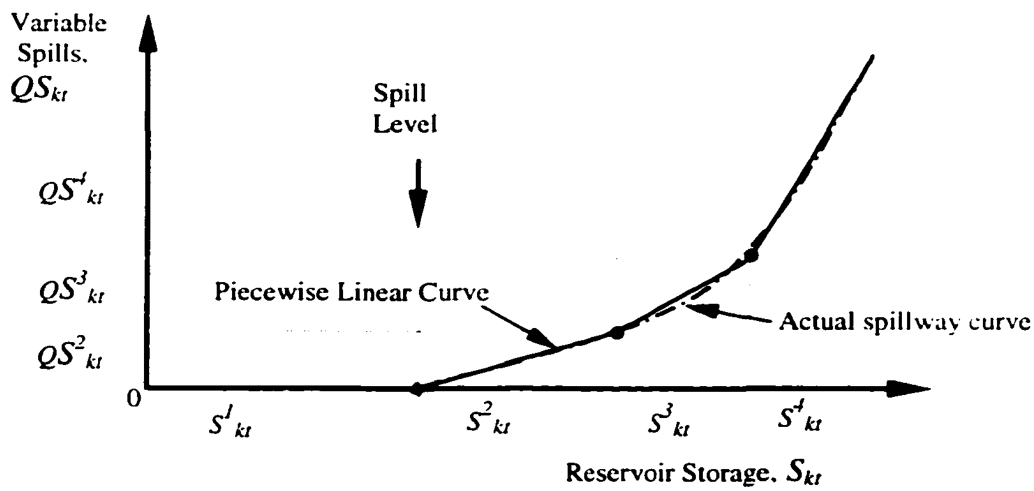


Figure 4.6. Spill Characteristics for Storage Reservoirs

functions, as described in Annex G. The spill characteristic described in Figure 4.6 indicates that as long as the reservoir is within the first storage zone, S^1_{kt}, there will be no spills. However, once the reservoir storage increases above the first storage zone, the slope of the piecewise linear curve that corresponds to the S^2_{kt} segment will determine discharges in the QS^2_{kt} spill zone. In the AMPL modeling language, the user specifies the slope of the segments, the breakpoints of the piecewise linear curve in the reservoir storage axis, and the intercept of the curve with the spill axis in one equation. Such concise descriptions of piecewise linear functions makes approximating such non-linear, convex, relationships very convenient for generalized model representation.

Turbine and spill variable flows from a reservoir at time step t (RT_{jkt}, RS_{jkt}) are directly substituted in the model by the turbine (QT_{kt}) and spill discharges,

$$RT_{jkt} = QT_{kt} * QTR_{jk}\ , \tag{4.5.1.6}$$

$$RS_{jkt} = (QS_{kt} + QSF_{kt}) * QSR_{jk}\ . \tag{4.5.1.7}$$

Similarly, the turbine and spill inflows to a reservoir (UT_{jkt}, US_{jkt}), are directly substituted in the model,

$$UT_{jkt} = QT_{kt} * UQT_{jk} \tag{4.5.1.8}$$

$$US_{jkt} = (QS_{kt} + QSF_{kt}) * QSR_{jk}\ . \tag{4.5.1.9}$$

Direct substitution of variables and parameters is an important feature of the AMPL modeling language, as discussed in Section 4.1. It reduces the problem size and accelerates the solution time required to solve the problem considerably.

Turbine and spill discharges could be limited by maximum turbine and spill discharges (QT^{Max}_{kt}, QS^{Max}_{kt}), and minimum (QT^{Min}_{kt}, QS^{Min}_{kt}) allowable limits. These limits are represented in the model as,

$$QT^{Min}_{kt} \le QT_{kt} \le QT^{Max}_{kt}\ , \tag{4.5.1.10}$$

$$QS^{Min}_{kt} \le (QSF_{kt} + QS_{kt}) \le QS^{Max}_{kt}\ . \tag{4.5.1.11}$$

In addition, the total discharge from a plant could be limited by the maximum (QP^{Max}_{kt}) and minimum (QP^{Min}_{kt}) plant discharge limits. These limits are represented in the model as,

$$QP^{Min}_{kt} \le QP_{kt} \le QP^{Max}_{kt}\ . \tag{4.5.1.12}$$

where (QP_{kt}) is the total plant discharge, which is modeled as,

$$QP_{kt} = QT_{kt} + QS_{kt} + QSF_{kt}\ . \tag{4.5.1.13}$$

The plant discharge limits are either specified by the user (in the GUI), or are the results of other operational constraints that are calculated by the simulator and used in the optimization model. For example, the simulator calculates the minimum plant discharge limit by taking the maximum value of the following limits:

- the total of minimum turbine discharge, that corresponds to the minimum plant generation, and the fixed spills (QSF_{kt}),
- the minimum plant discharge, if specified by the user in the GUI,
- the minimum plant discharge as specified by the system operating order, which is a document that specifies the operational rules to be followed by the hydroelectric system operator. These includes consideration of minimum fish and fish habitat flows, channel hydraulics and stability (e.g., during ice formation in the Peace River), as well as for environmental (e.g., dilution of contaminants) and aesthetic reasons.

The simulator also calculates the maximum plant discharge limit by taking the minimum value of the following limits:

- the total of maximum turbine discharge, that corresponds to the maximum plant generation, and the fixed spills (QSF_{kt}),
- the maximum plant discharge, if specified by the user in the GUI,
- the maximum plant discharge as specified by the system operating order. These include consideration of maximum fish and fish habitat flows (e.g., to prevent damage to fish eggs during the spawning season), channel hydraulics and stability (e.g., scour), as well as for environmental (e.g., flooding of wet areas), aesthetic and flood control reasons.

iii. Modeling Reservoir Operations

The hydraulic continuity equation for a typical reservoir storage in m^3/s-day, and for natural river inflows (NRI_{kt}), turbine and spill flows in m^3/s, can be written,

$$S_{k(t+1)} = S_{kt} + (-\sum_{j=1}^{J} RT_{jkt} - \sum_{j=1}^{J} RS_{jkt} + \sum_{j=1}^{J} UT_{jkt} + \sum_{j=1}^{J} US_{jkt} + NRI_{kt}) / 24 . \quad (4.5.1.14)$$

The upper and lower reservoir storage constraints limit the storage variable to the range bounded by the maximum ($S^{Max}{}_{kt}$) and minimum ($S^{Min}{}_{kt}$) allowable storage levels (see Figure 4.7), and is modeled as,

$$S^{Min}{}_{kt} \leq S_{kt} \leq S^{Max}{}_{kt} . \quad (4.5.1.15)$$

As discussed in Section 4.3.2, the GUI allows the user to interactively impose a set of additional optional constraints in the model. One such constraint is used to fix the reservoir's storage at the last time-step (T) to the planned storage level ($S^{LRB}{}_{kT}$), which is determined by simulating the LRB generation and reservoir's inflows and outflows,

$$S_{kT} = S^{LRB}{}_{kT} . \quad (4.5.1.16)$$

The forebay level of reservoirs (FB_{kt}) can be expressed as a function of reservoir storage as illustrated in Figure 4.7, and is modeled as,

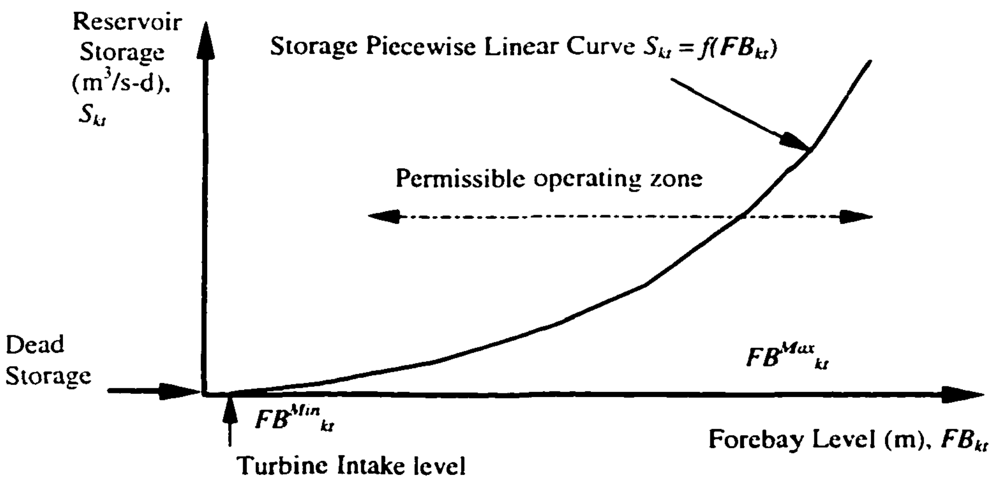


Figure 4.7. Forebay Level as a Function of Storage

$$FB_{kt} = f(S_{kt}) . \quad (4.5.1.17.a)$$

Alternatively, reservoir storage can be expressed as a function of the plant forebay as illustrated in Figure 4.8, and described in the model as,

$$S_{kt} = f(FB_{kt}). \qquad (4.5.1.17.b)$$

Equations (4.5.1.17.a) and (4.5.1.17.b) are expressed in the model as piecewise linear functions as illustrated in Figure 4.7 and 4.8. The advantage of using piecewise linear functions is that no discrepancies are introduced when converting from storage to forebay levels and visa versa, particularly for reservoirs with small storage capacities and high inflows. The storage-elevation curves used in STOM were derived from tables in B.C. Hydro's physical characteristics database. It should be noted that the above storage-elevation curves are not explicitly included in the optimization model, but they are used in the solution algorithm as described in Section 5.1.

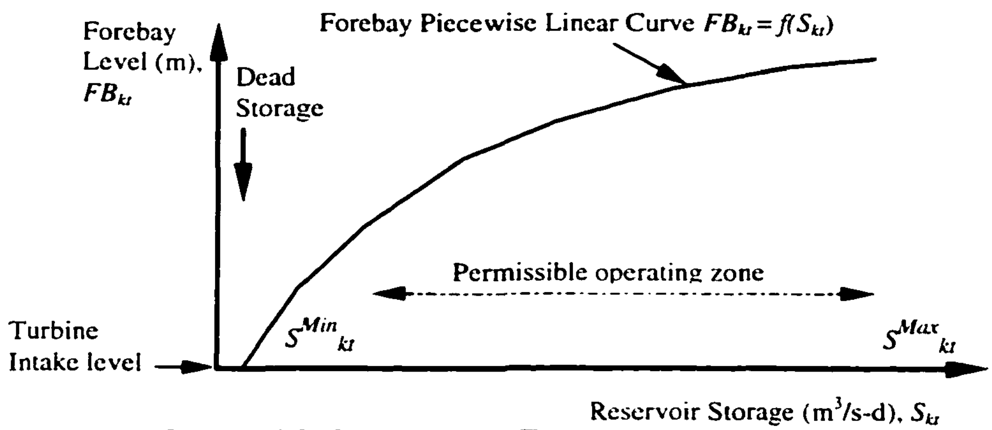


Figure 4.8. Storage as a Function of Forebay Level

4.5.2 *Modeling Hydropower Generation*

i. Basic Concepts

The main source of electrical energy generated by B.C. Hydro is the energy of water. Water stored in reservoirs and flowing in streams and rivers is passed to turbines through penstocks, gates or valves. Turbines convert the kinetic energy of water into mechanical energy that is, in turn, converted to electrical energy by generators, which is then carried to customers through a transmission and distribution network, and to neighboring utilities through tie transmission lines. Generators are used for two primary control functions: power generation and frequency control. Generators can be equipped with an automatic feedback control system to regulate them to control frequency and load. Figure 4.9, is a block diagram representation of the main components of a power generation and control system.
Several sophisticated equipment and computer models are used to control the operation of the transmission and distribution systems. These models, however, do not concern the research reported on in this thesis. Research in this thesis is concerned with the components that have an effect or are closely tied to the water energy supply systems, and some parts of the generating and electrical systems, as indicated in Figure 4.9. Other components of the electric and generation systems are thoroughly covered by many textbooks in the fields of electrical (Kundur, 1993) and hydropower engineering (Warnick, 1984).

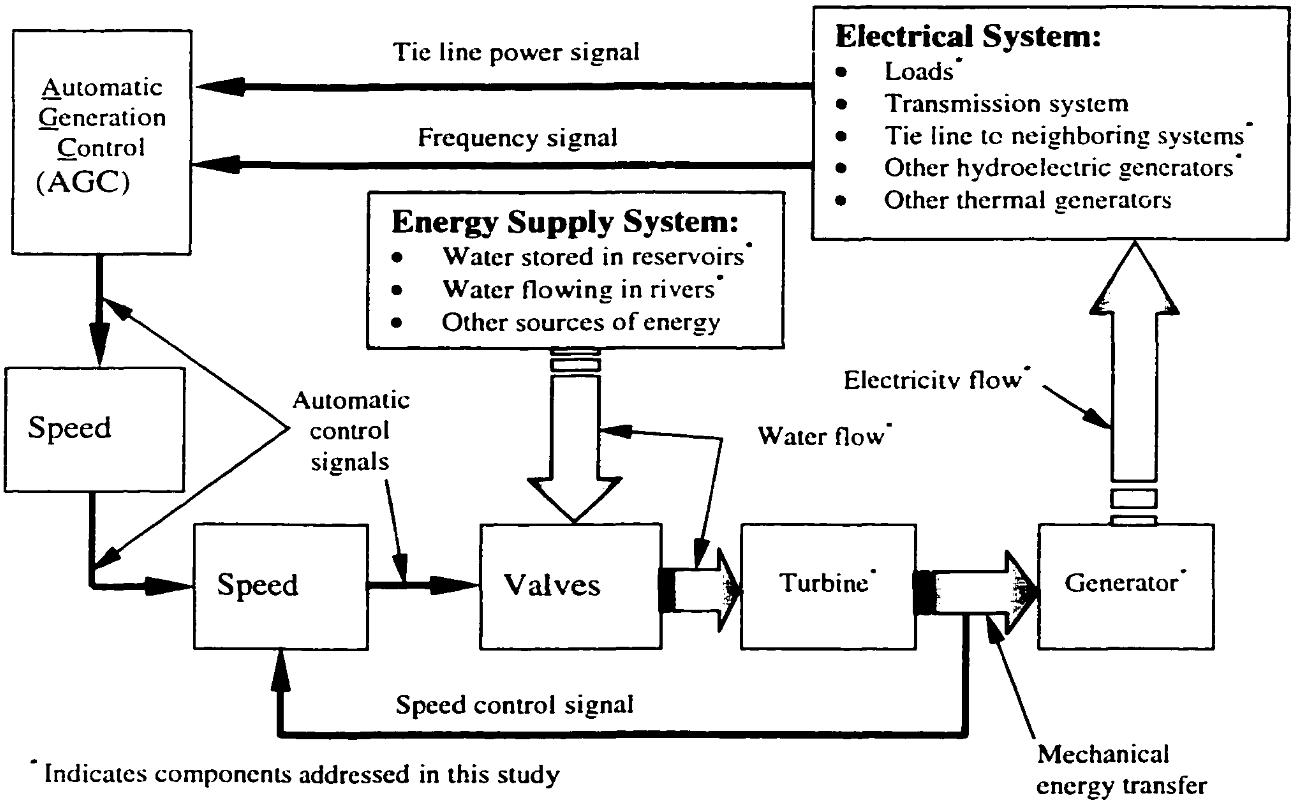


Figure 4.9. Main Components of Power Generation and Control System.

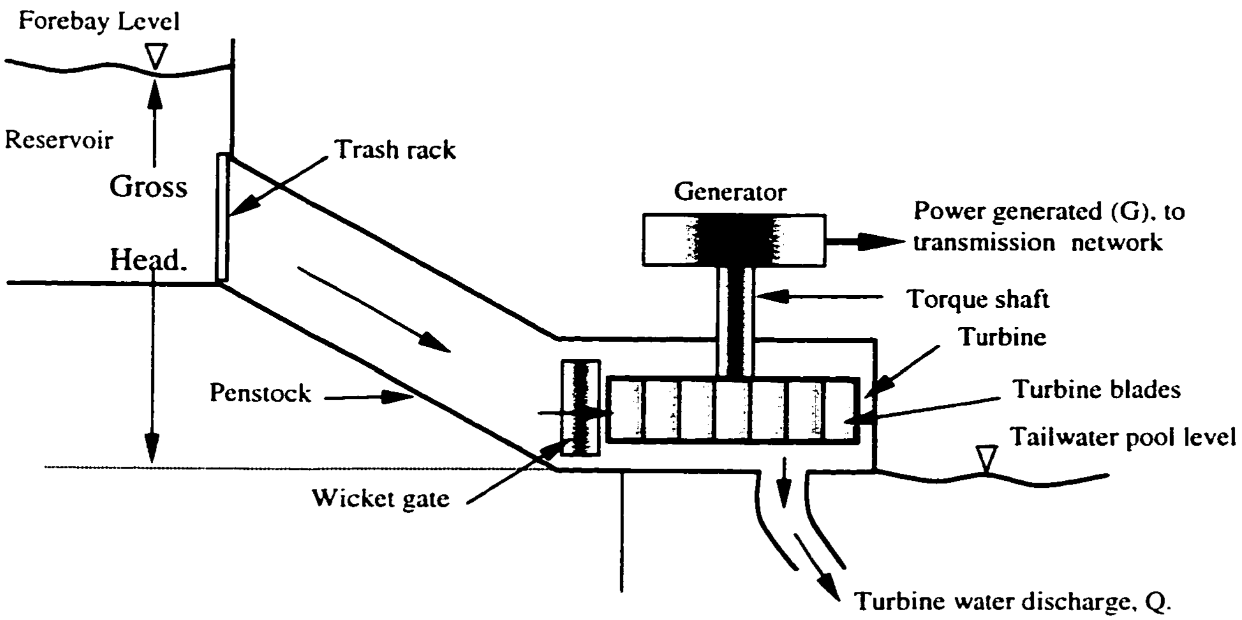


Figure 4.10. Schematic of a Hydroelectric Plant with Francis Reaction Type Turbine.

The main components of a hydroelectric generation plant are depicted in Figure 4.10. Hydraulic turbines can be generally grouped into two types: impulse turbines and reaction turbines. The impulse turbine is used for high heads – 300 meters or more, which utilize the kinetic energy of high-velocity jets of water to transform the water energy into mechanical energy. The high-velocity jets of water, derived from the pressure head, hit spoon-shaped buckets and exit the plant, in most cases, at atmospheric pressure. The spoon-shaped buckets are attached to a torque shaft, which connects the turbine with the generator. In the B.C. Hydro system, the high-head Bridge River and Wahleach hydroelectric generating plants utilize this technology.

Reaction turbines derive power from the combined action of potential (pressure head) and kinetic forms of water energy. Water pressure within reaction turbines is above atmospheric, and can be as high as 360 meters in pressure head. The illustration in Figure 4.10 depicts a typical setup of the Francis reaction type turbine, which is typical of the majority of the turbines installed in B.C. Hydro. The water from the reservoir passes through the penstock into the wicket gates, which control the amount and direct the flow of water tangentially to the turbine blades. The turbine blades direct the flow of water to exit axially into the tailwater pool.

The fundamental variables of head and turbine discharge are directly related to the power that can be generated by a hydroelectric unit. The traditional equation for determining the power capacity of hydropower units is:

$$G_{watts} = \rho g Q H \tag{4.5.2.1}$$

where G_{watts} = unit power capacity, watt

ρ = mass density of water in kg/m^3

g =acceleration of gravity, m/sec^2

Q = discharge through turbine, m^3/sec

H = effective head, m.

This equation represent the theoretical conditions, and the actual power output is negatively affected by the fact that the turbine has some losses in transforming the potential and kinetic energy into mechanical energy, and the generator also has some losses in transforming the mechanical energy into electric energy. This leads to the introduction of two efficiency terms, which are usually called the turbine efficiency term (η^T), and the generator efficiency term (η^G), to the equation:

$$G_{watts} = \rho g Q H \eta^T \eta^G \tag{4.5.2.2}$$

Sometimes the two efficiency terms are lumped into one overall efficiency term (η), and the equation becomes:

$$G_{watts} = \rho g Q H \eta \tag{4.5.2.3}$$

Substituting for the density and the acceleration of gravity, the above equation becomes:

$$G = 9.806\, QH\eta, \tag{4.5.2.4}$$

where G in measured in Kilowatts (1000 watts). This equation states that the power generated by a generator is directly proportional to the head on the turbine and to the water discharge that passes through the turbine.

ii. Modeling of Hydroelectric Generation Facilities

A hydroelectric generating facility could consist of one or more powerhouses and each powerhouse could consist of one or more generating units. Power generation of unit i in powerhouse n in plant j (G_{inj}), ($i \in I$, $n \in N$, $I \subset N \subset J$), is a function of the gross head (H_{nj}) of powerhouse n, and the turbine discharge of unit i,

$$G_{inj} = f(H_{nj}, QT_{inj})\,. \tag{4.5.2.5}$$

If net head is used then the above relationship should include trash rack, penstocks or tunnel(s), and unit's penstock head losses (Severin et. al.. 1993; Divi, 1985; Wunderlich et. al., 1985). The gross head of a powerhouse is a function of the plant's forebay and its tailwater level TWL_{nj},

$$H_{nj} = FB_j - TWL_{nj}\,. \tag{4.5.2.6}$$

The tailwater level depends on the plant's total discharge (rather than the unit's discharge) and on downstream water level $DSWL_j$, (e.g., downstream reservoir, lake, river, tide, etc.,)

$$TWL_{nj} = f(f(DSWL_j), \textstyle\sum_{i=1}^{I} \sum_{n=1}^{N} QT_{inj}, QS_j, QSF_j)\,. \tag{4.5.2.7}$$

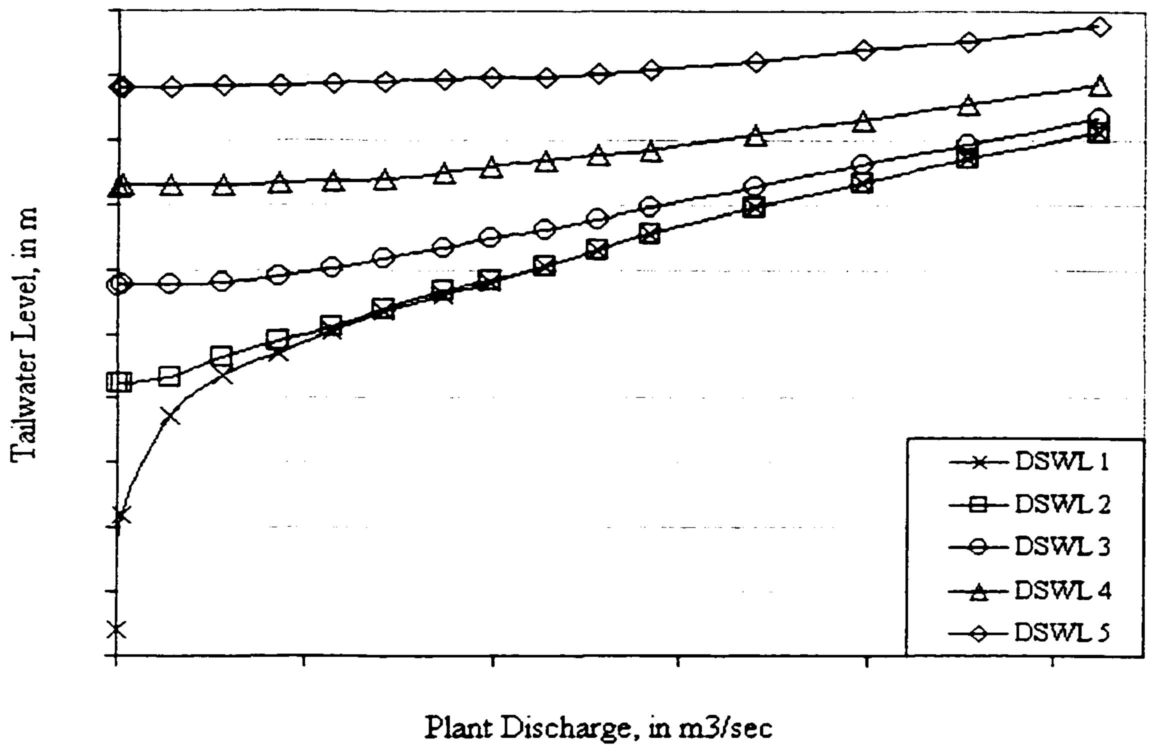


Figure 4.11. Tailwater Level vs Plant Discharge and Downstream Water Level

Figure 4.11 illustrates equation (4.5.2.7) in graphical form for a typical plant in the B.C. Hydro system, and it highlights the hydraulic coupling between serially connected hydroelectric facilities. These relationships are usually derived from either actual measured data, or from flow routing models such as the well-known, U.S. Army Corp of Engineers', HEC model. The other complicating factor is that all of the above relationships are a function of unit availability (C_j) for a given plant load.

There is an increase in modeling complexity when one tries to model, in detail, the operation of generating units in a plant that contains several powerhouses, each of which contains several units that are hydraulically coupled with other generating facilities in the same river system. For this reason an optimal unit commitment assumption was made when operating a plant for a given number of available units, forebay level, and plant loading. To derive an optimal unit commitment in a plant, a static plant unit commitment program (SPUC) (Smith, 1998) using a dynamic programming algorithm tabulated the optimal plant discharge for each increment in plant loading, forebay level, for each unit availability combination and for a downstream water level that represents normal operating conditions. The objective function of SPUC is to minimize the plant's total turbine discharge.

The assumption of optimal unit commitment and minimizing the plant's turbine discharge are valid for the purpose of all short-term planning activities and for the majority of real-time unit dispatch. The exception is when a unit in a plant is loaded in a must run condition under certain operational circumstances (e.g., fish-flush, ancillary service operations, etc).

iii. Modeling of the Production Function of Hydroelectric Generating Plants

a. General Background on the Generation Production Function

The assumption of optimal unit commitment has allowed the use of the SPUC tabulated database to generate a production function for each of the hydroelectric generating plants modeled in this study. Figure 4.12 illustrates a production function of a typical plant with multiple units in the B.C. Hydro system. Production functions are attractive because they are both simple and powerful. They are simple because they consist of only one formula or computer routine, yet they are powerful because this single expression can effectively summarize an enormous amount of detailed engineering data. For example, the production function of a hydro generating plant encompasses many details on the turbines, generators, and hydraulic structures in the plant. The production function depicted in Figure 4.12 represents the optimal transformation of the main input variables, water and forebay level, into the product, electric energy. A production function is technically efficient because each point on the production function's surface represents the maximum electric energy that can be obtained from any given sets of turbine water discharge and forebay for the number of units it represents. The production function therefore excludes any lesser amount of electric energy that would come from a wasteful or technically inefficient use of water and forebay.

The characteristics of a generating plant production function – its shape, slope, and smoothness – are important features that usually determine the kind of optimization techniques that can be usefully applied. An isoquant is a locus on the production function of

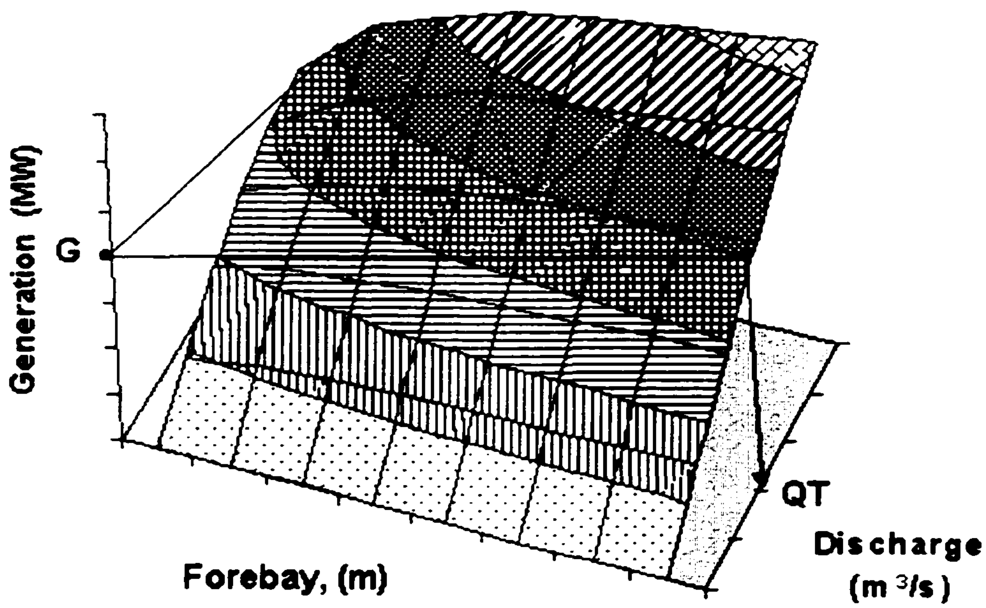


Figure 4.12. Production Function of a Hydroelectric Generating Plant.

all equal levels of electric energy production. It illustrates an important phenomenon: many different combinations of water turbine discharge and forebay inputs can result in the same level of electric energy production. As illustrated in Figure 4.12 above, they are the surface cuts at specified levels of electric energy production (e.g., the energy production "G" indicated in the Figure 4.12). For example the surface cut parallel to the forebay-discharge surface is indicative of the effect of change in forebay and discharge for a given generation level. It can be seen that as the forebay decreases, the turbine discharge (*QT*) increases. Other surface cuts provide information on other characteristics of the production function. The shape of these cut affect the optimization methods that could be used. The slope reflects the rate at which each of the inputs affects the output. Finally the smoothness of cuts reflect whether there are any irregularities in input-output relationships, which could entail discontinuities in the production function.

b. Main Features of the Hydroelectric Plant's Production Functions

Close examination and study of the hydroelectric generating plants' production functions for the B.C. Hydro system revealed that they posses several attractive optimization features (particularly for use of the linear programming technique). For illustration of these features, see Figure 4.13, which represents a production function for a plant with four units.

- First, the effect of variation in forebay on the $G = f(Q)$ function for a given plant discharge is almost linear. This can be clearly seen by referring to Figure 4.13 and examining the $G = f(Q)$ curves.
- Second, although there are some "bumps" in the $G = f(Q)$ curves (as a result of optimal unit commitment and switching between units), the curves are very smooth for each forebay level. Note that the "bumps" in the $G = f(Q)$ curves can not be readily and clearly seen in Figure 4.13, and for this reason the G/Q curves have been provided. The G/Q result from dividing the plant generation by the plant discharge to give the H/K factor, which is routinely used as a proxy for efficiency.
- Third, the $G = f(Q)$ curve for a given forebay is slightly concave, and in many instances is almost linear.
- Fourth, the peaks of the "bumps" in the G/Q curve represents local peak efficiency performance of the plant for a given plant generation range. These peaks result from operating one or a combination of units at their maximum efficiency, or optimal unit commitment.
- Fifth, the $G = f(Q)$ curves are almost linear between consistent ranges of plant discharge. This can be illustrated by taking a ruler and matching the curve for certain turbine discharge ranges.
- Sixth, the $G = f(Q)$ curves are not smooth near the plant's minimum operating ranges, which results from frequent switching between units due to the existence of inoperable generation zones for individual units. The inoperable zone results from excessive vibration, frequency problems, etc.
- Seventh, the $G = f(Q)$ are continuous except near the minimum operating ranges.

The above features have facilitated the use of a piecewise linear production function in the form of a surface with inputs being the turbine discharge, the forebay level and unit availability, and the output the plant generation. The production function for each plant consists of a family of piecewise linear curves that have been curve-fitted by a specialized procedure (as described in c. below) to accurately describe the plant generation at time-step t (G_{jt}) as a function of its forebay level, turbine discharge and unit availability,

$$G_{jt} = f(FB_{jt}, QT_{jt}, C_{jt}) . \qquad (4.5.2.8)$$

One of the most important algorithmic features of linear programming is that the simplex algorithm, and its derivatives, search the vertices that bound the solution space. Since these vertices are formed by the constraints, and since one of the constraints in the model is the piecewise linear production function (equation 4.5.2.8), then the optimal solution can always be found at one of the breakpoints of this function. As mentioned above, the fourth feature stated that the peaks of the "bumps" in the *G/Q* curve represent local peak efficiency performance of the plant for a given plant generation range, and that these peaks result from operating one or a combination of units at their maximum efficiency. The method used to exploit both of these features consists of a specialized curve fitting procedure consisting of several steps as described below, and representation of equation 4.5.2.8 by a piecewise linear surface production function.

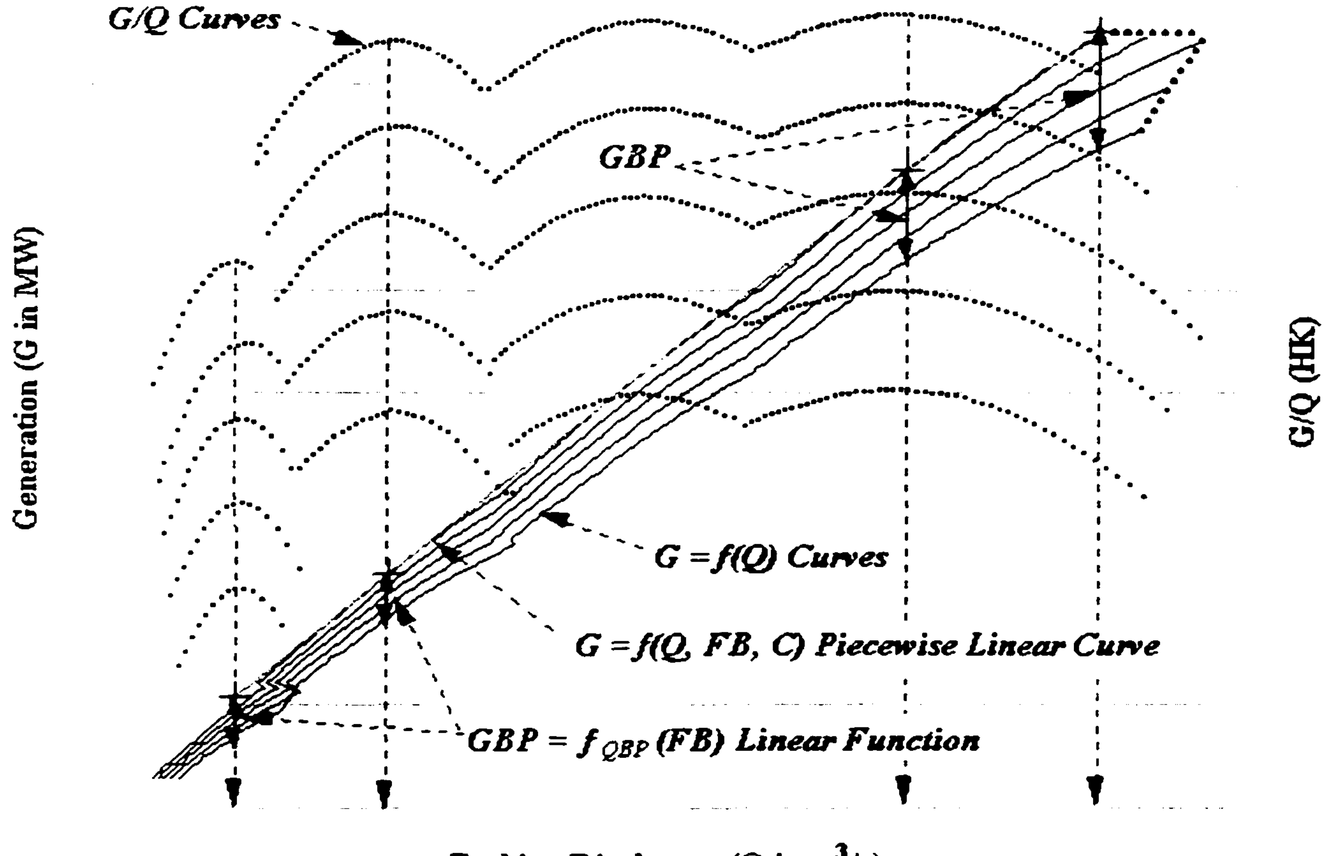


Figure 4.13. Typical Production Function for a Hydroelectric Plant with Four Units.

c. Curve Fitting Procedure for the Production Function

For each plant, the production function surface curve fitting procedure consists of the following steps:

- **Step 1.** Run SPUC for each plant. SPUC generates a database that contains for each forebay elevation and each combo (combination of the available units), the optimized plant discharge for each increment of plant generation.
- **Step 2.** For each combo and for the range of all forebay levels in a plant search for the breakpoints on the turbine discharge curve that corresponds to the peaks of the "bumps" in the *G/Q* curves. The search is done manually by plotting the SPUC output as illustrated in Figure 4.14. The search could also be automated by a combination of an optimization process coupled with a heuristic search (not done in this study). Once this search is finished, the points on the turbine discharge axis that corresponds to these peaks are located (as marked by black dots in Figure 4.14).
- **Step 3.** Decide on the number of piecewise linear segments that could accurately approximate the $G = f(Q)$ curves for each combo. After preliminary investigations, it was found that a piecewise linear curve with three segments gives a very good approximation for the majority of plants. Therefore three segments were used. The decision on using three line segments was also influenced by the additional coding that would be required in the simulator and optimizer code if the number of segments for each plant and for each combo were different. In addition, representation of piecewise linear curves in linear programming dictates generation of additional variables and constraints for each segment, and the model could become very large.
- **-Step 4.** Assuming that three segments are used, choose three peaks that could potentially represent the best fit for the piecewise linear curve with three segments. In Figure 4.14, the first three black dots on the *G/Q* curve represents such points. Choose the last point on the $G = f(Q)$ curve that corresponds to the maximum turbine discharge for all forebays. This point is marked in Figure 4.14 by the last black dot on the *G/Q* curve. Determine the intersection of the four points with the turbine discharge axis, fix and call them the turbine discharge breakpoints (*QBPs*). See Figure 4.14 for illustration.
- **Step 5.** From SPUC output, we have for each combo and forebay elevation *(FB)* the plant discharge *(Q)*, and the plant generation (*G*). To fit a piecewise linear curve the following model was used, with the QBP_1, QBP_2, QBP_3, and QBP_4 fixed: G = if ($Q \leq QBP_2$) then apply Range 1 (Q) equation, else if ($Q \leq QBP_3$) then apply Range 2(Q) equation, else apply Range 3 (Q) equation. (4.5.2.9)

  The above formula selects which equation to use in order to calculate *G*, depending on the value of Q, where,

  Range 1(Q) equation = $((\boldsymbol{a}_1(QBP_2\text{-}Q) + \boldsymbol{a}_2(Q\text{-}QBP_1))/\ (QBP_2\text{-}QBP_1))$. (4.5.2.10)

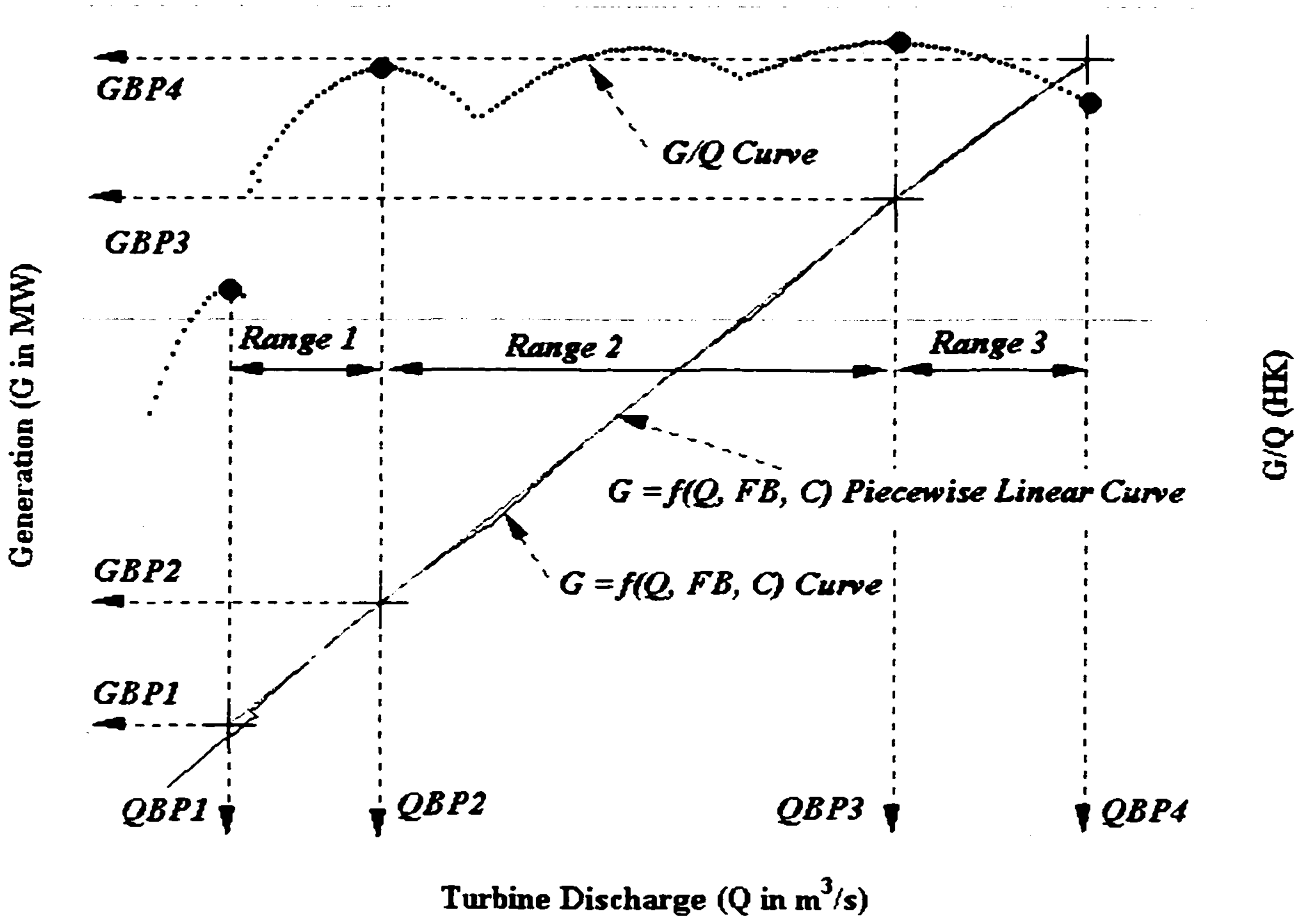


Figure 4.14. Piecewise Linear Curve Fitting Procedure of the Production Function.

Range 2(Q) equation = $((a2(QBP_3\text{-}Q) + a_3(Q\text{-}QBP_2))/(QBP_3\text{-}QBP_1))$. (4.5.2.11)

Range 3(Q) equation = $((a3(QBP_4\text{-}Q) + a_4(Q\text{-}QBP_3))/(QBP_4\text{-}QBP_3))$. (4.5.2.12)

For each forebay elevation in each Combo, the SPUC output is curve-fitted to find the coefficients: $a_1 \ldots a_4$. The above curve-fitting model was programmed in Excel Visual Basic and was solved by using the Excel Non-linear Solver (the Quasi-Newton nonlinear optimization method). The objective function in this optimization model is to minimize the sum of the absolute differences between SPUC output and the output from the formula outlined above. Constraints were required to ensure the convexity of the fitted piecewise linear curve. The convexity condition is required to enable the use of linear programming, otherwise the problem becomes a mixed integer, linear problem which requires extensive computer time and resources to solve. The constraints include the following conditions to ensure convexity of the piecewise linear curve:

$Slope_1 >= Slope_2$ (4.5.2.13)

$Slope_2 >= Slope_3$ (4.5.2.14)

where $Slope_1$ is the slope of the first linear segment,

$Slope_1 = (a_2\text{-}a_1)/(QBP_2\text{-}QBP_1)$, (4.5.2.15)

and $Slope_2$ is the slope of the second linear segment

$$Slope_2 = (a_3 - a_2)/(QBP_3 - QBP_2), \qquad (4.5.2.16)$$

and $Slope_3$ is the slope of the third linear segment

$$Slope_3 = (a_4 - a_3)/(QBP_4 - QBP_3). \qquad (4.5.2.17)$$

- **Step 6.** Once curve fitting in Step 5 is done for all forebay elevations, the *G* breakpoints ($GBP_1 \ldots GBP_4$) that correspond to ($QBP_1 \ldots QBP_4$) respectively are calculated for each forebay elevation, using the model described in Step 5 with the coefficients $a_1 \ldots a_4$.
- **Step 7.** Once the *GBPs* are calculated, a linear relationship of the forebay elevations and the *GBPs* for each *QBPs* are curve-fitted using Excel's Linear Solver. The linear curve fitting yields the coefficients (slope *m*, and constant *c*) of the straight line that represents the variation of plant generation with forebay level for each *QBPs*, as illustrated in Figure 4.13.

To calculate a plant generation given its discharge (or visa versa) for a given forebay level, the discharge range must be first determined and the corresponding equation can then be used. A linear interpolation will then be required to interpolate between the required point of interest and the two breakpoints that limit the given discharge. A similar interpolation will yield the plant discharge given the plant generation if desired. For implementation in the AMPL language and the simulator all that is needed to represent a plant's generation production function are the breakpoints of the turbine discharge (*QBPs*) and the coefficients of the linear relationship of the generation breakpoints (*GBPm's, GBPc's*) for each unit combination, as listed in Table 4.4 below.

The curve-fitting procedure outlined above produces very accurate piecewise linear curves. It yields a typical curve fitting error of about 0.30% with a maximum error of 2%. In contrast, the commonly used polynomial plant functions, yields an average error of 3.4% with a maximum error of 16.5%. Figure 4.15 illustrates the variation of error for three curve fitting procedures: piecewise linear, linear, and the polynomials.

Table 4.4. Coefficients of the Generation Production Function

Turbine Breakpoint	Generation Breakpoint (*m*) Coefficients	Generation Breakpoint (*c*) Coefficients
QBP_1	$GBPm_1$	$GBPc_1$
QBP_2	$GBPm_2$	$GBPc_2$
QBP_3	$GBPm_3$	$GBPc_3$
QBP_4	$GBPm_4$	$GBPc_4$

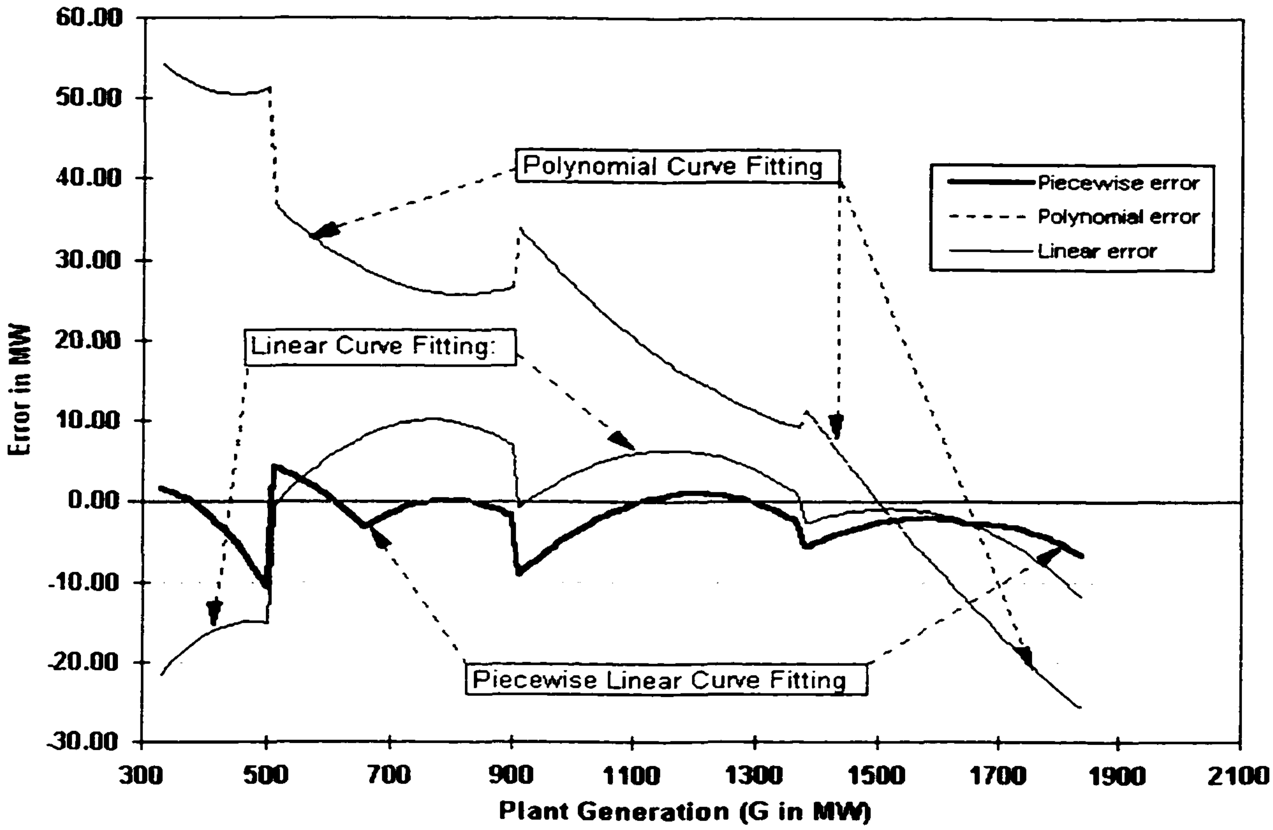


Figure 4.15. Variation of Curve Fitting Error by Three Curve Fitting Methods for a Typical Plant with Four Units.

d. Correction for Downstream Tailwater Level

SPUC assumes a constant downstream water level when calculating the optimal unit commitment. This is the most likely water level under normal operating conditions. To correct for different downstream water levels other than those assumed by SPUC, a correction to the forebay level was made to compensate for other than normal conditions. Generally, these corrections were minor. For more details, see Section 5.1. Step 4.

e. Plant Generation Limits

Generation in a plant j at time-step t is constrained by the minimum $(G^{Min}{}_{jt})$ and the maximum $(G^{Max}{}_{jt})$ physical and operational limits,

$$G^{Min}{}_{jt} \leq G_{jt} \leq G^{Max}{}_{jt} \quad (4.5.2.18)$$

To calculate the maximum generation limit, the simulator considers the following input parameters (see Annex A for details on the simulator algorithm):

- The LRB maximum generation limit (specified by the user in the LRB input data files) as outlined in Section 4.3.2;

- The maximum plant discharge, as specified by the user in the GUI (see Section 4.3.2);
- The plant spills;
- The maximum generation as calculated by the simulator as a function of the plant's forebay and unit availability (equation (4.5.2.19)) that are derived from SPUC database, as illustrated in Figure 4.16.

$$G^{Max}{}_{jt} = f(FB_{jt}, C_{jt}) . \qquad (4.5.2.19)$$

The simulator calculates the value of the maximum generation limit by taking the

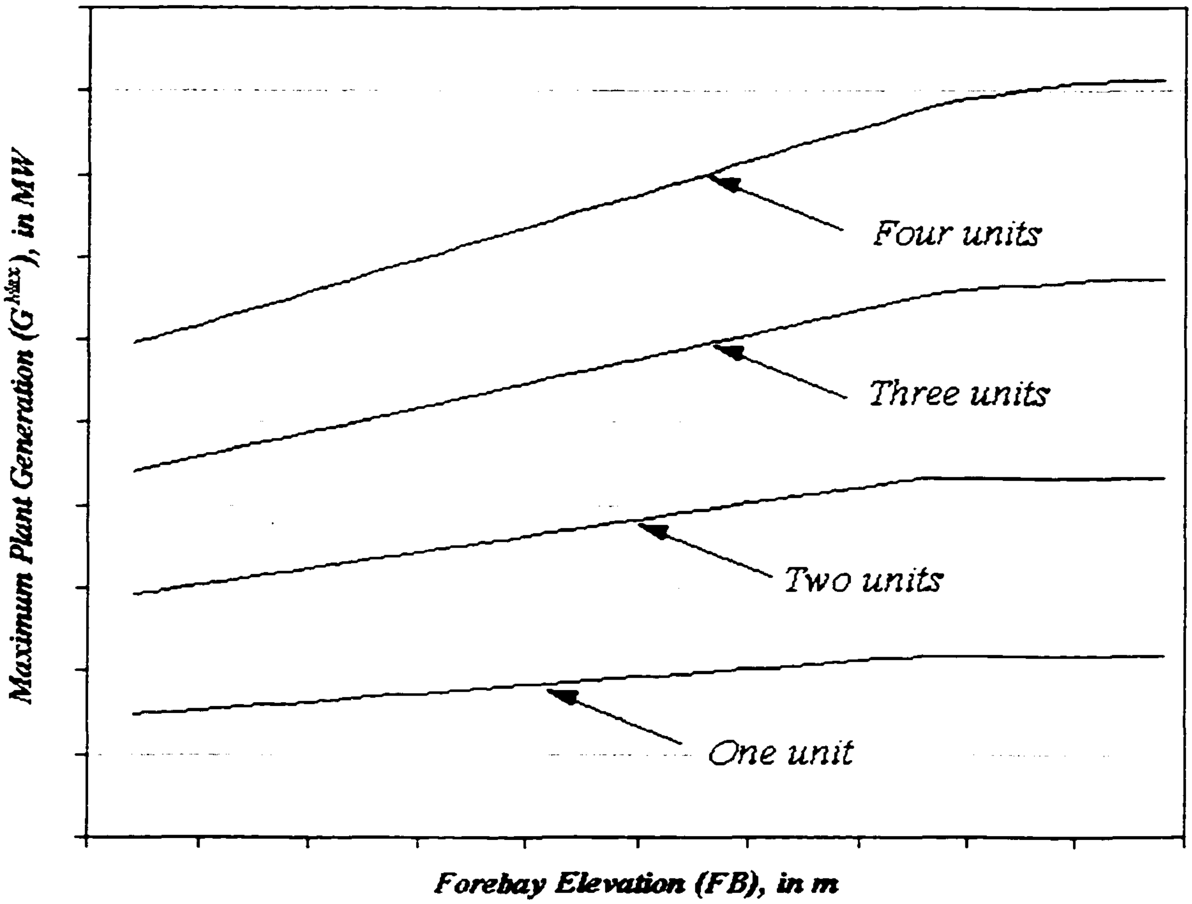


Figure 4.16. Variation of Maximum Generation Limit with Forebay Level and Unit Availability for a Typical Plant with Four Units*.

*Note that other unit combinations are omitted for presentation clarity.

minimum of the following:

- The LRB maximum generation limit;
- The calculated maximum generation limits from SPUC database; and
- The calculated maximum generation limit that corresponds to the minimum of:
  - the maximum turbine discharge limit derived from SPUC database (see Figure 4.17), and

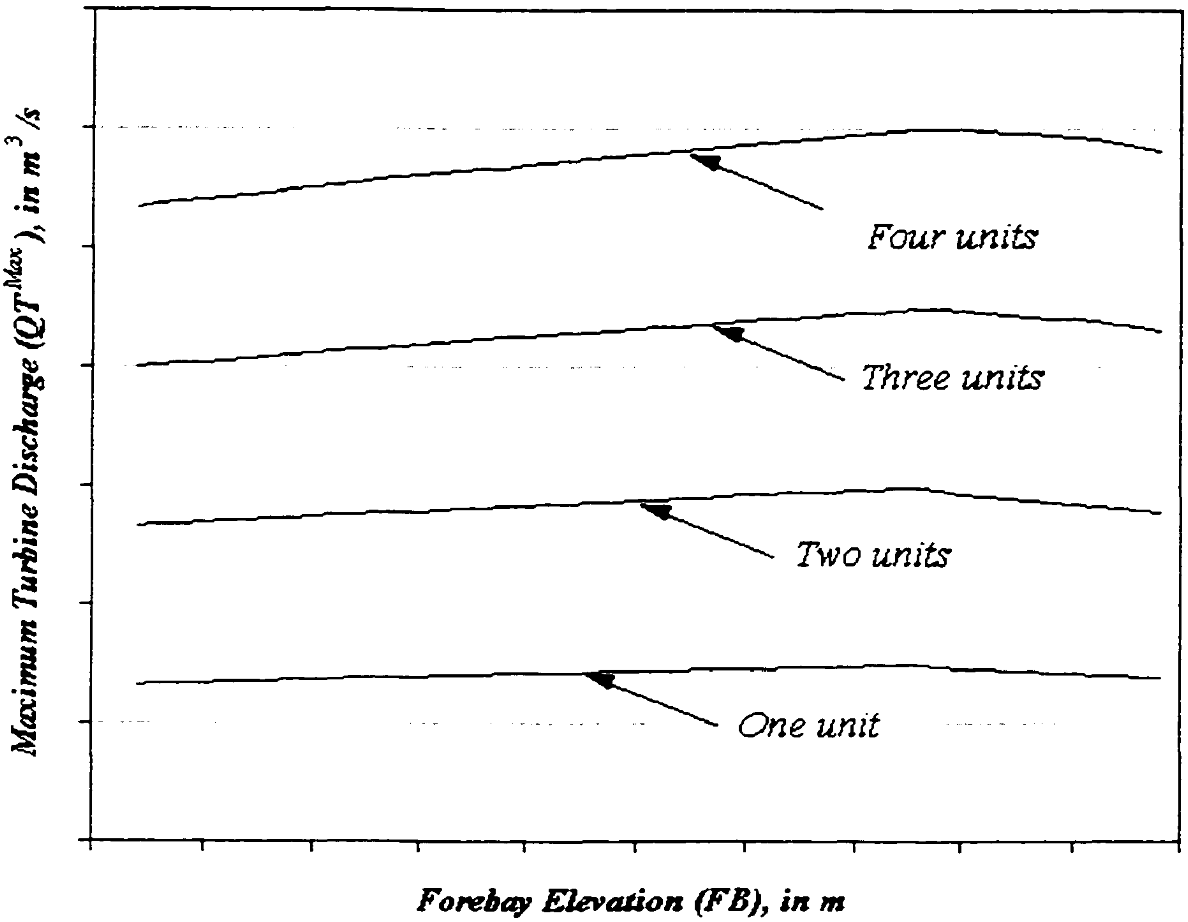


Figure 4.17. Variation of Maximum Turbine Discharge Limit with Forebay Level and Unit Availability for a Typical Plant with Four Units*

*Note that other unit combinations are omitted for presentation clarity.

- the plant turbine discharge that is calculated by subtracting the spill discharge from the maximum plant discharge specified by the user in the GUI (see Section 4.3.2).

Similarly, the minimum generation limit (G^{Min}_{jt}) is calculated by the simulator as the maximum of:

- the minimum value of all of the operable generation ranges for all available units. Typically, there are three inoperable ranges for each unit in a plant, and the simulator searches for the minimum value of all of these ranges for each unit and uses it as the minimum; and
- the calculated minimum generation limit that corresponds to the minimum plant discharge specified by the user in the GUI (see Section 4.3.2), less spills.

Once calculated by the simulator, the minimum and maximum generation limits are passed to the optimization model at each iteration in the solution algorithm (see Section 5.1).

In addition to the minimum and maximum generation limits, the GUI also allows the user to impose optional constraints that fix the LRB generation schedule ($G^{LRB}{}_{jt}$) for a plant in an optimized river system (see Section 4.3.2),

$$G_{jt} = G^{LRB}{}_{jt}\,. \tag{4.5.2.20}$$

4.5.3 Modeling of Thermal Generation

One type of thermal generation is included in the model ($GTher_t$). Thermal generation is a function of the quantity of gas used ($BTher_t$) in GJ (Giga Joules), and the thermal unit availability ($CTher_t$). It is modeled by a piecewise linear curve similar to that of the hydraulic turbines as discussed above,

$$GTher_t = f(BTher_t, CTher_t)\,. \tag{4.5.3.1}$$

The total quantity of gas (in GJ) that can be used in the study ($BTherTotal$) is fixed by a gas contract and is modeled as a hard constraint,

$$\textstyle\sum_{t=1}^{T} BTher_t = BTherTotal \tag{4.5.3.2}$$

while the total generation in the thermal plant is constrained by the maximum ($GTher^{Max}{}_t$) and minimum ($GTher^{Min}{}_t$) generation limits as follows,

$$GTher^{Min}{}_t \leq GTher_t \leq GTher^{Max}{}_t\,. \tag{4.5.3.3}$$

4.5.4 Modeling Load Resource Balance

The generating facilities are usually operated to meet the system firm demand (D_t), pre-scheduled net transactions (exports and imports) (PNS_{mt}), ($m \in M$ (U.S., AB)), and net spot sales (NSS_{mt}). When the net prescheduled transactions and net spot sales are positive, then net export occurs; otherwise, when they are negative, then net imports occurs. In a typical study, a subset of all generating plants with pre-scheduled generation ($GSim_{st}$), ($s \in S$), are simulated, and the rest are optimized. The load-resource balance equation then becomes,

$$\textstyle\sum_{j=1}^{J} G_{jt} + \sum_{s=1}^{S} GSim_{st} + GTher_t - \sum_{m=1}^{M} PNS_{mt} - \sum_{m=1}^{M} NSS_{mt} \geq D_t\,. \tag{4.5.4.1}$$

Prescheduled transactions are fixed parameters in the model that are saved from the LRB system as described in Section 4.3.1, while net spot sales are variables in the model, except where indicated otherwise.

4.5.5 Modeling Operating Reserve and Regulating Margin Requirements

In addition to electricity generation, generating facilities are also operated to meet real-time operational requirements such as spinning reserve obligations ($G^{ORO}{}_j$) and regulating margin requirement (RMR) as defined by the Western System Coordinating Council (WSCC) reliability criteria (WSCC, 1997). To meet these requirements, equation (4.5.2.18) is modified in the model as follows:

$$G^{Min}{}_{jt} \leq (G_{jt} \cdot (1 + G^{ORO}{}_j) + G^{RMR}{}_{jt}) \leq G^{Max}{}_{jt} \tag{4.5.5.1}$$

where $G^{RMR}{}_{jt}$ is a variable in the model that represents the contribution of plant j to the total regulating margin (RMR). To ensure that the regulating margin requirement is met at each time step t, the model includes the regulating margin buffer constraint as follows,

$$\textstyle\sum_{t=1}^{J} G^{RMR}{}_{jt} \geq RMR\,. \tag{4.5.5.2}$$

The *RMR* and the $G^{ORO}{}_j$ are specified by the user in the GUI as described in Section 4.3.2.

4.5.6 Modeling Import and Export Transfer Capability

Tie line maximum and minimum available transfer capability for net sales ($NSS^{Max}{}_{mt}$, $NSS^{Min}{}_{mt}$) limits the net spot sales to markets in the U.S. and Alberta as follows,

$$NSS^{Min}{}_{mt} \leq NSS_{mt} \leq NSS^{Max}{}_{mt}, \qquad (4.5.6.1)$$

The limits on net spot sales for each market are user inputs in the GUI, as described in Section 4.3.2.

4.6 STOM OPTIMIZATION MODELS

STOM provides the user with the facility to select one of four objective functions for the optimization study (see Section 4.3.2): maximize efficiency; minimize the cost of water used; maximize power production for a given storage target level; and maximize profits. For each objective function the optimization model is dynamically formulated by the decision support system using the AMPL modeling language. The optimization models are formulated in two steps. First, the variables, the set of equations, and the parameters common among the four objective functions are included in the model. Second, the additional variables, constraints and parameters specific to each objective function are then added to the model. The following subsections list the generalized optimization model common to all objective functions, and the additional variables, constraints and parameters required for each objective function. More details on dynamic formulation of the optimization models for each objective function can be found in Section 5.1.

4.6.1. The Generalized Optimization Model

Optimization models are usually divided into three basic components: the objective function; the decision variables; and the constraints. These are discussed below.

i. Decision Variables

The decision variables in the common model are of two types, independent and dependent variables. Independent variables are those that the optimization algorithm searches for, while the dependent variables are calculated by the model's equations. There are two categories of variables in the optimization problem: hydro variables, and power generation variables. The hydro variables are continuous, while the power generation variables are discrete, as follows:

- The independent turbine discharge variables, QT_{jt}, in cubic meters per second,
- The independent forced spill discharge variables, QS_{jt}, in cubic meters per second,
- The dependent total plant discharge variables, QP_{kt}, in cubic meters per second,
- The dependent reservoir storage variables, S_{kt}, in cubic meters per second for one day,
- The dependent plant generation variables, (G_{jt}), in megawatts for each hour.

In addition, there are other variables that are specific for other objective functions, as described in subsequent subsections.

ii. The Constraints

There are two different types of general constraints for this problem: hydro constraints, and power generation constraints.

The *hydro constraints*, as discussed in section 4.5.1, are:

- the piecewise function representing the forced spill discharges from a reservoir,
  $QS_{kt} = f(S_{kt})$, (4.6.1.1)
- the matrices representing the turbine discharges from a reservoir,
  $RT_{jkt} = QT_{kt} * QTR_{jk}$, (4.6.1.2)
- the matrices representing the spill discharges from a reservoir,
  $RS_{jkt} = (QS_{kt} + QSF_{kt}) * QSR_{jk}$, (4.6.1.3)
- the matrices representing the upstream turbine inflows to each reservoir,
  $UT_{jkt} = QT_{jt} * UQT_{jk}$, (4.6.1.4)
- the matrices representing the upstream spill inflows to each reservoir,
  $US_{jkt} = (QS_{kt} + QSF_{kt}) * UQS_{jk}$ (4.6.1.5)
- the upper and lower bounds on turbine discharge from each reservoir,
  $QT^{Min}{}_{kt} \le QT_{kt} \le QT^{Max}{}_{kt}$, (4.6.1.6)
- the upper and lower bounds on total spill discharges from a reservoirs,
  $QS^{Min}{}_{kt} \le (QSF_{kt} + QS_{kt}) \le QS^{Max}{}_{kt}$, (4.6.1.7)
- the total plant discharge from each reservoir,
  $QP_{kt} = QT_{kt} + QS_{kt} + QSF_{kt}$, (4.6.1.8)
- the upper and lower bounds on total plant discharge from each reservoir,
  $QP^{Min}{}_{kt} \le QP_{kt} \le QP^{Max}{}_{kt}$ (4.6.1.9)
- the mass-balance (continuity) equation for reservoirs, that couples the storage dependent decision variables across time,
  $S_{k(t+1)} = S_{kt} + (-\sum_{j=1}^{J} RT_{jkt} - \sum_{j=1}^{J} RS_{jkt} + \sum_{j=1}^{J} UT_{jkt} + \sum_{j=1}^{J} US_{jkt} + NRI_{kt}) / 24$, (4.6.1.10)
- and, the upper and lower bounds on each reservoir storage,
  $S^{Min}{}_{kt} \le S_{kt} \le S^{Max}{}_{kt}$. (4.6.1.11)

The *power generation constraints*, as discussed in Section 4.5.2, are:

- the piecewise linear generation production function that calculates plant generation as a function of reservoir forebay, turbine discharge and unit combination,
  $G_{jt} = f(FB_{jt}, QT_{jt}, C_{jt})$, (4.6.1.12)
- the upper and lower bounds on plant generation,
  $G^{Min}{}_{jt} \le G_{jt} \le G^{Max}{}_{jt}$, (4.6.1.13)
- the optional constraint that fixes the LRB generation schedules for a plant,
  $G_{jt} = G^{LRB}{}_{jt}$. (4.6.1.14)

In addition there are other constraints that are specific for each objective function, as described in subsequent subsections.

4.6.2 Maximize the Efficiency Optimization Model

i. Objective Function

This objective function uses the hydraulic value, *H/K*, to weigh the turbine and the spill discharges for each plant, which when aggregated over the study duration results in minimizing the total energy used by the optimized plants. This objective function is typically used when the user would like to maximize the efficiency of the optimized plants in the process of preparing preliminary hourly planning schedules for several days ahead (up to one week). The H/K values are used as a proxy for the plant's efficiency, and they are calculated by dividing the plant's generation by the turbine discharge for the third point of the piecewise linear generation production function. This point usually represents the range with the most efficient production level near the maximum capacity of plants. The optimization algorithm calculates the H/K values internally and corrects for head variations in each run. The objective function is expressed in the model as,

$$Minimize:\ \sum_{j=1}^{J} \sum_{t=1}^{T} (QT_{jt} + QS_{jt} + QSF_{jt}) * HK_j . \qquad (4.6.2.1)$$

ii. Additional Decision Variables

There are no additional decision variables for this objective function.

iii. Additional Constraints

In addition to equations in the generalized model (4.6.1.1-4.6.1.13), the only additional constraint for this objective function is the hydro-generation coupling equation representing the load-resource balance, as discussed in section 4.5.4. Note that thermal generation ($Gther_t$) as well as the net spot sales (NSS_{mt}) are fixed at their LRB values. The load-resource balance equation is expressed in the model as,

$$\sum_{j=1}^{J} G_{jt} + \sum_{s=1}^{S} GSim_{st} + GTher_t - \sum_{m=1}^{M} NSS_{lmt} - \sum_{m=1}^{M} PNS_{mt} \geq D_t \qquad (4.6.2.2)$$

4.6.3. Minimize the Cost of Water Used Optimization Model

i. Objective Function

This objective function uses the Cost Factor, *CF*, to weigh the turbine and the spill discharges for each plant, which when aggregated over the study duration result in minimizing the total cost of water used by the optimized plants. *CF* is a user input parameter for each plant, and it reflects the cost of water to be used for power generation and spills from each plant. A high CF corresponds to more costly (valuable) water from the corresponding plant. This objective function is typically used when the user prefers to have more control on the amount of water used from each plant, particularly from the upper-most reservoirs in each river system (e.g. the Kinbasket in the Columbia, or the Williston in the Peace). It could be used in the process of preparing preliminary hourly planning schedules for several days ahead (up to one week) that could reflect the "Generation Schedule Preference Order" for the planning period. If the user wishes to use more water from a particular plant, then a lower CF relative value could be assigned to that plant. The default CF values are calculated in the GUI by dividing 1.0 by the number of plants selected for optimization. Although it is a good practice to normalize the CF values to add up to 1.0, it is, however, not a requirement. If the user has access to the marginal value of water for each plant (in $/m^3/s) in the optimization study, these values can be entered, and the optimization study will then minimize the total value of the plants' discharges used to meet the load and to meet spills requirements. The objective function is expressed in the model as,

$$\text{Minimize: } \sum_{j=1}^{J} \sum_{t=1}^{T} (QT_{jt} + QS_{jt} + QSF_{jt}) * CF_j . \qquad (4.6.3.1)$$

ii. Additional Decision Variables

There are no additional decision variables for this objective function.

iii. Additional Constraints

In addition to equations in the generalized model (4.6.1.1-4.6.1.13), the only additional constraint for this objective function is the hydro-generation coupling equation representing the load-resource balance, as discussed in section 4.5.4. Note that thermal generation ($Gther_t$) as well as the net spot sales (NSS_{mt}) are fixed at their LRB values. The load-resource balance equation is expressed in the model as,

$$\sum_{j=1}^{J} G_{jt} + \sum_{s=1}^{S} GSim_{st} + GTher_t - \sum_{m=1}^{M} NSS_{lmt} - \sum_{m=1}^{M} PNS_{mt} \geq D_t \qquad (4.6.3.2)$$

4.6.4 Maximize the Value of Power Production Optimization Model

i. Objective Function

This objective function maximizes the value of the additional power that could be generated in the study, provided that target reservoir levels at the end of the study are met. The target reservoir levels are determined by simulating forebay levels, for each plant, given the LRB generation schedule, reservoir's spills and inflows. In this objective function, the optimized spot sale schedules ($SpotPower_t$) are weighted by user-input hourly spot prices that reflect estimates of the prevailing market conditions over the study duration. The user in the GUI could shape the hourly spot price structure to reflect peak-, high-, and low-load hour prices. This objective function is typically used when the user would like to maximize the short-term revenues from spot sales in the process of preparing preliminary hourly planning schedules for several days ahead (up to one week). The objective function is expressed in the model as,

$$\text{Maximize: } \sum_{t=1}^{T} SpotPower_t * SpotPrice_t \qquad (4.6.4.1)$$

ii. Additional Decision Variables

There is one additional independent variable in this objective function, and it represents the additional hourly spot power ($SpotPower_t$) that could be generated and possibly sold in the spot market given the fixed reservoir's target levels.

iii. Additional Constraints

In addition to the equations in the generalized model (4.6.1.1-4.6.1.13), two additional constraints are added. The first, fixes the storage level for each optimized reservoirs to the (LRB) scheduled storage at the last time step in the study,

$$S_{kT} = S^{LRB}_{kT}. \tag{4.6.4.2}$$

The second constraint is the hydro-generation coupling equation representing the load-resource balance, as discussed in section 4.5.4. Note that thermal generation ($Gther_t$) as well as the net spot sales (NSS_{mt}) are fixed at their LRB values, and the new variable $SpotPower_t$ is added to the equation. The load-resource balance equation is expressed in the model as,

$$\sum_{j=1}^{J} G_{jt} + \sum_{s=1}^{S} GSim_{st} + GTher_t - \sum_{m=1}^{M} NSS_{lmt} - \sum_{m=1}^{M} PNS_{mt} - SpotPower_t \geq D_t \tag{4.6.4.3}$$

4.6.5 *Maximize the Profit Optimization Model*

i. Objective Function

For a hydroelectric system with significant multi-year storage, the prime objective is to first meet the domestic load demand and firm export/import contracts and then to make the optimal trade-off between present benefits, expressed as revenues from real-time spot energy sales, and the potential expected long-term value of resources, expressed as the marginal value of water stored in reservoirs. In other words, the decision to be made is when and how much to import and/or export and how much thermal energy to generate as well as when, where and how much water to store in or draft from reservoirs while meeting the domestic load and the firm export/import contracts. This objective function is intended for use in the Shift Office in real-time operations mode. The objective is expressed in the model as,

Maximize:

$$\begin{aligned} &+\sum_{m=1}^{M} \sum_{t=1}^{T} NSS_{mt} * NSSPrice_{mt} \\ &+\sum_{k=1}^{K} (S_{kT} - STarget_{kT}) * MVW_k * 24 * 3600 \\ &-\sum_{t=1}^{T} GThert * TIC_t \end{aligned} \tag{4.6.5.1}$$

The first term represents the sum of revenues (or costs) accrued from net spot energy

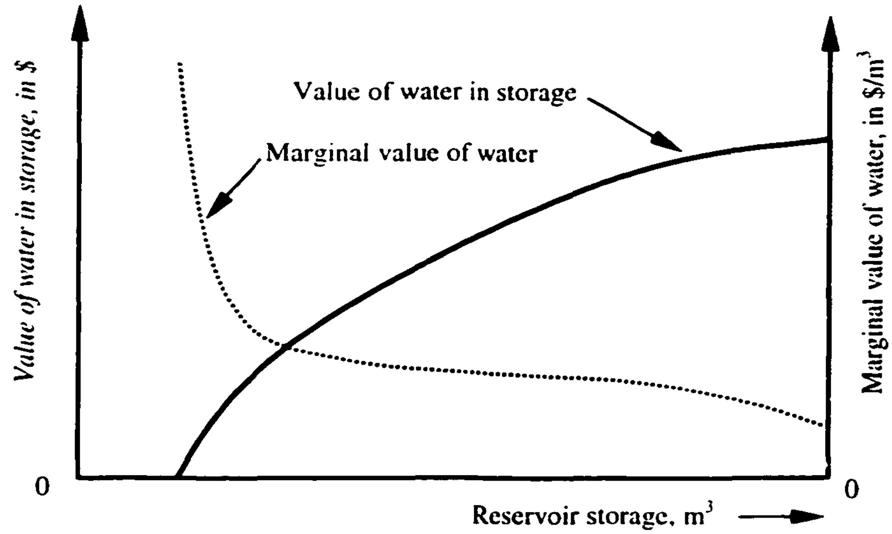


Figure 4.18. Value of Water in Storage and Marginal Value of Water for Time Step *t*

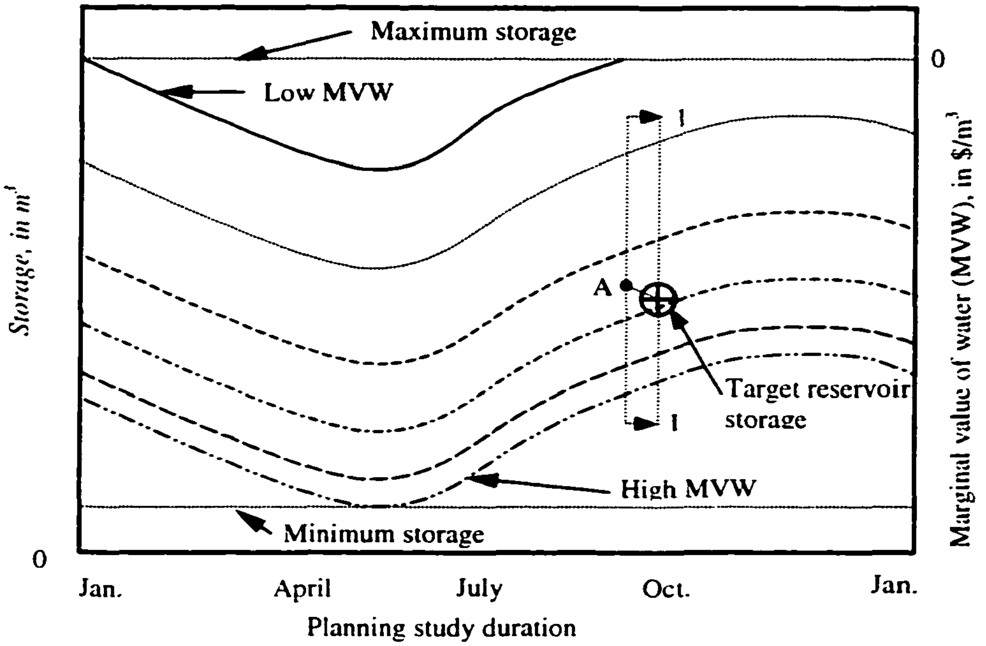


Figure 4.19. Marginal Value of Water as a Function of Storage and Time

exports (or imports), given forecast hourly spot prices ($NSSPrice_{mt}$) in $/MWHr, in the U.S. and Alberta electricity markets. The second term represents the sum of storage cost (or added storage value) of deviating from the terminal target storage level ($STarget_{kT}$) at target hour (T). For each optimized reservoir, multiplying the difference between the optimized storage at the target hour (S_{kT}) and the target storage ($STarget_{kT}$) by the marginal value of water (MVW_k), in $/m^3, yields its storage cost (or added storage value). The MVW_k and the $STarget_{kT}$ are calculated in the model from the $Rbch_j$ (Rate for B.C. Hydro) and the target forebay levels respectively. The user specifies $Rbch_j$ and the target forebay level in the GUI, as described in Section 4.3.2. The third term accounts for the cost of thermal generation, and is calculated by multiplying the optimized thermal generation by the thermal energy input cost (TIC_t) in $/MWHr, which is calculated from a user-input in the LRB system on the cost of the gas contract.

The marginal value of water and the target storage for each reservoir are predetermined from long and medium term optimization studies, which yield a water value function, as described in Section 3.2.4. Stochastic dynamic-programming and other models establish the value of water stored in reservoirs as a function of storage levels and the study duration, as illustrated in Figure 4.18. The derivative of the value of water function yields the marginal value of water for the duration of the planning horizon and for each storage state, a shown in Figure 4.19.

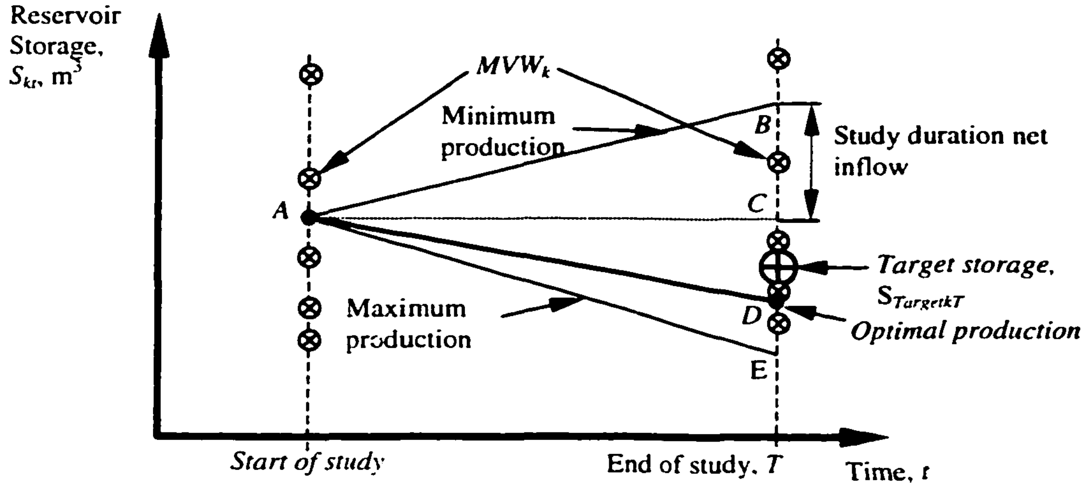


Figure 4.20. Cut of the Water Value Function.

For use in real-time operations mode, a cut of these curves (section 1-1 shown in Figure 4.19) for the study duration provides information on the value of water for the next decision time frame. As shown in Figure 4.20, at the start of the study, reservoir storage is at point A. During the study, the storage changes to point B, if generation was at its minimum allowable production level, with the net increase in storage being the difference between points B and C. Depending on the prevailing electricity market conditions and the marginal value of water (MVW_k), production from a hydroelectric facility can cause the reservoir to end anywhere between points B and E. If the assumptions used in the long and medium-term planning models (market, inflow and modeling detail assumptions) were reasonably accurate, then the optimal production and target reservoir storage levels could coincide. However, if the assumptions were slightly off-the-mark, then a slight deviation from the reservoir's target storage level could occur. With very high market prices production is maximized, and the reservoir's storage could be drawn-down to point E. If the value of the spot trading sales slightly exceeds the value of deviation from the target storage level, then storage would drop to point D. Thus, depending on the MVW_k and market prices, the optimization model determines the optimal tradeoff between the present benefits and the expected long-term value of resources.

This optimization process is equivalent to finding the point of intersection between the resource value function and the market demand function for resources selected for optimization (hydro, thermal and spot sales). If the intersection point corresponding to a production level higher than the firm demand and the firm export/import contracts, then production surplus (in excess of the firm load demand and exports) could be offered for sale in the spot market, as illustrated in Figure 4.21. Otherwise, if the optimal production level falls short of firm load demand and the firm export/import contracts, it becomes necessary to buy power from the spot market. Thus the points of intersection between the water value function and the market demand function determine the optimal production level and the amount of spot trade sales. The resource value function does not increase at a constant rate, mainly due to the decline in water and gas use efficiency at higher production levels.

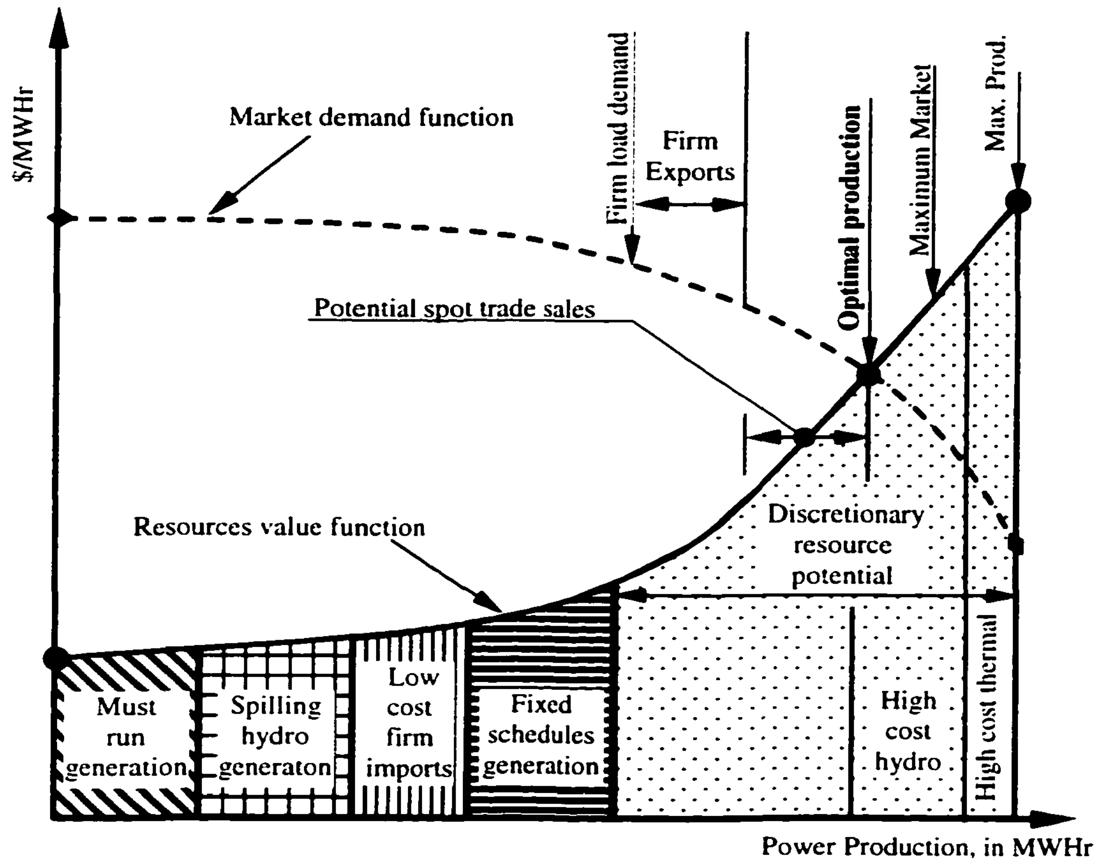


Figure 4.21. Determination of Optimal Production Level Using the Resource Value Function and the Market Demand Function

The current implementation of STOM assumes that the market demand function for B.C. Hydro is limited by the transfer capability of the tie lines that link B.C. Hydro's transmission system to markets in Alberta and the U.S., and by the maximum production level, as shown in Figure 4.21. PowerEx provides hourly forecast spot prices that represent the average prices in the Alberta and U.S. electricity markets, and also provides the hourly limits on the tie line capacities to Alberta and the U.S. Future implementation of STOM plans to include the hourly demand curve for both markets once this information becomes available.

It should be noted that the hourly shadow price (dual variable) of the load resource balance equation in this objective function provides what is known in the industry as the market-clearing price for B.C. Hydro resources. Further discussion on sensitivity analysis can be found in Chapter 6.

The above discussion on this objective function introduced two concepts: the concept of implied marginal value of water, and the concept of proximal analysis for profit maximization, as discussed further in Chapter 7.

ii. Additional Decision Variables

There are several additional independent variables in this objective function:

- The independent thermal generation variables ($Gther_t$, $Bther_t$) that represent generation of the Burrard thermal generating station as discussed in Section 4.5.3,
- The independent net spot sales (NSS_{mt}) in the U.S. and the Alberta electricity spot markets as discussed in Section 4.5.4, and
- The regulating margin requirement for each plant, G^{RMR}_{jt}, as discussed in Section 4.5.5.

iii. Additional Constraints

In addition to equations in the generalized model (4.6.1.1-4.6.1.14), several additional constraints are added to the generalized model. The first, is the load-resource balance equation that is expressed in the model as,

$$\sum_{j=1}^{J} G_{jt} + \sum_{s=1}^{S} GSim_{st} + GTher_t - \sum_{m=1}^{M} NSS_{mt} - \sum_{m=1}^{M} PNS_{mt} \geq D_t . \quad (4.6.5.2)$$

The second, represents the thermal generation from the Burrard station as discussed in Section 4.5.3, and expressed in the model by a piecewise linear curve as follows,

$$GTher_t = f(BTher_t, CTher_t) . \quad (4.6.5.3)$$

The third represents the total quantity of gas that can be used (in GJ), which is fixed by a gas contract as discussed in Section 4.5.3, and is modeled as a hard constraint,

$$\sum_{t=1}^{T} BTher_t = BTherTotal . \quad (4.6.5.4)$$

The fourth represents the bounds on the total thermal generation as follows,

$$GTher^{Min}_t \leq GTher_t \leq GTher^{Max}_t . \quad (4.6.5.5)$$

The fifth, replaces equation 4.6.1.13 to represent the real-time operational requirements such as spinning reserve obligations and the regulating margin requirement

$$G^{Min}_{jt} \leq (G_{jt} \cdot (1 + G^{ORO}_t) + G^{RMR}_{jt}) \leq G^{Max}_{jt} . \quad (4.6.5.6)$$

The sixth, ensures that the sum of the regulating margin requirement for all optimized plants is met at each time step in the model, and is represented in the model as,

$$\sum_{i=1}^{J} G^{RMR}_{jt} \geq RMR . \quad (4.6.5.7)$$

The seventh, limits the net spot sales to the maximum and minimum tie line available transfer capability to markets in the U.S. and Alberta as discussed in Section 4.5.6, and is represented in the model as,

$$NSS^{Min}_{mt} \leq NSS_{mt} \leq NSS^{Max}_{mt} . \quad (4.6.5.8)$$

The eighth, is optional, and it fixes the storage level for the optimized reservoirs to the (LRB) scheduled storage at the last time step in the study,

$$S_{jT} = S^{LRB}_{jT} . \quad (4.6.5.9)$$

CHAPTER 5

THE SOLUTION AND IMPLEMENTATION PROCESS

In this Chapter the solution process adopted to solve the optimization problem is described. This is followed by a description of the implementation process adopted to develop and implement the decision support system in production mode at B.C. Hydro.

5.1. THE SOLUTION PROCESS

The main concern of this section is to describe the solution process that has been implemented to solve the mathematical programming problem presented in Section 4.5. It mainly concerns the application of the linear programming technique to solve the hydroelectric scheduling problem.

5.1.1 STOM Generalized Solution Process

The overall process used for implementation of STOM in production mode consists of several steps as shown in Figure 5.1. Many of the steps in the process have been discussed in some detail elsewhere in this study, and are referred to appropriately.

The first step in the process is to balance the LRB system, check and save the required operational input data needed to run STOM. This is discussed in Section 4.3.1. The second step involve setting the user's specifications for the simulation/optimization study using the GUI, as described in Section 4.3.2. The third step is to launch the study and transfer data from the client's workstation to the NT Server workstation. This is described in Section 4.3.3. The fourth step involves launching the AMPL session, running the simulator, formulating the optimization model and running the simulation/optimization process at the NT Server. This will be described in Section 5.1.5. The fifth step terminates the process at the NT Server, transfers output data to the client's workstation and displays the results to the user as described in Sections 4.3.3 and 4.3.6. The sixth step involves either accepting the results and terminating the overall process, or rerunning the simulation/optimization study after changing some of the input data, objective, or operational limits using the GUI, as described in Section 4.3.2.

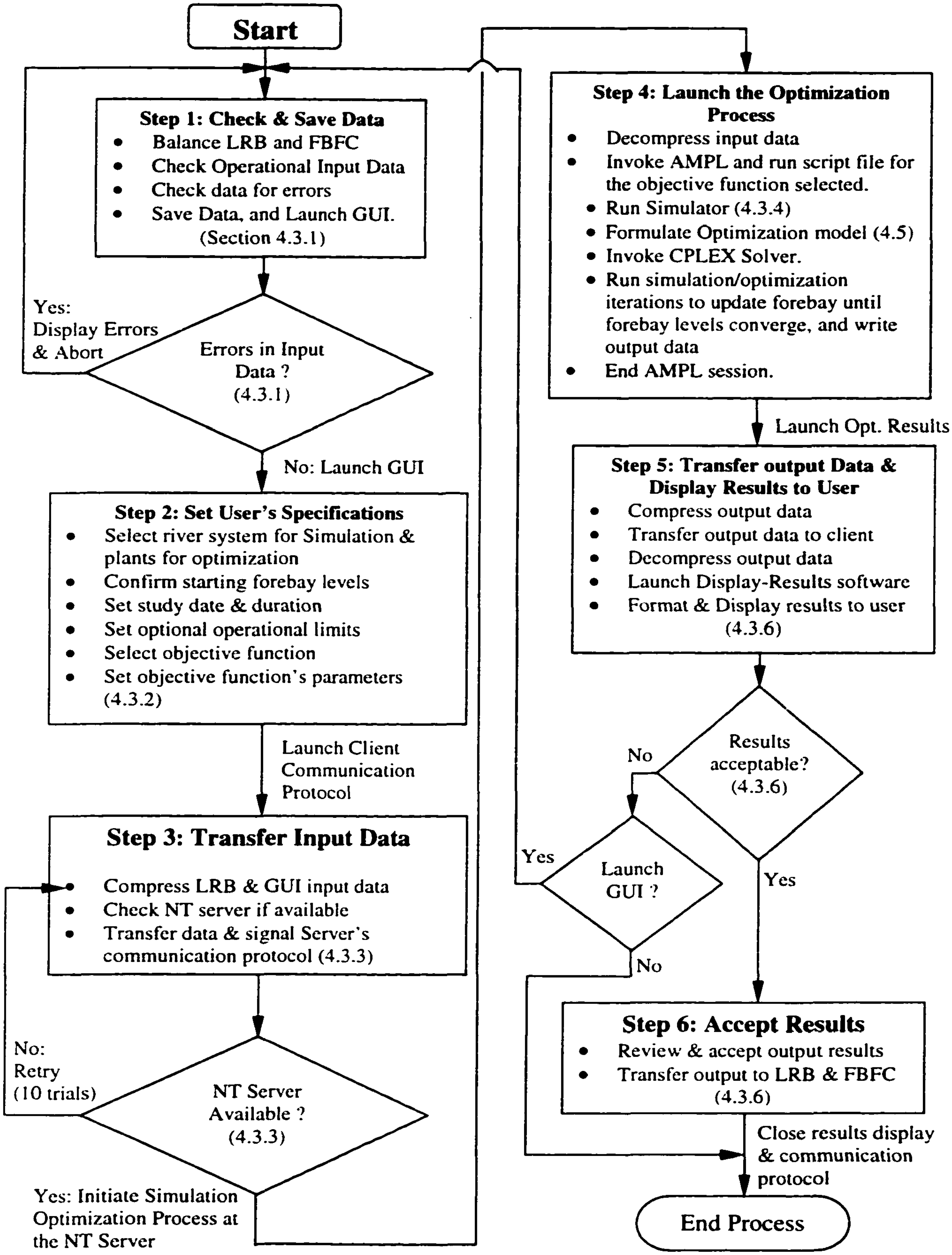


Figure 5.1. STOM Generalized Solution Process.

5.1.2 Steps of the Solution Algorithm

The solution algorithm is activated in Step 4 of STOM's generalized solution process, described in Section 5.1.1. It consists of several steps. First, the optimization process is activated by the server side communication protocol. Once the server side protocol receives the signal from the client's side communication protocol, it automatically transfers and decompresses the input data to the designated directory structure and hands over control of the optimization process by running a script text file in the AMPL syntax. The script file relates to the specific objective function chosen by the user in the GUI data-input session, and it controls the overall optimization process. Second, the system status is determined by performing a simulation run that calculates the physical and operational limits imposed by the user, determines the piecewise linear coefficients of the generation production function, and formats the input data for the optimization model. Third, the optimization model is formulated using the AMPL modeling language, and CPLEX's Primal solver is invoked to solve the problem. Fourth, a database search procedure is invoked in AMPL to determine the optimal combo numbers, given the optimized generation schedule, forebay levels, and unit availability for each hour and each plant. The simulation is then re-run to calculate the optimized forebay levels given the optimized generation schedules and optimal combo numbers. The optimal combo numbers and the optimized forebay levels are used to update the coefficients of the generation production function, while only the optimized forebay levels are used to update the generation and turbine discharge limits. A number of simulation/optimization iterations are performed (typically 3-6) until the reservoir forebay levels stabilize and converge to a given tolerance. The CPLEX fast Barrier Solver is used for these iterations, and the starting guesses are automatically updated for faster solution time. Fifth, the optimization problem is formulated for and solved by CPLEX's Primal (or Dual) algorithm (depending on the objective function), and the final solution results and sensitivity analysis information are written to text output files. The simulation and optimization output files are then transferred to the client workstation and displayed to the user by the Results-Display software. The above steps are described below and are summarized in the flow chart shown in Figure 5.2.

Step 1: Launch the Optimization Process

The server side communication protocol runs continuously on the NT Server workstation and is ready to take any client's requests. Once it receives the signal from the client side communication protocol it issues two instructions. The first instruction is used to decompress the client's input data and distribute it into a pre-assigned input data directory structure at the server. The second instruction passes a DOS argument that launches the AMPL session and invokes a script run file that specifies the objective function selected by the user. The server protocol then waits for the optimization run to terminate, when the AMPL session ends.

B.C. Hydro currently holds a one-user license for AMPL and CPLEX. For this reason, if more than one client attempts to simultaneously access the NT Server, a signal is sent to the client protocol to indicate that the server side is busy performing an optimization run or is unavailable, if the server has been taken out of service. The client protocol tries to reestablish

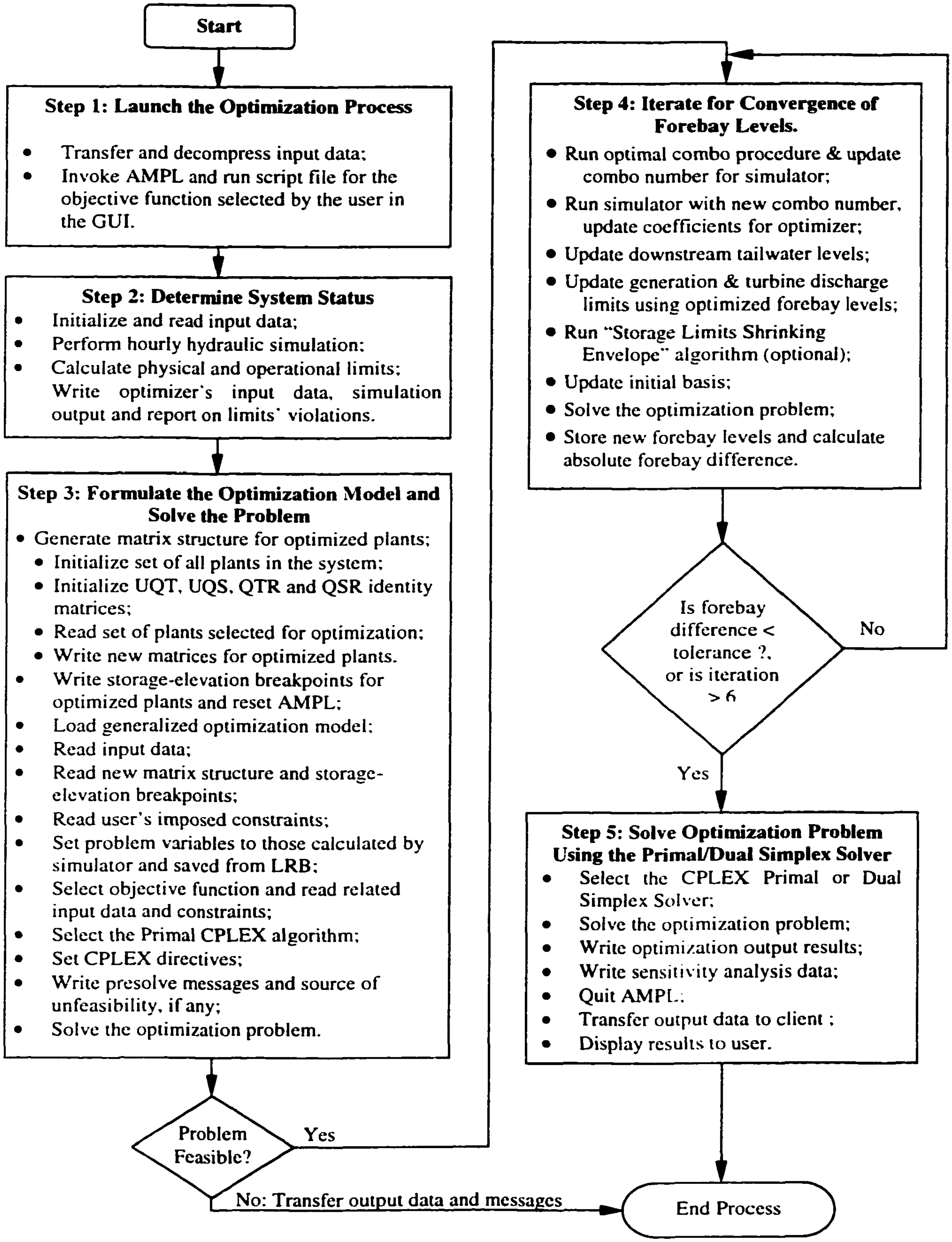


Figure 5.2. STOM's Solution Algorithm

a connection with the NT Server for up to ten times with five seconds intervals between each attempt. If the server is still busy, it then quits, and informs the user that the server is not available. The communication process log is saved to a text data file that can be accessed for debugging purposes.

Step 2. Determine the System Status

The system status is determined by running the simulator software (see Section 4.3.4) to perform the following main functions:

- Initialize variables and read input data;
- Convert initial forebay levels to storage using a table lookup that relates storage to forebay water levels;
- For each hour in the study, and for each plant selected for simulation, convert plant generation to turbine discharge using the coefficients of the piecewise linear curve (see Section 4.5 for details) as a function of forebay level and unit availability (combo number).
- Calculate non-turbine releases (gated and overflow spill releases);
- Calculate total reservoir's inflows and outflows;
- Calculate storage using the mass balance equation, and convert storage to forebay levels;
- Calculate minimum and maximum plant generation and discharge limits;
- Convert forebay limits to storage limits for use by the optimizer;
- Calculate residual generation from all non-optimized plants;
- Check and write a report on forebay, generation and discharge limit's violations;
- Write simulation results to text output file;
- Write the following optimizer's input data in AMPL format:
  - Initial time step, number of hours in the study, set of optimized plants and river systems, and initial forebay levels;
  - System load, residual generation, exports and imports;
  - For each hour in the study and for each optimized plant write:
    - Maximum and minimum generation limits;
    - Maximum and minimum plant discharge limits;
    - Maximum and minimum reservoir storage limits;
    - Scheduled generation and the corresponding turbine discharges;
    - Spill releases;
    - Local reservoir inflows;
    - Unit availability (combo number);
    - Coefficients of piecewise linear curves (see Table 4.4).

The simulator run time varies with the number of plants and the number of hours in the study. For 19 plants and 168 hours, the simulator takes about 25 seconds, while for four plants and 24 hours it takes about 3 seconds.

Step 3. Formulate the Optimization Model and Solve the Problem

In this step, the optimization model is formulated using the AMPL modeling language, and the CPLEX Primal Solver is invoked to solve the problem. The following procedure formulates the optimization model.

1. The default matrices (equations 4.5.1.1-4.5.1.4) that describe flow sources and destinations for the set of all plants in the B.C. Hydro system are loaded in AMPL. Then the set of plants selected for optimization are loaded, and the structure of UQT_{jk}, UQS_{jk}, QTR_{jk} and QSR_{jk} are determined by the intersection of the set of all plants in the B.C. Hydro system and the plants selected for optimization. The matrices resulting from the intersection are then saved to a text file in AMPL format.
2. The input data that describe the storage-elevation piecewise linear curves are written to a text file in AMPL format, and the AMPL session is reset.
3. The generalized optimization model (equations 4.6.1.1-4.6.1.13) is loaded into memory from a predetermined text file in AMPL format.
4. The input data generated by the simulator, the new matrix structure and the storage-elevation data are loaded into memory.
5. The user's imposed constraints, formulated in the AMPL modeling language syntax by the GUI, are added to or dropped from the model.
6. The objective function is selected and its corresponding input data and additional variables and constraints are loaded into memory as follows:

- If "*Maximize Efficiency*" objective function is selected, then:
  - add the objective function (equation 4.6.2.1),
  - add the load-resource balance equation (4.6.2.2),
  - if generation in a plant is fixed:
    - drop the turbine discharge limits (equation 4.6.1.6) for the fixed plant,
    - drop the total plant discharge limits (equation 4.6.1.9) for the fixed plant,
    - drop the generation limits (equation 4.6.1.13) for the fixed plant,
    - add the constraint that fixes generation to the LRB schedule (equation 4.6.1.14) for the fixed plant.
- If "*Minimize the Value of Water Used*" objective function is selected, then
  - add the objective function (equation 4.6.3.1).
  - add the load-resource balance equation (4.6.3.2),
  - read the objective function cost factor coefficients CF_j from a text file in AMPL syntax that was generated by the GUI,
  - if generation in a plant is fixed:
    - drop the turbine discharge limits (equation 4.6.1.6) for the fixed plant.
    - drop the total plant discharge limits (equation 4.6.1.9) for the fixed plant,
    - drop the generation limits (equation 4.6.1.13) for the fixed plant,
    - add the constraint that fixes generation to the LRB schedule (equation 4.6.1.14) for the fixed plant.
- If "*Maximize the Value of Power Production*" objective function is selected, then
  - add the objective function (equation 4.6.4.1),
  - add the constraint that fixes optimized storage at the last time step (equation 4.6.4.2),
  - add the load-resource balance equation (4.6.4.3),

- read the objective function coefficients $SpotPrice_t$ from a text file in AMPL syntax, generated by the GUI,
- If generation in a plant is fixed:
  - drop the turbine discharge limits (equation 4.6.1.6) for the fixed plant.
  - drop the total plant discharge limits (equation 4.6.1.9) for the fixed plant,
  - drop the generation limits (equation 4.6.1.13) for the fixed plant,
  - add the constraint that fixes generation to the LRB schedule (equation 4.6.1.14) for the fixed plant.

- If "*Maximize Profit*" objective function is selected, then
  - add the objective function (equation 4.6.5.1),
  - add the load-resource balance equation (4.6.5.2),
  - add the additional constraints (equations 4.6.5.3-4.6.5.8),
  - drop the generation limits (equation 4.6.1.13) for all plants,
  - add the optional constraint that fixes optimized storage at the last time step (equation 4.6.5.9), if selected by the user in the GUI,
  - read the objective function coefficients $NSSPrice_{mt}$, MVW_j , TIC_t, from a text file generated by the GUI in AMPL syntax,
  - read the thermal generation limits $GTher^{Min}{}_t$, $GTher^{Max}{}_t$, total gas quantity contract $BTherTotal$, the thermal unit commitment $CTher_t$, from a text file generated by the LRB system in AMPL syntax,
  - read the tie line export transfer limits $NSS^{Min}{}_{mt}$, $NSS^{Max}{}_{mt}$ from the file generated by the GUI in AMPL syntax,
  - read the real-time operating reserve obligation $G^{ORO}{}_j$ and the regulating margin requirement RMR contingencies, from a text file generated by the GUI in AMPL syntax,
  - If generation in a plant is fixed:
    - drop the turbine discharge limits (equation 4.6.1.6) for the fixed plant.
    - drop the total plant discharge limits (equation 4.6.1.9) for the fixed plant,
    - drop the generation limits (equation 4.6.5.6) for the fixed plant,
    - drop the regulating margin requirement constraint (equation 4.6.5.7) for the fixed plant,
    - add the constraint that fixes generation to the LRB schedule (equation 4.6.1.14) for the fixed plant.

7. Once the optimization model is formulated, and all input data are loaded into memory, the problem variables (initial basis) are set to those calculated by the simulator and/or saved from the LRB and the GUI.
8. Select the CPLEX Primal algorithm and set AMPL and CPLEX directives (e.g., turn AMPL's direct substitution method on; turn Presolve on, etc.).
9. Write Presolve messages and source of infeasibility, if any.
10. Invoke CPLEX to solve the optimization problem by issuing the '`solve`' command in AMPL syntax.

If the problem is infeasible, then the optimization run is terminated and the simulation results and the reports on unfeasibility are transferred and displayed to the user at the client's workstation by the Results-Display software. If the problem is feasible, then go to Step 4 to continue the solution algorithm.

Step 4: Iterate for Convergence of Forebay Levels.

Once the first optimization run is complete, the optimal unit commitment for each optimized plant is determined. As mentioned in Section 4.5, one of the main assumptions in operating a plant, given the number of units available, is that an optimal unit commitment is made to load individual units. To determine the optimal unit commitment, a database search procedure has been utilized. The procedure searches a modified, preprocessed, version of SPUC database that contains the plant load, the combo number that represents minimum plant turbine discharge for each unit availability and each plant's forebay level. The algorithm used to select the optimal combo is outlined in Annex E.

Once the optimal unit commitment is selected, the simulation is re-run, using the generation schedule computed by the linear programming model and a new set of coefficients for the piecewise linear generation production curves are computed for input to the next optimization run.

To account for variations in downstream tailwater levels other than those assumed in SPUC and for spills from a reservoir, a tailwater correction algorithm has been formulated. As mentioned in Section 4.5, SPUC database was calculated assuming a fixed downstream water level ($DSWL^{SPUC}_{jt}$), which represented a downstream water level under normal operating conditions of the hydroelectric facilities, with no spills. To correct for variations in downstream water levels at time step t ($DSWL^{OPT}_{jt}$), and for any type of spills (QS_{jt} and QSF_{jt}), the tailwater level of plant j is calculated using equation 4.6.2.15, for both the assumed (TWL^{SPUC}_{jt}), and the optimized (TWL^{OPT}_{jt}) downstream water level. As shown in Figure 5.3, the tailwater level adjustments can be mathematically expressed as follows,

$$TWL^{SPUC}_{jt} = f(f(DSWL^{SPUC}_{jt}), QT_{jt}), \tag{5.1.1}$$

$$TWL^{OPT}_{jt} = f(f(DSWL^{OPT}_{jt}), (QT_{jt} + QS_{jt} + QSF_{jt})). \tag{5.1.2}$$

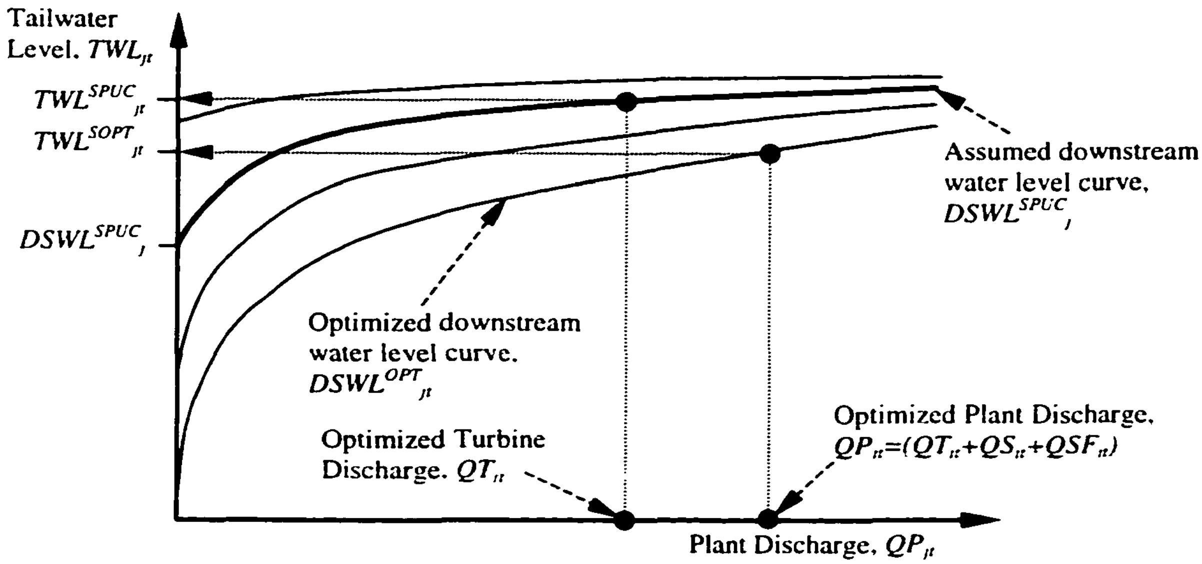


Figure 5.3 Adjustments for Variations in Tailwater Level.

A correction of the forebay level FB_{jt} is then made to account for the drop or rise in plant head resulting from variation in downstream water level as follows.

$$FB_{jt} = FB_{jt} + (TWL^{SPUC}{}_{jt} - TWL^{OPT}{}_{jt}) \,. \tag{5.1.3}$$

Note that the above equations consider the turbine discharges from a plant. rather than from individual powerhouses in a plant as indicated earlier in equation 4.6.2.15. This simplification is valid for STOM purposes, since adjustments for head variation in individual powerhouses only yields marginal improvements in modeling accuracy (at most a few centimeters) compared to the variations resulting from fluctuations in downstream water levels and spills.

Once the correction for the tailwater level is made, the forebay levels are then used to update the piecewise linear coefficients and the plant's generation and turbine limits. The initial basis from the previous optimization run is then updated. A number of iterations are performed (typically 3-6 using the Barrier algorithm) until the reservoir forebay levels stabilize and converge to a given tolerance. The convergence *Tolerance* has been determined from experience in running STOM for different time frames and for different objective functions and solution methods. It is currently set as a function of the number of hours in the study as follows:

$$Tolerance * T/168, \tag{5.1.4}$$

where *Tolerance* is currently set at to 5, and T is the number of hours for the study. In all cases the maximum number of iterations is set not to exceed 8 iterations.

To accelerate the forebay level convergence, an algorithm called the "Storage Limits Shrinking Envelope" has been tried with some degree of success. Basically, the algorithm lowers the maximum and increases the minimum storage limits in iterations. as long as the shrinking of the storage limits does not impose additional costs in the objective function. The shrinking method starts by calculating the cost of the hourly storage constraint (equation 5.6.1.15) after the first iteration (after the second optimization run). These values are determined from the dual values of the storage constraint, and are assigned to the parameter

$Storage\_Limit.Dual^{Iter(1)}{}_{jt}$. Then, the new maximum storage level $S^{Max}{}_{jt}$ for each reservoir j at each time step t is set to equal the original maximum storage limit, less half the difference between the maximum storage limit and the optimized storage level (S_{jt}) in the previous iteration, as illustrated in Figure 5.4,

$$S^{Max}{}_{jt} = S^{Max}{}_{jt} - (S^{Max}{}_{jt} - S_{jt})/2. \tag{5.1.5}$$

Similarly, the new minimum storage limit $S^{Min}{}_{jt}$, for each reservoir j at each time step t, is set to equal the original minimum storage limit plus half the difference between the optimized storage level (S_{jt}) and the minimum storage limit in the previous iteration,

$$S^{Min}{}_{jt} = S^{Min}{}_{jt} + (S_{jt} - S^{Min}{}_{jt})/2. \tag{5.1.6}$$

The limits are then updated for each plant and each hour until the total constraint's dual value ($Storage\_Limit.Dual^{Iter(n)}{}_{jt}$) in the current iteration, n, exceeds that in the first iteration, or the maximum number of iterations is reached. If the constraint's dual value in the first iteration is exceeded, then the limits are reset to their value in the previous iteration (n-1) and the plant(s) that causes additional costs is dropped from the procedure in the current iteration. Mathematically, the algorithm logic can be captured as follows,

Experimentation with the "Storage Limits Shrinking Envelope" algorithm indicated that the convergence of the forebay levels progresses much faster (by about three iterations less) than that of just repeating the optimization runs. It has also yielded more stable optimal generation schedules in successive iterations, particularly for systems that contain very small reservoirs with large upstream turbine discharges (e.g., PCN and GMS). The algorithm, however, is not yet fully implemented in STOM, pending further testing and verification.

$$for\ \{j\ in\ plant\}:$$

$$\left[\begin{array}{l} If\left(\sum_{t=1}^{T} Storage\_Limit.Dual^{Iter(n)}{}_{jt} \geq \sum_{t=1}^{T} Storage\_Limit.Dual^{Iter(1)}{}_{jt}\right),\ then \\ \left\langle \begin{array}{l} S^{Max.Iter(n)}{}_{jt} = S^{Max.Iter(n-1)}{}_{jt}; \\ S^{Min.Iter(n)}{}_{jt} = S^{Min.Iter(n-1)}{}_{jt}; \\ set\ plant = plant - j; \end{array} \right\rangle ;\ else \\ S^{Max.Iter(n)}{}_{jt} = S^{Max.Iter(n-1)}{}_{jt} - (S^{Max.Iter(n-1)}{}_{jt} - S_{jt})/2; \\ S^{Min.Iter(n)}{}_{jt} = S^{Min.Iter(n-1)}{}_{jt} + (S_{jt} - S^{Min.Iter(n-1)}{}_{jt})/2; \end{array}\right];$$

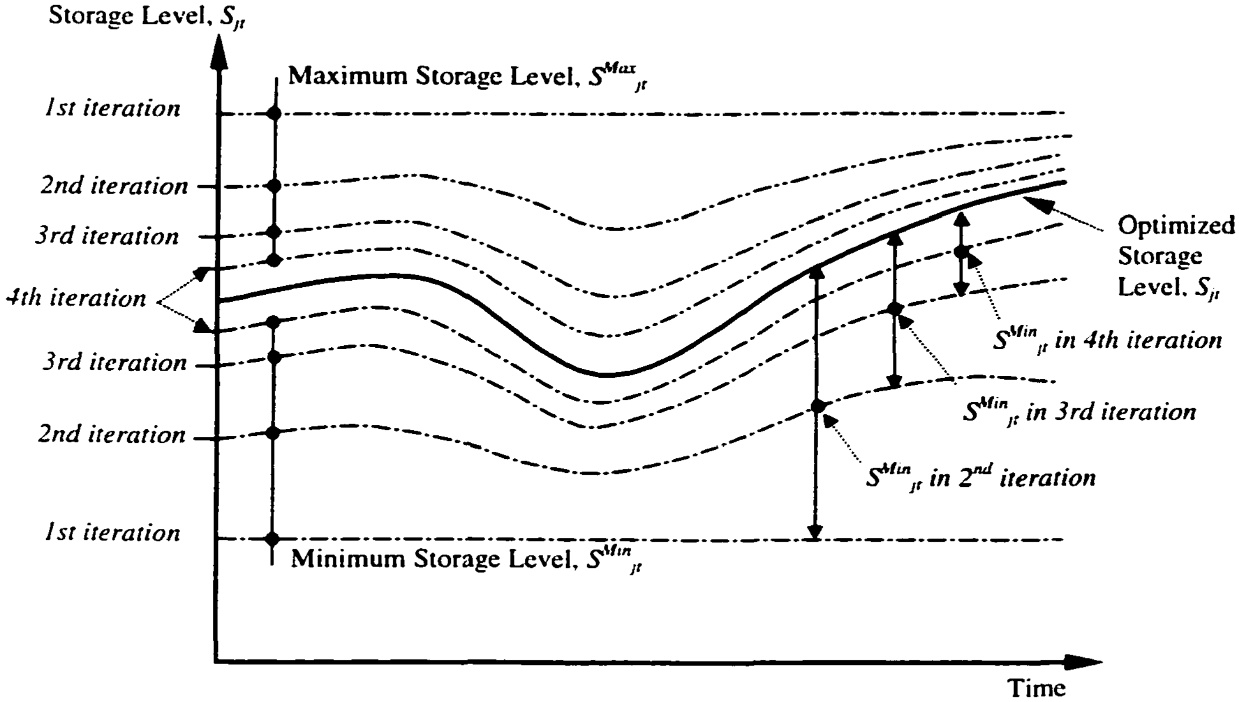


Figure 5.4 The Storage Limits Shrinking Envelop Method

Step 5. Solve the Primal or Dual Optimization Problem

In this final step, the optimization problem is formulated for and solved by CPLEX's Primal (or Dual) algorithm (depending on the objective function). In this final optimization run, the optimal unit commitment and the tailwater adjustments (and the maximum and minimum storage limits when the "Storage Limit Shrinking Envelop" algorithm is used) determined in the final iteration in Step 4 above are used. The final solution results and sensitivity analysis information are written to text output files. The simulation and optimization output files are then transferred to the client workstation and displayed to the user using the Results-Display software.

5.2 THE IMPLEMENTATION PROCESS

This section discusses the important issue of implementation of the decision support system. The section starts with an overview of the implementation roadblocks for short-term optimization models. This is followed by a discussion on the factors that have contributed to the successful implementation of STOM, with emphasis on the implementation process followed in this study.

5.2.1 Implementation Roadblocks

It has been known for quite sometime now that short-term optimization models have rarely been used by the people who actually manage complex reservoir systems in real-time. There are several reasons. First, most models was not easy to use as the computer technology needed to model complex hydroelectric systems were not capable of meeting the needs of the end-user in terms of ease of use and the time it takes to run them. Second, most of the models were developed for specific studies (mostly academic) and did not reflect enough of the complexity and flexibility that was required by the end user. Third, and as given in a landmark article by Yeh (Yeh, 1985), the people who can and do apply optimization techniques are generally working at an "academic", abstract level that operators, accustomed to taking direct responsibility (and risk) for their day to day operations have difficulty relating to. Fourth, operators do not always understand the esoteric theory and often do not accept the simplifications necessary to match the available techniques to the situation at hand. Fifth, it simply takes considerable amounts of time, patience, and effort to develop, calibrate and operationally implement such complex models in real life situations.

Despite all of the above difficulties, STOM was developed, calibrated, and implemented through a team effort of the BC Hydro's staff, researchers and several students from the Civil, Electrical, and Computer Science Departments at the University of British Columbia (UBC). Factors which contributed to the successful development and implementation of STOM will be discussed next.

5.2.2 Implementation Process and Success Factors

It is difficult to initiate a new way of things in a large organization, particularly when the existing system still seems to be working well. The implementation of a decision support system is, in effect, the introduction of change in an organization. It is complicated long, tedious, ongoing process that is vaguely defined and that covers all phases of development, from initial prototyping to institutionalization of the new system. Although many researchers have studied issues relating to the success or failure of computer-based decision support systems and have provided useful insights, yet the theories, methods and procedures developed over the years do not guarantee success in real-life situations (Turban, 1998; Turban, 1990). However, several factors that contribute to the successful implementation of computer-based decision support systems have been identified by Turban et al. These, along with other factors that were found critical for implementation of STOM have been grouped in ten categories, as shown in Figure 5.5 and discussed below.

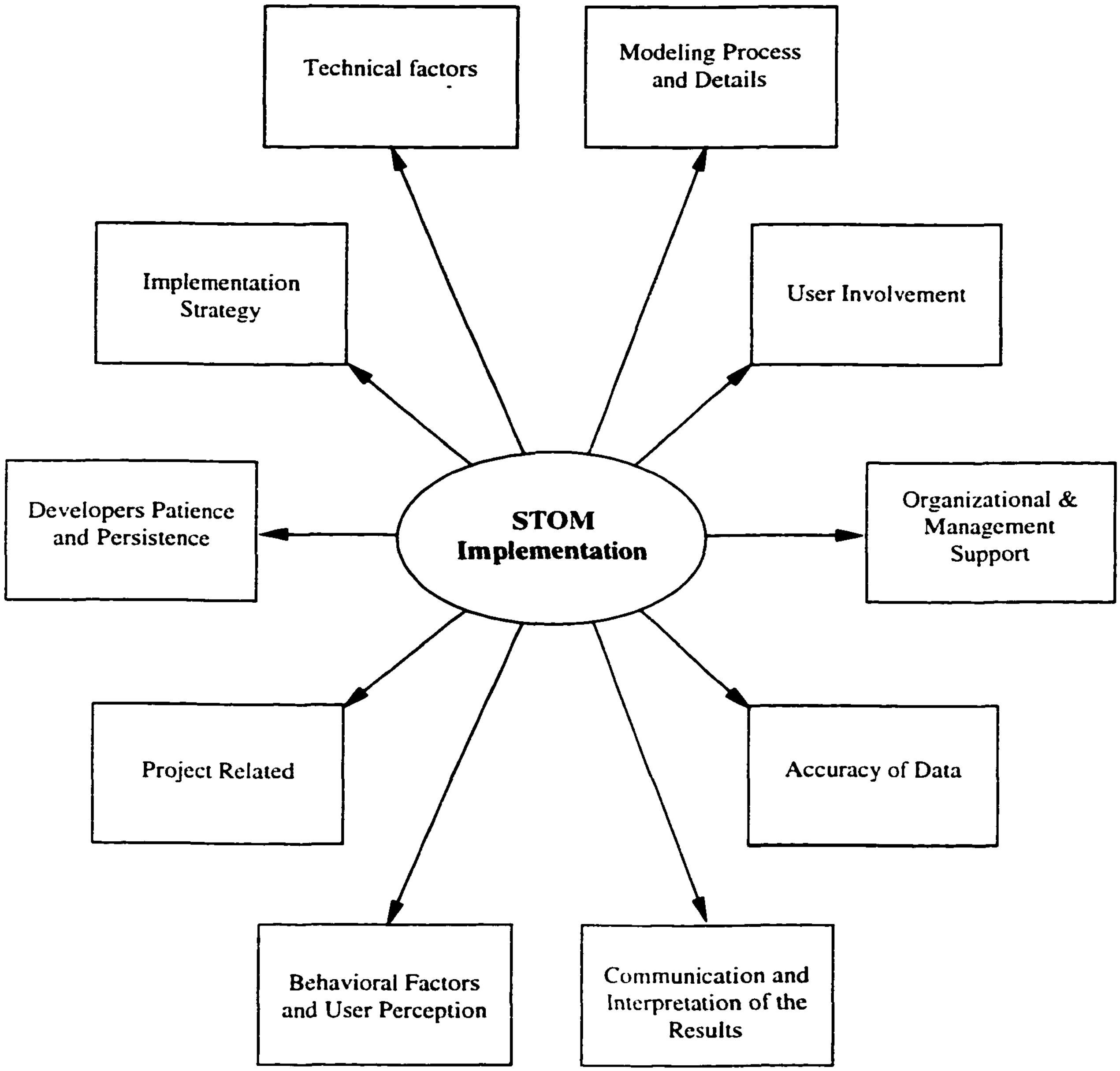


Figure 5.5 Factors Contributing to Successful Implementation of STOM.

Source: Adapted from Turban, 1990; Turban, 1998.

i. Technical Factors

Technical factors concern limitations of available computer technology and scarcity of technical resources available for developing and implementing STOM. Limitations of available technology includes computer software and hardware as well as the solution algorithms that can beneficially be used to solve the optimization problem and provide reliable results in the fastest time possible. Scarcity of technical resources, on the other hand, includes locally available expertise on model building and computer programming given financial resource limitations. The following brief discussion addresses the above issues.

a. Selection of the Simulation/Optimization Modeling Environment

A key question in developing a model for a particular system is whether to use an existing generalized hydroelectric model, to modify an existing model, to develop a new program using one of the programming languages (such as Fortran, C, or Visual Basic), to construct a model using a general purpose commercial software program, or to use some combination or variation of the foregoing.

Formulating new optimization algorithms, writing and debugging the code, and testing new programs is expensive and time-consuming. Using an existing generalized software program is typically much easier than developing a new one, but still considerable development effort may be required to adapt the generalized software to the system at hand. Generic linear and non-linear programming solvers are available, but the use of such optimization solvers typically still involves significant computer programming effort to adapt the real-world problem to the required mathematical format and to manage input and output data.

Soon after B.C. Hydro approached UBC researchers, a compilation of available methods of analysis was done. It then became apparent that the B.C. Hydro's system is unique and to meet the optimization modeling requirements, linear programming seemed to be best suited to the reservoir and energy management problem (see Chapter 2 for more details). To test the applicability of the linear programming technique, several simple prototype models were formulated and solved using Excel's built-in Linear Solver. The prototype models helped to convince B.C. Hydro's staff, and the research team, that linear programming was the way to go. Adding complexities to the model, however, required the use of more advanced modeling techniques and linear programming solvers. Review of the literature and the "Web" and consultation with several UBC operations research professors and students indicated that there was a set of robust and well tested modeling languages and linear solvers. Several commercially available software packages (AMPL and GAMS as modeling languages, and CPLEX, OSL and Minos as solvers), were reviewed in terms of their features, costs, technical support, algorithmic methods, etc. In consultation with the project management at B.C. Hydro, the AMPL modeling language and the CPLEX solver were selected.

To test the AMPL and the CPLEX software packages they were first purchased and installed on the Sun computer system in the Civil Engineering Department, UBC. The Excel prototype model was then translated using the AMPL modeling language, and the problem was solved using the CPLEX linear solver. B.C. Hydro operations engineers provided a set of input data to test the optimization models. Several runs were then performed for the four largest plants and the models and output results were then demonstrated to B.C. Hydro staff. Upon review of the runs results, B.C. Hydro staff were convinced of the potential use of the two software systems and subsequently purchased and installed them on a dedicated Windows NT server.

As for the simulation model, B.C. Hydro required the development of a detailed hydraulic simulation model that could be used by STOM as well as a stand-alone system. B.C. Hydro favored the use of either the Fortran or the C programming languages. The simulation model was developed using the C programming language for two main reasons. The first was due to the availability of students with fairly good background in the C programming language, and the second was due to some of the special features of the C programming language (use of pointers, computational speed, etc). The coding of the model was carried out by a number of UBC graduate and undergraduate students from the Civil Engineering Dept., and a Co-op student from the Computer Science Dept. The students worked under the direct supervision of B.C. Hydro operations engineers and the UBC research team (for more details on the simulation model, see Section 4.3.4).

b. Selection of the Server-side Computing Environment

At the initial stages of STOM development, and after the decision has been made to use AMPL and CPLEX as the main modeling and optimization engines, extensive discussions were held on the most appropriate computing environment for STOM implementation. The discussion focused on whether to use a mainframe or desktop-computing environment for the simulation/optimization runs. At the beginning, B.C. Hydro staff and management preferred the mainframe environment. However, several consultations with computing experts in B.C. Hydro, UBC, and operations research professionals (particularly CPLEX and AMPL developers), it became evident that the "way of the future" is to go with the Windows NT operating environment.

Several factors favored selection of the Windows NT operating environment. First, the cost to purchase AMPL and CPLEX for Windows NT is about US$12,000 for a single process. In addition, CPLEX developers were hesitant to license CPLEX for the open VMS operating environment (Digital Equipment Vax system), since they would not be able to control the number of processes running at any instance. In addition, the cost to purchase AMPL and CPLEX for the open VMS computing environment could be as high as US$100,000. Second, the processing speed and the size of random access memory (RAM) for desktop-based computers are approaching those of medium sized mainframe computer workstations (e.g., Digital Equipment Alpha systems running at about 500 MHz, and 500 MB of RAM), at a fraction of the cost. It has been said that the speed of Intel (or similar) processors are doubling every 18 months or less (e.g., when the project started 100 MHz processor was top of line, two years later, 450 MHz processors are available in market). Third, an advantage of using the Windows NT operating environment was the availability of the modules that perform the remote procedure calls and the ease of adapting these modules for use by the communication protocols developed for STOM by a team of UBC Electrical/Electronic Engineering students. Fourth, the functional requirements dictated that any user with access to the B.C. Hydro computer network could use STOM. This has required the use of a server-computing environment such as Windows NT. Fifth, the cost of purchasing, upgrading and maintaining an Intel-based desktop Windows NT server is negligible (about $5,000 to purchase) in comparison with a medium sized mainframe systems (about $120,000 for the

Digital Alpha server). The low cost of the Windows NT server system has also allowed for a dedicated system to be allocated solely for the use of STOM.

b. Selection of the Client-side Computing Environment

Decision on the client-side computing environment was much less troublesome, since most engineers (and the Shift Office) use the Windows 95 operating environment in their daily operations. The Windows 95 computing environment has also allowed development of a user-friendly STOM interface in Visual Basic, the communication protocols in C and Visual C++ programming languages, and the Results-display software in Visual Basic for Excel (see Sections 4.3.2, 4.3.3 and 4.3.6 for more details).

c. Technical Resources

One of the main obstacles to developing the set of software programs for STOM was the enormous amount of computer programs that needed to be coded, and the modeling details that needed to be addressed. It was evident from the start that to develop a robust system would require a large number of person-hours and considerable sums of money. For these reasons, and due to limited financial resources available for the project, UBC graduate and undergraduate students carried out most of the work under the guidance and direction of BC Hydro operations engineers and the research team at UBC. The students were either hired directly by B.C. Hydro (through the UBC Co-op program), or they were hired directly by UBC. This arrangement worked very well for both B.C. Hydro and the students. B.C. Hydro has benefited in two ways: financially, and technically. Financially, it was much cheaper to hire students to do the prototyping and formal modeling work. From a technical point of view, B.C. Hydro was able to acquire up-to-date technical methods in prototyping and building STOM components and other supporting software systems. The arrangement has also helped B.C. Hydro in recruiting new blood into the organization, as some of the students ended up working for B.C. Hydro. For students, it provided an excellent learning environment and financial help for their graduate and undergraduate studies.

ii. Modeling Process and Details

Any applied modeling process should be approached with lots of common sense – something which engineers are supposed to be good at. For the applied modeling process to be successful, it should follow the requirements and understanding of the problem-to-be-modeled owners. For this reason, the full team of managers, end-users, modelers, and system-to-be-modeled experts should be involved and be able to understand the basics of the modeling principles and methods to be used.

The first step in setting up a modeling process is to understand the system to be modeled and the decisions that will be based on its output. This is not an easy step to achieve, since the objectives of the model could be interpreted differently by each of those involved in the process and by the model users. The objectives of modeling can also change without notice. For this reason it pays to develop a very simple prototype model and to get the team of people involved to scrutinize it, take it apart, and then agree on what should be modeled. The prototype model can also serve to clarify what is needed for the full-scale model and what is involved in terms of input data required to run the model.

Next a thorough understanding of the system to be modeled is essential. This is also difficult. The modeler should rely on the experience of the system-to-be-modeled experts in the organization, and should be very careful about challenging the wisdom of experienced members.

As the saying goes, "the devil is in the details." As indicated in the user's functional requirements, it was required that STOM should accurately model the hourly operation of a very complex hydroelectric system. Since the users of STOM are operations engineers who manage every aspect of the system, the mathematical representations of the hydroelectric facilities had to be very accurate, as detailed in Section 4.5. It was recognized at the outset, however, that too many details could easily overwhelm the modeling process and the data needed to run the model. For this reason, it was decided that STOM should model only what was absolutely required, particularly during the early stages of its development.

Starting with a low level of detail and incrementally adding user-requested functions (to make it more responsive to the user's requirements) not only allowed the complex model to be manageable, but have also played an important role in allowing the end user to actively participate in the STOM development and implementation process.

Aggregation and generalization of system representation played a major role in keeping input data requirements and modeling details to a minimum. The major aggregation that was adopted in STOM was to model generation at the plant level, rather than at the unit level. This modeling methodology significantly reduced the level of detail in the model and allowed the use of some of the important features of the generation production function and the linear programming technique as discussed in Section 4.5.

As indicated in the discussion on the curve fitting procedure for the generation production function (Section 4.5.2), the decision to use three piecewise linear segments illustrates the tradeoff between simplicity and accuracy. First, higher accuracy of the generation production function representation could be achieved by matching the number of segments in the piecewise linear curve with the number of generating units in a plant. The higher accuracy, however, would require a more complex curve-fitting procedure, which could be hard to maintain in the future. Second, as the number of piecewise linear segment increases, so does the number of variables and constraints in the optimization model, which makes the optimization problem harder to solve. Third, if the number of piecewise linear segments were to vary for each unit commitment, additional coding would be required in the hydraulic simulator and the optimization models and their input data structures.

Several benefits were realized from generalization of system representation. First, it allowed the user to formulate the model dynamically, which could be considered as one of the innovative features of STOM. Second, it significantly facilitated the numerous revisions of the model to accommodate user's requests and requirements. Third, it allowed the user to modify the model through a user-friendly interface (see Section 4.3.2 for details). Fourth, it allowed the model to be formulated in an easy to understand form, which also made explanation of the model to the user and to B.C. Hydro staff easier. Fifth, and through the use of the AMPL modeling language and the incidence matrices (described in Section 4.5), the entire generalized model formulation is only about seven pages long, which makes the optimization model easier to maintain, debug and modify in the future.

iii. User Involvement

It is believed that user involvement contributed almost 50% to the successful implementation of STOM. Many B.C. Hydro staff, including the shift engineers, were directly involved in setting out the functional requirements and modeling details that captured the physical as well as the operational characteristics of the generating system. The users and several B.C. Hydro staff members were involved in all phases of development and implementation of STOM:

- the planning phase,
- the design phase.
- the testing, verification and implementation phase.

a. User Involvement in the Planning Phase

In the planning phase the focus of the interaction with B.C. Hydro staff was on the computing environments and modeling technologies to be used (as discussed in the "Technical Factors" above), on getting agreement with B.C. Hydro on what is going to be modeled, on sources of data, and on the objective functions for the optimization models.

During this phase the prototype models (using the Excel Linear solver) were developed and used to assess the applicability of the linear programming technique for the optimization models. The prototype models were also used to initiate discussion within B.C. Hydro on the most appropriate objective functions for the optimization models. One particular objective function played a major role in convincing many engineers of the benefits of using optimization techniques for short-term scheduling of hydroelectric facilities. In this objective function, the reservoir levels were constrained to start at and end up at their scheduled levels. By maximizing the efficiency of the generating plants and manipulating the reservoir's water levels, the optimization model was able to generate more energy, yet still meet the system constraints, and end up at the same scheduled reservoir levels. This demonstrated that a relatively simple optimization model (as it was then) could produce more energy from the existing system than could the experienced operator who had drawn up the schedule. It also suggested that additional benefits could be achieved from improving the system representation and accuracy of the model.

During the planning phase the first draft of the mathematical model for the four major plants in the BC Hydro system was also formulated. The mathematical model formulation was iterative in nature, and it involved several sessions with experienced system operations engineers in an effort to flesh out the required modeling details. In these sessions the required input data was also assessed. The model's input data was divided into two categories. The first category concerns physical input data, which describes the characteristics of the hydroelectric facilities, while the second category concerns operational input data, which describes the current status of the system (see Sections 4.3.1 and 4.5 for more details).

Once the prototype optimization models were formulated using the AMPL/CPLEX software packages on the Sun computer system in the Civil Engineering Dept. and once it was demonstrated that the optimization models produced accurate and reliable results for the four major plants, the focus was shifted to expand the optimization models and to initiate the design and implementation phase of the project.

b. User Involvement in the Design Phase

In the design phase the focus of interaction with B.C. Hydro staff was on assessing the required components to make the optimization model operational, on how to generalize and expand the optimization model for other major hydroelectric facilities in the B.C. Hydro system, on ways and means to check and verify the physical input data, and on how to mesh the optimization model into the LRB system.

The first step in the design phase was to arrive at the required components and the preliminary structure of the decision support system and how they were going to be meshed into the LRB system. Arriving at the required components involved discussions with several B.C. Hydro staff members, which included the LRB system designers and programmers as well as operations and computer network engineers responsible for the design and implementation of the software and hardware systems for the newly formed Shift Office. From these discussion and debate sessions the author was able to define a preliminary set of functional requirements for the decision support system (see Section 4.2.1 for more details). These functional requirements served as a set of "standards" for the system, and they were expanded as development and implementation of the system progressed.

The second step in the design phase was to determine the technical details and technical expertise needed to carry out the work for other components of the decision support system. The components included the graphical user interface, the hydraulic simulation system, the communication protocols, the results display software, and the computer code to save and check the integrity of the operational input data.

By this time the workload in the project had expanded and a division of labour was required. Other graduate and undergraduate students were recruited and hired to form a research project team. Each member of the project team performed his/her work in close coordination with other team members and with B.C. Hydro staff. This arrangement helped the team members to learn what was going on in the project (and to learn in the process). It also helped B.C. Hydro staff to stay in close touch with the research project. Several group and one-to-one discussion sessions were held with system operations engineers, computer network engineers, and computer programmers to come up with the preliminary design features of the graphical user interface, the communication protocols, the simulator, and the results display software. The discussions resulted in numerous changes until these software systems were finally performing the functions they were intended to.

In the design phase, the optimization model was generalized to include the major hydroelectric facilities in the B.C. Hydro system and extensive testing of the optimization and simulation models were carried out. A set of tests using the 1996 historic operational input data, which covered operations modes for most of the year, revealed some inconsistencies and errors in some of the physical as well as the operational input data. They also uncovered some major and minor bugs in the simulation and optimization models, which were corrected as the tests progressed.

Needless to say, errors and inconsistencies in operational and physical input data required much work from the project team (see "Accuracy of Data" for details). It also caused some delays in implementing the decision support system at the shift office for real-time use.

Although management were keen to go ahead with the implementation phase, the author preferred to delay implementation of the system for use in real-time operations until the major problems with the physical and operational input data had been resolved and until the system was behaving in a way acceptable to the end-user. Otherwise, it was thought, reluctant users would find good and justifiable reasons for not using STOM and the system could end up shelved somewhere in the organization. Fortunately, by the end of the design phase the components of the decision support system were finally coming together and behaving sufficiently well to be presented to the end-user.

c. *User Involvement in the Implementation Phase*

This implementation phase was critical, as it could determine whether the system developed so far met the requirements and expectations of the seven shift engineers –the main users of the system. In this phase the initial focus was on training the shift engineers on how to prepare the input data and how to use the system in their daily operations. Most of the shift engineers were very interested in STOM. In particular, some of the shift engineers were heavily involved in development of other software systems that were being put together for use in the new Shift Office. Their knowledge of the requirements of other engineers (in terms of ease of use of the GUI and displaying the output results) was exploited to arrive at the initial release of the graphical user interface and the results display software. They also provided considerable help in formulating the operational input data checklist contained in Annex B, and in conducting several test runs before STOM's initial release.

During the training sessions the focus of the end users was on assessing the benefits of using STOM in their daily operations and how it could be integrated with the other tools that they use. It also involved testing, verifying, and understanding its outputs. In addition, and as the shift engineers started to interact with the system, their feedback required significant modifications to the graphical user interface, to the results display software, to the simulation and optimization models, and finally to the physical and operational input data.

At the initial stage of implementation, the training sessions were structured by management of the Shift Office so that the shift engineer who was working on the previous day(s) shift would run a postmortem study of the schedules dispatched. In these training sessions the objective function that maximizes the efficiency of the system was used. This objective function was selected for its ease of use as it requires minimal input data from the user. This structure of training sessions significantly highlighted the benefits and the drawbacks of STOM. On the benefits side, it showed the shift engineers what could have been done to maximize the efficiency of the system (rather than maximizing the efficiency for individual plants), while their schedules were still fresh in their minds. In many instances the shift engineers would either justify their schedules, thereby indicating a shortcoming or missing modeling detail, or question the logic of the optimization model, in which case a detailed analysis of the output would be carried out. In both cases the benefits gained from the exercise significantly improved the model and its understanding by the user. In the process of preparing the input data and reviewing the results, the shift engineers would also criticize the data preparation process, the GUI, and the results display software, or they would request additional features to be included in them. At the end of each postmortem run, the shift engineers were required to prepare a short report on their findings. The reports were distributed to their colleagues for information and feedback. In many instances these short reports stirred an extensive discussion, and in many cases resulted in revisions to the optimization model or other software systems that they use.

The first stage of implementation also highlighted some of the drawback in the procedures used to check and verify STOM's input data. It also highlighted the need for more staff in the shift office to perform optimization and simulation studies in real-time. To test the potential use of STOM and other software systems (e.g., the unit commitment program) for real-time scheduling, the shift engineers were asked to test the "maximize the profit" objective function in real-time operations mode while acting as a second shift engineer alongside the first shift engineer. After this test by the majority of the shift engineers, it became evident that there could be significant gains in having more staff whose main focus would be to run STOM and other optimization and simulation models to prepare the schedules for the first shift engineer. Following this exercise three additional shift engineers have been added. Their main function (starting mid of October 1999) will be to focus on running STOM and other simulation and optimization models to aid the process of preparing the generation and trading schedules by the shift engineer.

The second stage of implementation focused on acquiring marketing information from PowerEx, on modifying the LRB system to read and write the marketing information, and on training the shift engineers on the use of the other objective functions of STOM, in particular the maximize profit objective function. Several shift engineers and the manager of the shift office were involved in setting some of the modeling details and input data requirements for the "maximize the profit" objective function. It also involved revision of the procedures used to check and verify the required operational input data for STOM.

The third implementation stage was scheduled to take place in May 1999. The focus of the third stage was on full implementation of STOM at the shift office for real-time use.

In summary, training on the system and user involvement helped to achieve the following:

- assessing the importance of checking and verifying input data,
- validating the model for operational use,
- understanding of the model by the users,
- assessing additional modeling details requirements,
- enhancing the user-friendliness of the GUI and the results display software,
- highlighting the need for more individual and group training,
- assessing the need for additional staff to run STOM in real-time operations mode, and
- assessing the benefits of STOM.

iv. Organizational and Management Support

This research project was carried out with a relatively low profile. For this reason it was looked upon by those with a little knowledge of the project, as another research project likely to end up producing something that probably could be used. Due to its low profile only few people, who were directly involved in the project, knew about what was going on in the project (up until the models were in actual implementation phase). For this reason the research project did not encounter significant resistance from persons within the organization, or to put it in the operations research jargon, it did not encounter "tactics of counter implementation" (Turban, 1990).

Fortunately, the managers and senior operations engineers who knew what was going on in the project fully supported it, as they were fully convinced that it was "the way to go" in developing complex models for a complex hydroelectric system.

An other factor that may have contributed to the successful implementation of STOM was that the researchers involved in the project were not B.C. Hydro employees and were shielded from organizational politics. This was despite the fact that most of the research was conducted on B.C. Hydro premises, and the researchers were given full access to all facilities available to B.C. Hydro employees.

Support of top management to institutionalize the decision support system and to integrate it with other operational tools used by the Shift Office also played a major role in the success of STOM implementation. As the research project progressed, and as the initial implementation results showed the benefits of using STOM by the Shift Engineers, top management provided additional financial and technical support for the research project and for implementation of STOM in the shift office for real-time operations. STOM was even included as one of the main projects under the Business Transition Plan that BC Hydro is currently implementing to prepare the organization for the new electricity market structure.

Finally, the factor of luck should not be ignored. Two of the main advocates (who originally approached UBC) for developing and implementing STOM became the managers responsible for its implementation. The two managers also have very good relationship with the manager of the research project.

v. **Accuracy of Data**

"Garbage in, garbage out", is the famous saying that is often used in operations research jargon to reflect the importance of input data in any modeling exercise. STOM is no exception. STOM is an operational tool that relies on its user to ensure the accuracy and integrity of operational input data. For STOM to be used effectively and reliably by the system operations engineers at B.C. Hydro a reliable and accurate database was required. It was also required that STOM should be fully integrated with the LRB system, and it should closely model the current status of the system.

Several steps were taken to meet these requirements. First, the process of acquiring and checking the operational input data was separated from that for the physical input data. Second, the physical data was collected, checked, derived, stored in the required format for the simulation and optimization models, and then calibrated for operational use. Third, to extract STOM's operational input data several computer software modules were inserted into the LRB system, or were developed to prepare the required input data. Fourth, STOM GUI was designed to allow the user to set and review some of the study's parameters and limits as discussed in Section 4.3.2.

Several procedures were formulated to check and verify operational input data, as shown in Annex B. In addition, the GUI was designed to read and rewrite the operational data for the plants selected and for the duration of the simulation and optimization study. In the process of rewriting the operational input data, the GUI performs the following functions:

- check for errors in input data (e.g., non-numeric input),
- check for missing input data,
- check for violations of operational limits (e.g., starting reservoir levels are outside their limits, total available generation capacity meets the load and the prescheduled imports and exports).

If an error or a violation of the limits is detected, the GUI lists and displays them to the user and quits the run.

Several types of operational data problems were encountered during the implementation process of STOM. The types of problems and the solution adopted are summarized as follows:

- Incorrect data due to inaccurate, or careless data entry. The solution was to develop a systematic way to ensure the accuracy of data (e.g., summarized checklist as attached in Annex B), check data integrity, and report any problems to the user before submitting the run (e.g., check and rewrite data for plants selected and for the duration of the study). In the case of derived data, the problems were investigated and corrected with the aid of the shift engineers and the team of computer programmers responsible for maintenance of the LRB system.
- Data not available. Highlight the problem and aid in the development of software systems to generate data in the required format, or, when possible generate data internally.
- Errors in data measurement. Investigate the source of discrepancy and suggest ways to correct for it (e.g., the PI data is actual measured data, which contains noise and sometimes errors).
- Data does not exist. Come up with best estimates with user suggestions.

The research team spent many months on acquiring, deriving, verifying, and calibrating the physical database used in STOM. This effort resulted in the creation of one of the most accurate physical set of data on hydroelectric facilities in B.C. Hydro. The main focus of this effort was to ensure that STOM relies on the most recent and technically correct set of data that exists in the organization. As can be imagined, the work was tedious, as it required interaction with many staff members and in many instances manually "mining" the data out of old as well as new data sets to extract the information needed for STOM.

vi. Interpretation and Communication of Results

Meaningful, understandable, and conveniently obtainable displays of results are necessary if a model is to be useful for operational use. As discussed in Section 4.3.6, the Results-Display Software was developed in close coordination with the end-user. In addition to the extensive numeric display of results, the software uses the computer graphic capabilities of Excel to allow the results to be more meaningfully interpreted. The interpretation and communication of model results also contains measures of performance of the optimization run for each objective function.

As indicated in Section 4.3.6, the results-display software allows the user to save output of the optimization run for later use or for review by others. It also allows the user to export the results to the LRB system, thereby completing the cycle of the optimization run. The summary sheet contains the most important results for a higher level view, and behavior of the run as well as a performance measure of the optimization run. Other sheets contain detailed information on each plant included in the optimization/simulation run.

The above features of the results display software allow the user to review, understand and interpret the output of the optimization run in a quick and easy way.

vii. Behavioral factors

User perception of the system was found to be very important in getting the system accepted by the majority of the shift engineers. As mentioned in the design philosophy of STOM, the user is the ultimate decision-maker, who decides when to use it, how to use it, what analysis to perform with it, and whether to accept or reject its results. In summary, STOM users have viewed it as a decision support tool to aid them in making their decisions, and not as a system that will someday replace them.

The other important behavioral factor in getting the system accepted is the user-builder relationship. All B.C. Hydro staff and in particular the operations engineers have their own jobs to attend to. The research team was careful not to excessively intrude on them, particularly when important events were taking place (e.g., sudden outage, floods, important meetings, etc). To get things done, the author adopted a semi-causal business relationship with the concerned staff, who in many instances cancelled appointments with the research team to take care of more urgent aspects of their job.

Among the other important behavioral factors is resistance to change, and how STOM users and others perceived the system in the organization. STOM was looked at by many as a link between the long/medium-term planning studies and the real-time operations, while others perceived STOM as potentially threatening to their jobs. The two views, and many in between, were not easy to reconcile. Initial perceptions are hard to change, and every effort was made to stress the point that STOM is not a replacement of its users, but rather, is a tool to aid them in making important and complex decisions, particularly in the new emerging market environment.

It was also found that when a system is perceived to have management support it gets accepted much more quickly than if it did not. As mentioned above, STOM development and implementation enjoyed considerable management support, and for this reason many viewed it as an important system to master. Finally, during the postmortem studies, it was found that the model gained acceptance when its results confirmed a decision that had already been made, or when the answers seemed "obvious".

viii. Project Related

Project related issues concerns project benefits, and whether the decision support system developed solves a problem. They also concern management of the development and implementation process as well as the necessary financial and logistical support to develop and implement the system in real-life.

a. Project Benefits

The benefits of STOM are considerable, and they can be summarized as follows. First, compilation and verification of STOM's physical input data have resulted in the creation of a very accurate database on the majority of hydroelectric facilities managed by BC Hydro. This, in the opinion of the author, is priceless. Second, the exercise of building STOM has lead to the explicit recognition of relationships that were not realized before. For example, the utilization of the concept of optimal unit commitment to derive and use the plant's generation production curves has resulted in the introduction and use of the methodology and the exploitation of its features in STOM (see Section 4.5.2). Third, although the financial benefits have been estimated by B.C. Hydro to amount to \$5 million per annum, the long-term financial benefits of using STOM are hard to quantify. This is because as the system operations engineers use STOM, they will tend to learn how the generating system should behave in an optimal manner under different operating conditions. This could possibly lead them to derive some rules that could be followed to optimize the system mentally. Thus, the returns from running the optimization model seem to diminish as the years go by, although STOM will likely be used to reinforce and reassure the experienced engineers that their schedules are optimal. However, new users will greatly benefit from running and using STOM, or from inheriting the rules derived by expert users, until they too reach a level at the learning curve where the apparent benefits diminish. Fourth, STOM acts as a unifying instrument for organizational functions. It is well-recognized in industry that one of the virtues of a corporate planning model is that many interconnections between different departments and functions in an organization have to be represented explicitly. The obvious example in STOM is the function of BC Hydro's Power Supply and the Marketing Business Units, where divergence of objectives could exist. Production could well be trying to satisfy certain requirements (e.g., meeting the domestic load, meeting reliability criteria, or environmental limits, etc), while marketing may be trying to maximize the total volume of sales rather than concentrating on maximizing profits, or value of resources. From this perspective, STOM acts as an instrument to unify the objectives of the organization, namely, to maximize the value of its resources. Fifth, the postmortem testing and user training phase on STOM showed that the gain in value of the optimized schedules varied from 0.25% to more than 1% -some in the form of additional revenue from sales and some in the value of additional stored water. Aside from the optimized schedules, one of the major benefits of using linear programming and models in general is the derived sensitivity analysis data that can be obtained. Sixth, a team of graduate and undergraduate students carried out STOM development and implementation. The benefits of using students are several fold. The cost of technical expertise to B.C. Hydro was low (in comparison with consultant fees), while the gains to BC community and the country are significant (mainly from training students on real-life problem solving techniques, and from locally developing the knowledge base and technical expertise for hydropower system operations). Seventh, STOM considerably shortens the time needed to prepare the generation and trading schedules, and the system operations engineers now can beneficially use the time saved to focus on other important aspects of their job. Eighth, STOM's operational data requirements provided significant benefits in verification, and in many instances finding sources of error in operational data sources. It has also helped in organizing and archiving operational data for use when the need arises. Ninth, STOM is a dynamic system optimizer, rather than individual plant or unit static optimizers. The key words here are dynamic and static. STOM looks into the future and optimizes the system behavior while taking future decision and system limits and constraints into account. Finally, and most importantly, STOM provides the link in the decision-making process between the long/medium-term planning and coordination studies and real-time system and marketing operations. The main drivers of STOM are market prices and the value of water resources, which are to a large extent, the main driving forces in electricity markets today.

b. Management of the Development and Implementation Process

Internally, the B.C. Hydro and UBC project management gave a high degree of freedom to researchers and other students working on the project. This created an ideal atmosphere to develop innovative solutions to the problems that were encountered in the project. It also allowed exploration of available and new methods of analysis, as developed in this thesis.

c. Financial and Logistical Support

The important aspects of financial and logistical support cannot be over emphasized, as they were very critical to the success of this applied research project. Financial support was provided to cover student salaries for graduate and undergraduate students employed on the research project by UBC, as well as the Co-op students from UBC, the University of Victoria, and other colleges in BC. Logistical support was provided by B.C. Hydro as office space and computers and other equipment, as well as arrangements to visit old and new hydroelectric facilities and control centres in the province. Finally, access to all information sources was provided with no restriction, which to a large extent contributed to the success in developing and implementing STOM.

ix. Developers Patience and Persistence

There are two virtues that every developer of a complex decision support system should possess: patience and persistence. However, it could be of value to mention that two of the main obstacles to getting a commercial optimization systems accepted and implemented in organizations which deal with complex systems are the lack of continued support throughout the development and implementation process, and the fact that complex systems (such as B.C. Hydro's) require custom built optimization models and user's interface, both of which require patience to develop and implement.

x. Implementation Strategy

As mentioned above an incremental strategy to develop and implement STOM was adopted. The strategy started with developing and solving a very simple model (using the Excel 5.0 linear solver) for the four largest plants in the B.C. Hydro system. The model was used to demonstrate the potential applicability of the technique and the benefits of modeling their short-term operations. The second stage included the use of more sophisticated modeling and optimization tool-kits (AMPL and CPLEX) for the same four plants, developing the hydraulic simulator, and design and development of the GUI. During this stage four objective functions were used to test and calibrate the model and to familiarize the shift engineers with the new decision support tool. The objective functions included maximizing the system efficiency, minimizing the value of water used, maximizing the terminal value of storage in reservoirs, and maximizing the value of extra energy that could be generated given fixed reservoir target levels. It also included sorting, classifying and verifying the physical and operational data used in the project. The third stage focused on expanding the model to include the majority of plants in the B.C. Hydro system, and to adding more physical and operational details in the model. It also involved testing and calibrating the model for real-time use (postmortem analysis of actual schedules). The fourth stage involved expanding the model by adding real-time marketing information and constraints. Upon completion of this stage the focus has shifted to use of the tool for real-time operations to determine the optimal hourly generation and real-time trading schedules in a competitive power market.

The fifth stage is still ongoing and it includes adding more detailed marketing components, transmission losses and constraints, and other operational details to the model. It also involves enhancements to other components of the decision support system, such as adding the flexibility to run multiple scenarios, and to enable the user to load input data from previous runs and compare their outputs.

Future planned stages include incorporating uncertainty in the system firm load and forecast spot prices. It also could include building rule-based expert systems to interpret sensitivity analysis output data (e.g., Greenberg, 1993). Discussions on implementing a modified version of STOM to prepare the system operation plan and for use by the project planning engineers to prepare preliminary optimized schedules for individual river systems are underway. This could also include development of expert systems that capture the expertise of experienced project planners, and that can intelligently operate and optimize small hydro facilities and generate some of the constraints for use in other optimization models.

The development and implementation strategy of STOM can be summarized in the following points.

1. Divide the project into manageable pieces to reduce the risk of producing a massive system that does not work and to allow the user to test and verify the model and the developer to debug and modify it.
   - Use prototypes to allow ideas and concepts to develop and to test gradually, then incorporate results of prototypes into a full-fledged version.
   - Use an evolutionary approach: develop and release working versions.
   - Develop a series of tools and spin-offs from the system. For example, modules from STOM were adapted for other purposes (e.g., capacity calculation, generation production curves, etc).
2. Keep the solution and its explanation as simple as possible.
   - Use simple explanations of the model and its outputs. For example, the graphical solution of linear programs was used extensively to demonstrate how STOM solved the optimization problem.
   - Hide complexity. Get the user to know what the model is doing in a simple way. For example, after running several studies, some of the users suggested a comparison with optimization to maximize efficiency of one plant in isolation, then two plants combined, then three plants, then the system. Beyond three plants difficulties were encountered.
   - Avoid the concept of "black box" by showing the user the influence of the input data that they control on the output of the model.
3. Develop a satisfactory support base and "market" the system.
   - Obtain user participation in developing and implementing the system.
   - Obtain user commitment. Show the benefits of the system for the user and for the organization.

- Obtain management support. For funding and continuation of project and for forcing reluctant users to use the system.
- Sell the system. Give lots of demos to lots of people in the organization. Try to show-off the quality of the solution as compared to actual and planned schedules.
- Get the user to demonstrate the system to management and to visitors form outside the organization (e.g., a demo to the Bonneville Power Administration and the Corp of Engineers prompted their interests in developing a system similar to STOM).
- Find a number of champion users of the system and get them to adopt it and contribute to its development.
- Do not force new ideas until you convince management and show them its benefits (i.e., do not tell them how to model the system, develop new ideas with them).
- Stress that the user has the final choice to accept and modify or reject results.
- Avoid change and enhance operation of existing systems. Instead of developing a system to replace the LRB system, STOM is looked at by the users as a tool that is integrated within the LRB system.

4. Meet user needs and institutionalize the system.
   - Provide ongoing training.
   - Provide ongoing assistance to explain the results and interpretation of the solution.
   - Get management to insist on mandatory use of the system to arrive at decisions. STOM is considered as a medium for integration and coordination of long and short term planning activities.
   - Beware of the difficulty of forcing people to think in a particular mold. Permit voluntary use to avoid building resistance and the need for a hard sell.
5. Stage the process of system development and evaluation.
   - Develop prototypes and evaluate them.
   - Develop initial designs and evaluate them.
   - Implement initial designs, revise and evaluate them.
6. Be patient and persistent.
   - Do not be discouraged by drawbacks.
   - Do not be discouraged by unfriendly users.
   - Seek excellence and enjoy the development and implementation process.

CHAPTER 6
RESULTS AND DISCUSSION

This chapter discusses the results of developing and implementing the decision support system. It starts with presenting illustrative results from running the system during the prototype and initial design phases of development. Then a summary of the results from a "postmortem" analysis with the four major plants in the B.C. Hydro system for the "Maximize Efficiency" objective function is presented. This is followed by a comparison of the system performance for the "Minimize the Cost of Water Used" and "Maximize the Value of Energy Production" objective functions. Results of the implementation phase for Maximize the Profits objective function are then presented. Next a brief presentation of sensitivity analysis output data for the Maximize Profit objective function is given. Finally the performance of the solution process and the solution algorithm adopted in this study is discussed. This format for presenting results is intended to give an appreciation of how the system evolved during its various stages of development.

6.1 RESULTS OF INITIAL STAGES OF DEVELOPMENT

This section presents results of the prototype and design versions of the optimization model. The behavior of the linear and the piecewise linear models are compared, with emphasis on the behavior of the generation schedules, reservoir operations and optimal plant loading.

6.1.1 Results of the Prototype and Design Phases

As discussed in Section 5.2, the prototype phase involved developing the linear optimization model and demonstrating to the system operations engineers the potential benefits of optimizing the generation and reservoir operations. The linear model was developed using the Excel 5.0 built-in Linear Solver, while the design phase involved developing the first prototype of the piecewise linear model. B.C. Hydro's operations engineers selected the four major plants (G.M. Shrum, Peace Canyon, Mica and Revelstoke) for the prototype and design models. The linear optimization model was very simplified, so that it could be easily modeled and solved using Excel's built-in Solver, while the piecewise linear model required the use of the AMPL and the CPLEX software systems.

The configuration of the optimization models is described in Section 4.5, and illustrated in Figure 6.1. *QI* represents inflows, *QT* and *QS* represent turbine and spill outflows respectively, *G* represents generation and *S* represents storage. The studies were carried out for 24 hours with a one hour interval.

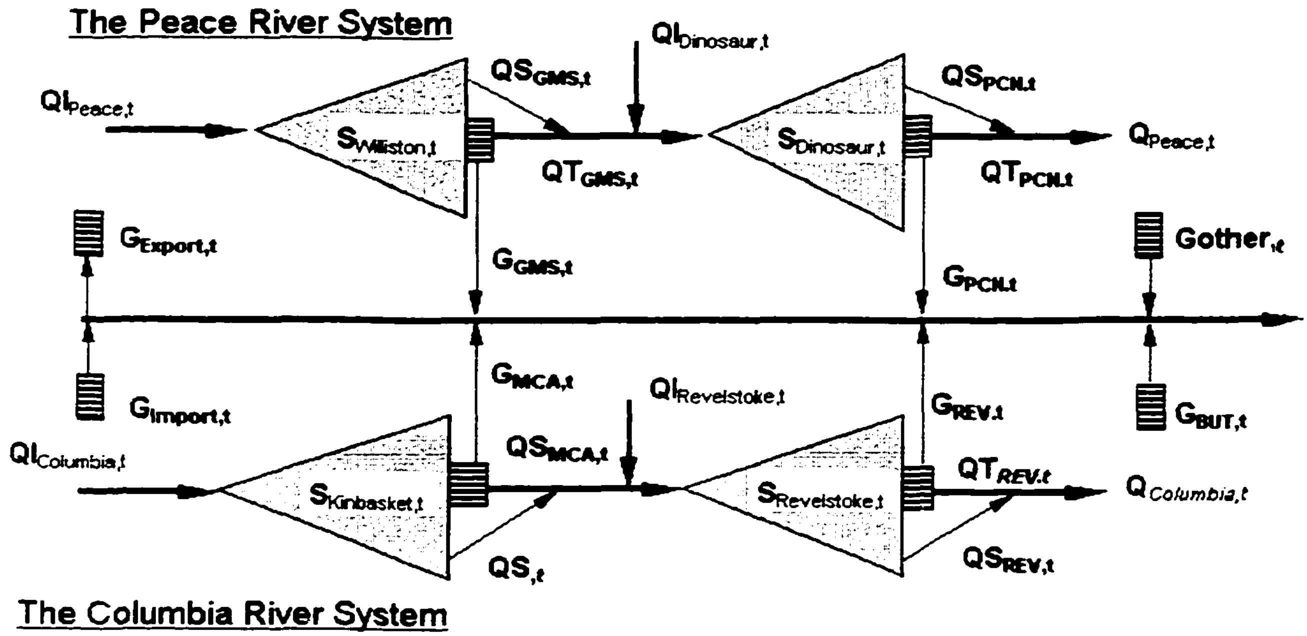


Figure 6.1 Schematic of the Peace and Columbia Prototype Model.

The prototype and design models served the purpose of convincing operations engineers of the benefits of optimizing a system of reservoirs and generating stations (rather than optimizing individual plant and reservoir operations). The prototype model was linear (i.e., linear generation production function) and its results were optimistic (i.e., the model promised more benefits than could be realized). These optimistic results were confirmed when the model in the design phase was completed. The linear model assumed that production efficiency was constant over all generation ranges in each plant -an assumption that could be acceptable in long-term studies but not for hourly operational planning studies. In long-term studies (weekly or monthly plans) the operator is concerned with the average generation of a plant and the studies determines the energy budget in each time step of the plan. In short-term studies, however, the planned generation schedule determines the actual plant loading for each time step in the study.

To illustrate the benefits of using the piecewise linear (PWL) description of the generation production function over a linear function and the effects of using piecewise linear descriptions on generation and reservoir schedules, results from running two of STOM's objective functions will be used: Maximize Efficiency and Maximize the Value of Production.

i. Results of the Maximize Efficiency Optimization Model

The results of the linear and PWL models for the Maximize Efficiency objective function, along with the scheduled generation plan (prepared for this study by the system operations engineers to represent a high domestic load study case) are listed in Tables 6.1 and 6.2. It should be noted that this plan was one of the schedules that were actually prepared during the design phase and before the optimisation model was introduced to operations engineers at B.C. Hydro.

Table 6.1. Planned and Optimised Generation Schedules for the Columbia River System: Mica (MCA) and Revelstoke (REV), in MWHr

Hour	MCA			REV		
	PWL	Linear	Scheduled	PWL	Linear	Scheduled
1	1618	1819	1163	1226	2000	975
2	1618	1819	1027	962	2000	844
3	1618	1819	977	860	2000	791
4	1618	1819	853	681	2000	685
5	1618	1819	841	701	2000	670
6	1618	1819	871	731	2000	715
7	1618	1819	1110	1302	2000	876
8	1819	1819	1710	1652	2000	1572
9	1819	1819	1735	1879	2000	1776
10	1818	1819	1735	1885	2000	1783
11	1818	1818	1735	1792	2000	1691
12	1818	1818	1688	1652	2000	1583
13	1818	1818	1735	2000	2000	1903
14	1818	1818	1681	1651	2000	1565
15	1818	1818	1673	1651	2000	1556
16	1818	1113	1735	1651	2000	1640
17	1818	1028	1735	1651	2000	1646
18	1818	1192	1735	1793	2000	1808
19	1818	961	1724	1651	2000	1586
20	1818	1144	1735	1740	2000	1756
21	1818	1381	1735	1975	2000	1991
22	1818	1072	1735	1669	2000	1905
23	1818	813	1670	1651	2000	1532
24	1712	2118	1497	1651	207	1164
Total	42,129	38,099	35,835	36,058	46,207	34,013

Table 6.2. Optimised and Planned Generation Schedules for the Peace River System: G. M. Shrum (GMS) and Peace Canyon (PCN), in MWHr

Hour	GMS			PCN		
	PWL	Linear	Scheduled	PWL	Linear	Scheduled
1	1663	479	2410	490	700	450
2	1663	517	2410	488	396	450
3	1663	649	2410	487	160	450
4	1663	470	2410	486	160	500
5	1663	489	2410	485	160	546
6	1663	518	2410	484	159	500
7	1663	1088	2410	483	160	670
8	2407	2384	2410	485	160	670
9	2407	2613	2410	486	160	670
10	2407	2620	2410	487	160	670
11	2407	2267	2410	489	421	670
12	2391	2018	2410	490	515	670
13	2407	2325	2410	493	575	670
14	2364	2000	2410	493	508	670
15	2346	1985	2410	494	506	670
16	2407	2736	2410	578	606	670
17	2407	2736	2410	584	697	670
18	2407	2736	2410	605	695	670
19	2407	2736	2410	514	693	670
20	2407	2736	2410	606	691	670
21	2407	2736	2410	606	689	670
22	2407	2736	2410	606	692	450
23	2097	2554	2410	496	695	450
24	1663	2736	2410	495	460	450
Total	51,387	46,862	57,840	12,410	10,816	14,296

The performance of the Maximize Efficiency optimization model is measured by the sum of additional energy gained and stored in reservoirs. The gain is determined by calculating the difference between total energy use by the pre-scheduled plan and the optimized plan. The energy use is calculated by multiplying the hourly turbine discharges for both schedules by the energy conversion factor (HK) for each plant. The value of HK is constant for each plant, and is determined by calculating the energy conversion factor, using the forebay level in the last time step in the study.

Figure 6.2 illustrates the sum of energy use by running the linear and the PWL models and by the scheduled plan for the Maximize Efficiency objective function. The Figure shows that linear models overestimate the benefits of optimization, and that the PWL model yields slight improvement over the scheduled plan. The PWL model, however, produces a more operationally practical plan, as discussed below.

Figure 6.3 illustrates the generation summary of the linear and PWL models and the scheduled plan. It could be noted that both the linear and the PWL models generated more energy from the, more efficient, Columbia River system. Figures 6.4 and 6.5 illustrate the variation in generation and reservoir levels for the four plants in the study. It can be seen that the reservoir levels determined by the linear model fluctuate more than the PWL model. The PWL model cycled the reservoir's forebay levels and loaded plants at different generation levels. In general, cycling of small reservoirs, located downstream of large generating plants, allows the upstream generating plants to be loaded at different generation levels during peak and off-peak hours. Upon explaining the logic behind this behavior, the operations engineers agreed with the optimization model that lowering downstream, small, reservoirs a few hours before the morning and evening peak-load periods produces more efficient operation of the system. They indicated that this behavior also leaves more room for operational

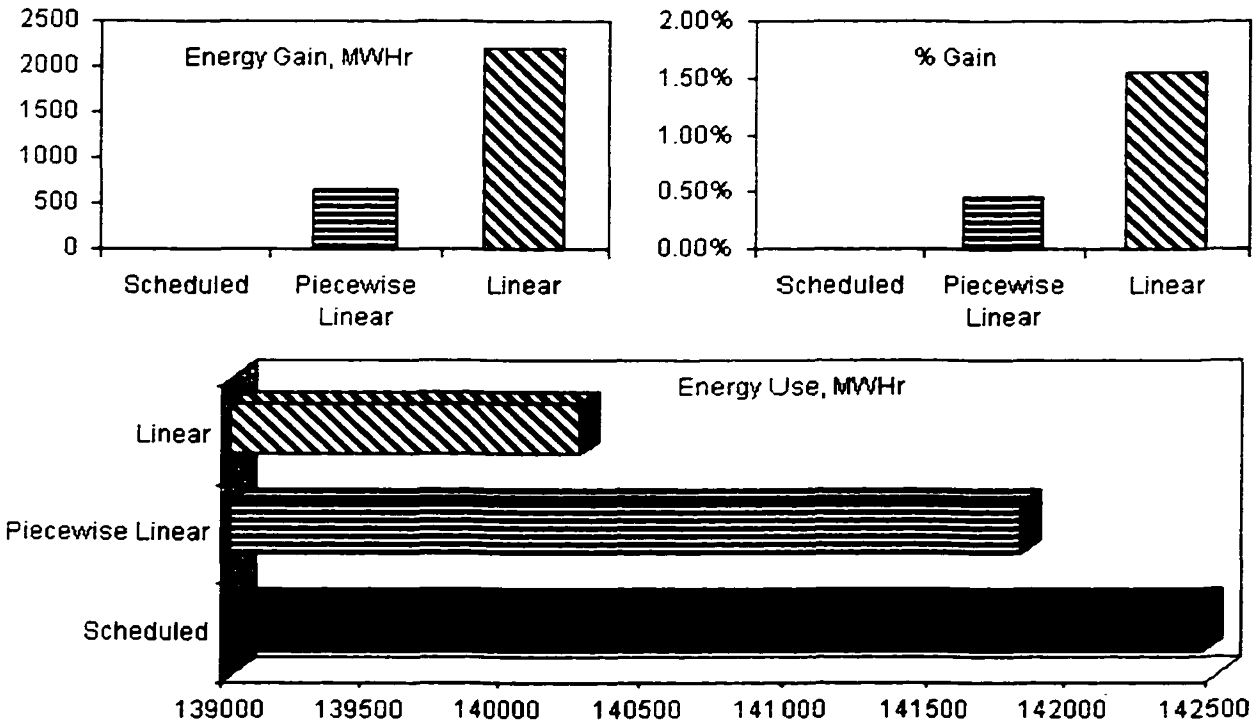
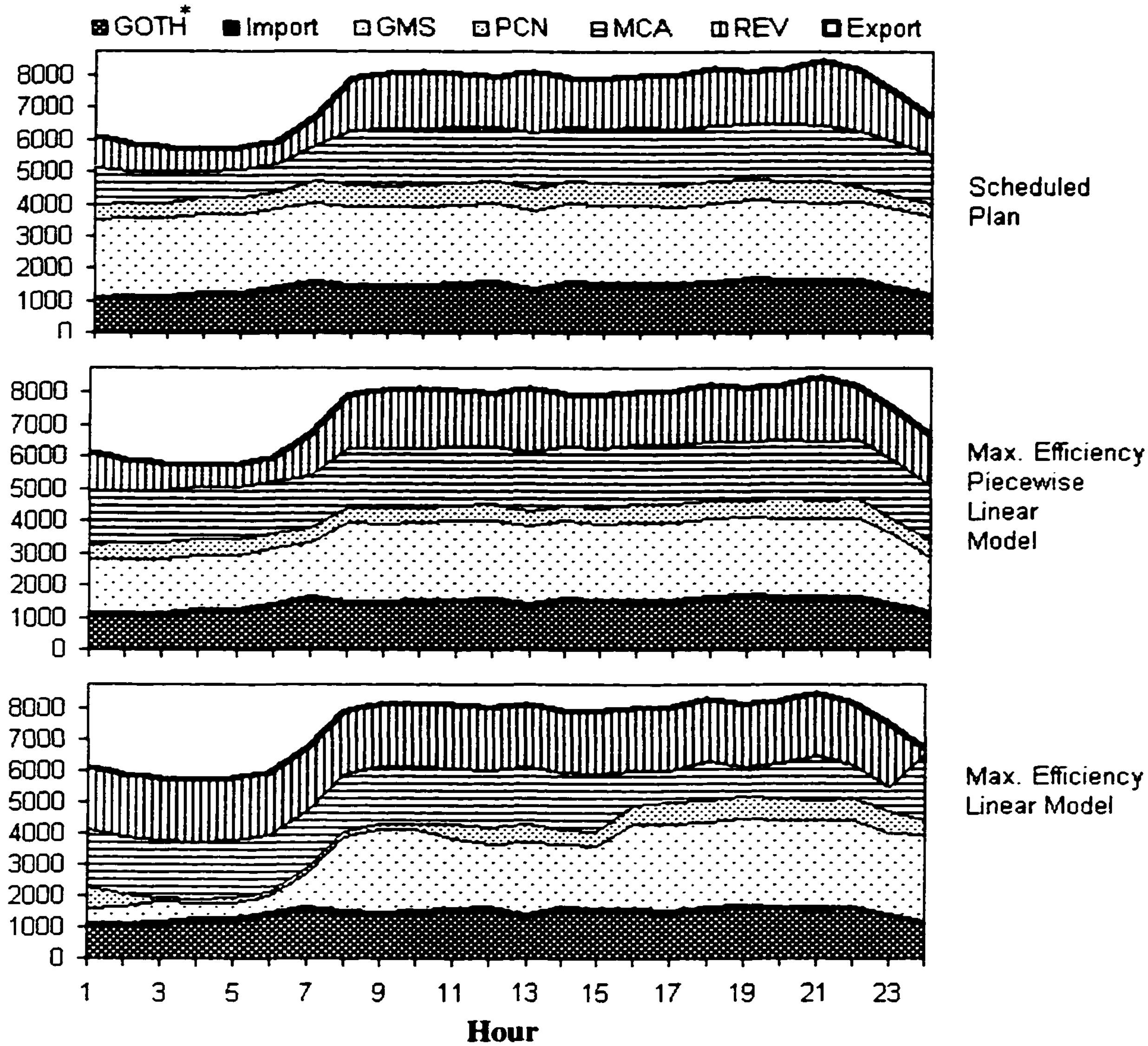


Figure 6.2. Energy Use and Gain for the Max. Efficiency Objective Function: Linear, Piecewise Linear Optimization Models and the Scheduled Plan.

contingencies (e.g. unexpected large fluctuation in domestic load). In addition, lowering smaller reservoir water levels during off-peak hours results in lower losses (due to lower generation levels), while raising the forebay level just before peaks load hours results in head gain and consequently more efficient operation during heavy load hours. The behavior of the optimization model (to cycle small reservoirs situated downstream of large generating plants) has caused a change in the way the system operations engineers now operate the system. In addition to operating plants in an optimal way, this behavior has also been found by the operations group to be operationally more robust.

It can be noted from Figure 6.5 that the PWL model loaded plants at more constant generation levels than the linear model. The constant generation levels are attributed to the breakpoints in the PWL functions, which correspond to peak efficiency points in the generation production function. The behavior of the PWL model, then, has worked as designed, and as expected. The system operations engineers have verified this feature to be operationally practical, since it generally calls for fewer fluctuations in generation levels except for one or two plants. As can be seen in Figure 6.5, REV assumed the function of regulating the system for most hours (hours 1-3, 6-14). This feature of the PWL model has caused some debate during early stages of STOM implementation. However, the debate was settled once a full and detailed analysis was carried out to verify the cause of this behavior, which was attributed to assumption of optimal unit commitment and the methodology for deriving the PWL functions, as discussed in Section 4.5.



* GOTH: Generation from other plants in the B.C. Hydro System.

Figure 6.3. Generation Summary (in MWHr) for Max. Efficiency Objective Function: Linear, Piecewise Linear Optimization Models and the Scheduled Plan.

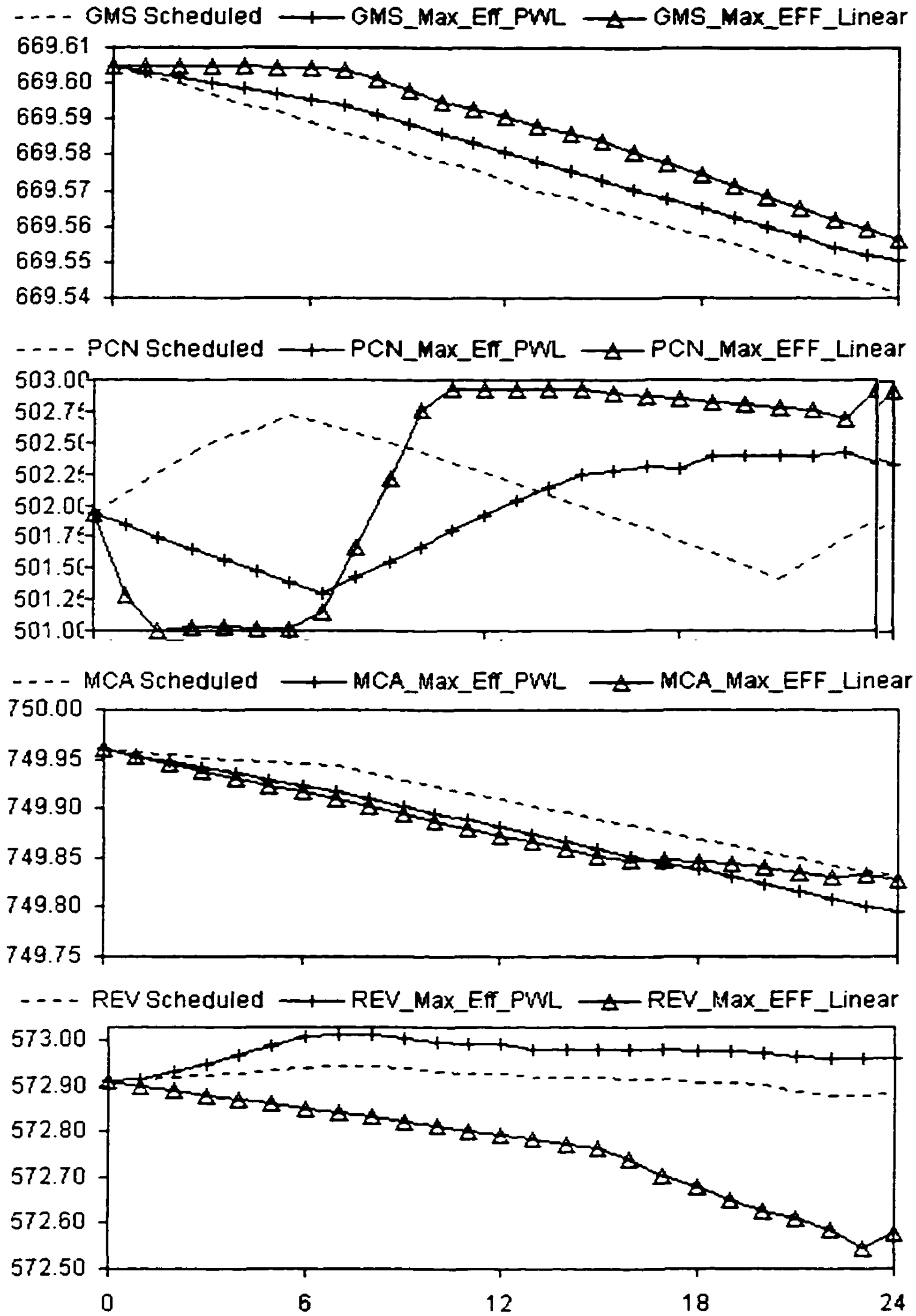


Figure 6.4. Variation of Forebay Levels (in m) for the Max. Efficiency Objective Function: Linear and Piecewise Linear Optimization Models and the Scheduled Plan.

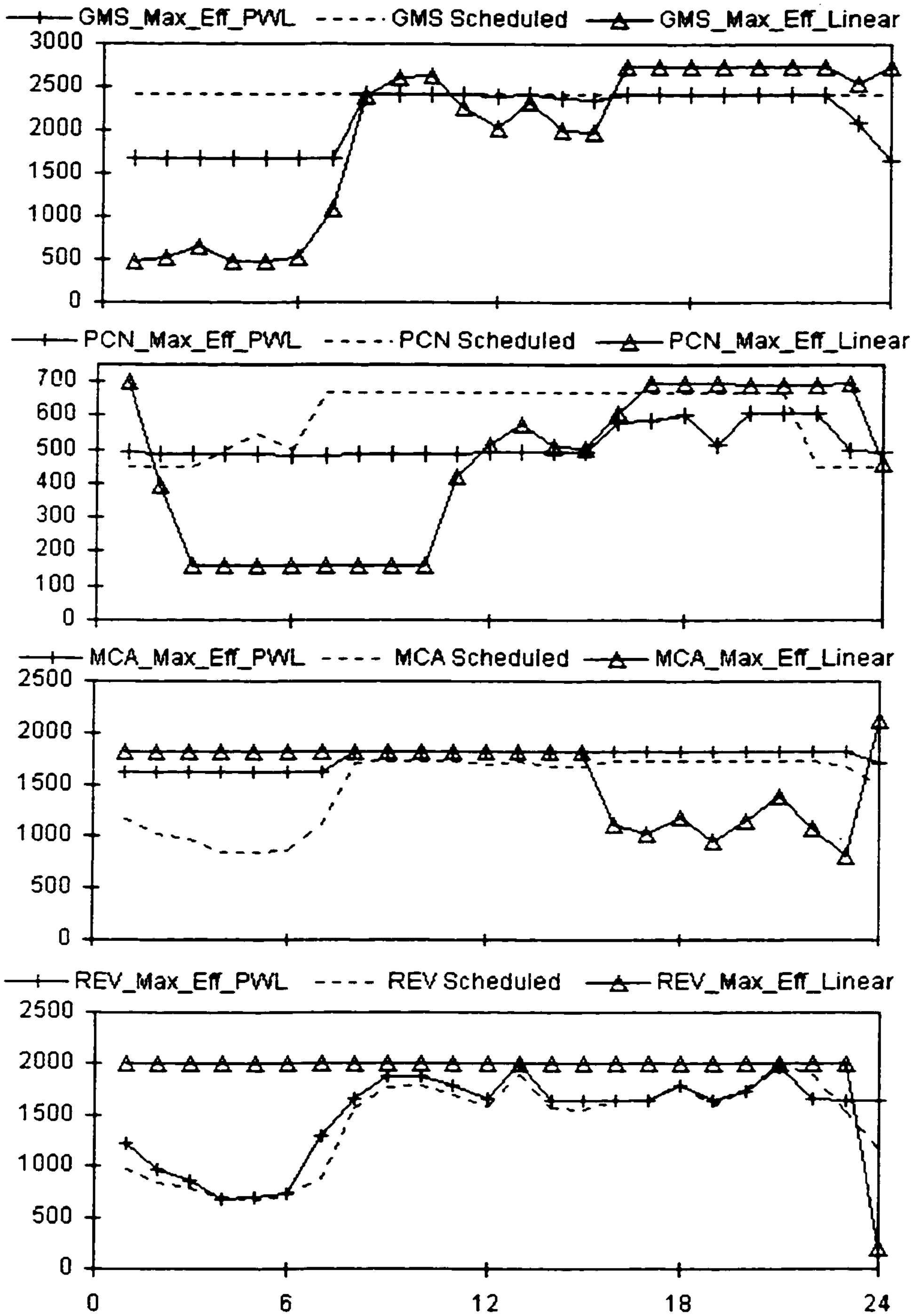


Figure 6.5. Variation of Generation Levels (in MWHr) for the Max. Efficiency Objective Function: Linear and Piecewise Linear Optimization Models and the Scheduled Plan.

ii. Results of the Maximize Value of Production Optimization Model

This objective function maximizes the value of additional energy that could be generated and sold in the spot market, provided that target reservoir levels at the end of the study are met. The target reservoir levels are determined by simulating the effect of the scheduled plan. This study used the same input data as in (i) above. The results of the prototype and the PWL models for the Maximize Production objective function, along with the generation plan are listed in Tables 6.3 and 6.4.

Table 6.3. Planned and Optimized Generation Schedules for the Columbia River System: Mica (MCA) and Revelstoke (REV), in MWHr

Hour	MCA			REV		
	PWL	Linear	Scheduled	PWL	Linear	Scheduled
1	1350	1819	1163	642	284	975
2	1083	1819	1027	642	1489	844
3	980	1819	977	642	207	791
4	824	174	853	642	838	685
5	928	174	841	642	2000	670
6	648	1819	871	951	207	715
7	1118	621	1110	1120	1009	876
8	1705	1819	1710	1651	1107	1572
9	1819	1155	1735	1674	2000	1776
10	1819	1162	1735	1683	2000	1783
11	1818	1070	1735	1651	2000	1691
12	1696	915	1688	1651	2000	1583
13	1818	1818	1735	1896	1497	1903
14	1671	1818	1681	1651	1072	1565
15	1655	1818	1673	1651	1055	1556
16	1801	1818	1735	1651	1741	1640
17	1807	1818	1735	1651	1210	1646
18	1818	1818	1735	1801	1374	1808
19	1736	1818	1724	1651	2000	1586
20	1818	1818	1735	1750	2000	1756
21	1818	1818	1735	1857	2000	1991
22	1818	1818	1735	1651	2000	1905
23	1406	1818	1670	1650	2000	1532
24	866	2118	1497	1650	207	1164
Total	35,817	36,481	35,835	34,099	33,296	34,013

Table 6.4. Optimized and Planned Generation Schedules for the Peace River System: G. M. Shrum (GMS) and Peace Canyon (PCN), in MWHr

Hour	GMS			PCN		
	PWL	Linear	Scheduled	PWL	Linear	Scheduled
1	2408	2736	2410	599	160	450
2	2408	724	2410	599	700	450
3	2407	2443	2410	599	159	450
4	2407	2736	2410	575	700	500
5	2407	2134	2410	490	159	546
6	2407	1771	2410	490	700	500
7	2407	2736	2410	490	700	670
8	2407	2736	2410	599	700	670
9	2407	2736	2410	691	700	670
10	2407	2736	2410	689	700	670
11	2407	2736	2410	630	700	670
12	2407	2736	2410	597	700	670
13	2407	2736	2410	597	666	670
14	2407	2736	2410	597	700	670
15	2407	2736	2410	597	700	670
16	2407	2736	2410	597	160	670
17	2407	2736	2410	597	697	670
18	2407	2736	2410	597	695	670
19	2407	2173	2410	597	693	670
20	2407	2062	2410	597	691	670
21	2470	2299	2410	661	689	670
22	2407	1990	2410	625	692	450
23	2407	1549	2410	599	695	450
24	2407	2736	2410	599	460	450
Total	57,833	58,185	57,840	14,303	14,317	14,296

The performance of the Maximize the Value of Production objective function is measured by the sum of the value of additional energy generated and sold in the spot market. This is to say that using this objective function the extra energy generated can be sold at the spot market. The distribution of additional energy is influenced by the hourly spot market price, as discussed in Section 4.5.

Figure 6.6 illustrates the value of production by the prototype linear and the design models and by the scheduled plan for the Maximize the Value of Production objective function. The Figure clearly shows that linear models overestimate the benefits of optimization, and that the PWL model yields marginal improvement over the scheduled plan. The PWL model, however, produces a more operationally practical plan, as discussed below.

Figure 6.7.a illustrates the generation summary of the linear and PWL models and the scheduled plan. It can be noted that the linear model generated more from MCA and GMS (the most efficient), and less from REV, with very slight change in PCN generation schedule (see Figure 6.7.b). Figures 6.8 and 6.9 illustrate the variation of reservoir and generation levels for the four plants in the study. The reservoir levels and generation schedules derived by the linear model fluctuates more violently than the PWL model and the scheduled plans,

while the PWL model deviated slightly from the planned forebay levels and planned generation schedules. In general, the linear model results in considerable variation in generation at individual plants, which is unacceptable to system operations engineers. This could, perhaps, explain the mistrust of operators for purely linear optimization models.

The Maximize the Value of Production objective function could serve purposes other than deriving the optimal generation and reservoir schedules, given fixed target reservoir levels and spot market prices. Sensitivity analysis data derived from this model provides the user with the hourly system incremental cost, the plant incremental cost, and the marginal value of water stored in each reservoir. The system incremental cost is the shadow price of the load-resource balance equation, and it represents the cost of increasing the system load by 1 MWHr. The plant incremental cost is the shadow price of the PWL generation production function, and it represents the cost of increasing generation by 1 MWHr. The hourly marginal value of water is the shadow price of the mass balance equation, which represents the value of increasing storage in a reservoir by 1 cubic meter. The shadow price of other constraints in the optimization model could be used to derive the costs or benefits of tightening or relaxing the bounds of constraints. For instance, the shadow price of the generation limit constraints could be used to value the next increment in generation capacity, when the constraint is binding. For more discussion on sensitivity analysis information and its significance to operations planning see Section 6.2.5.

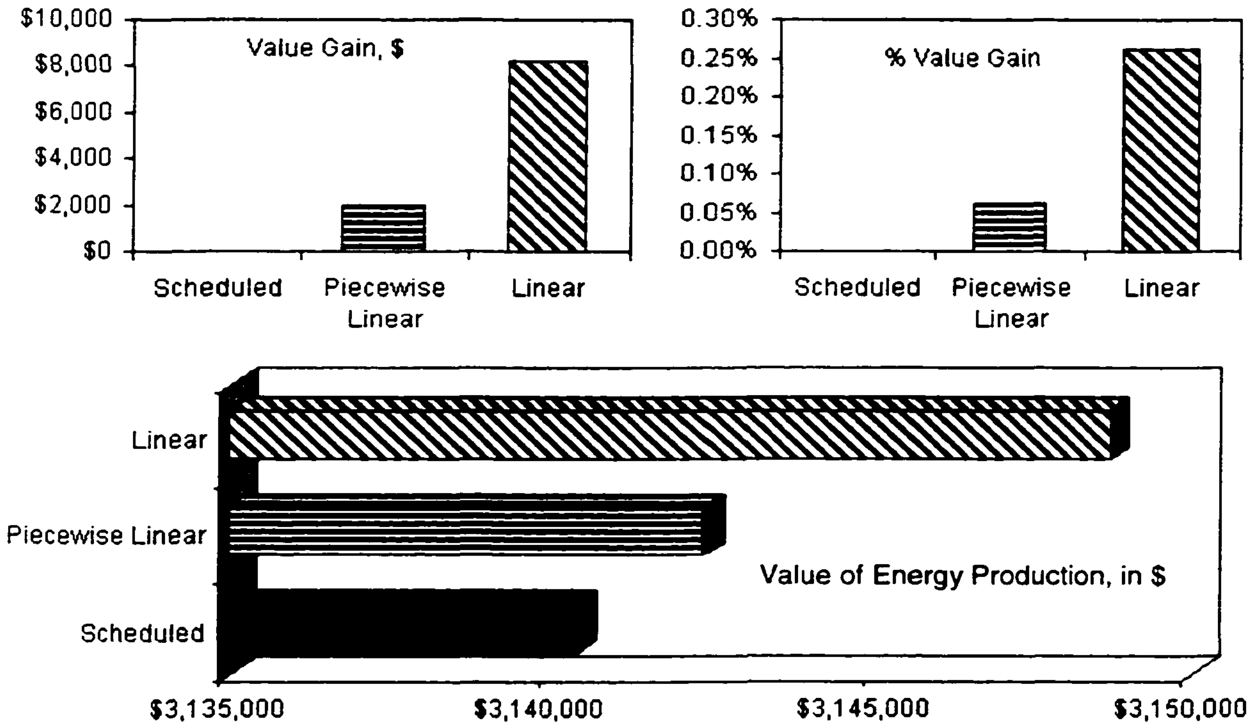


Figure 6.6. Production Gain for the Max. Production Objective Function: Linear and Piecewise Linear Optimization Models and the Scheduled Plan.

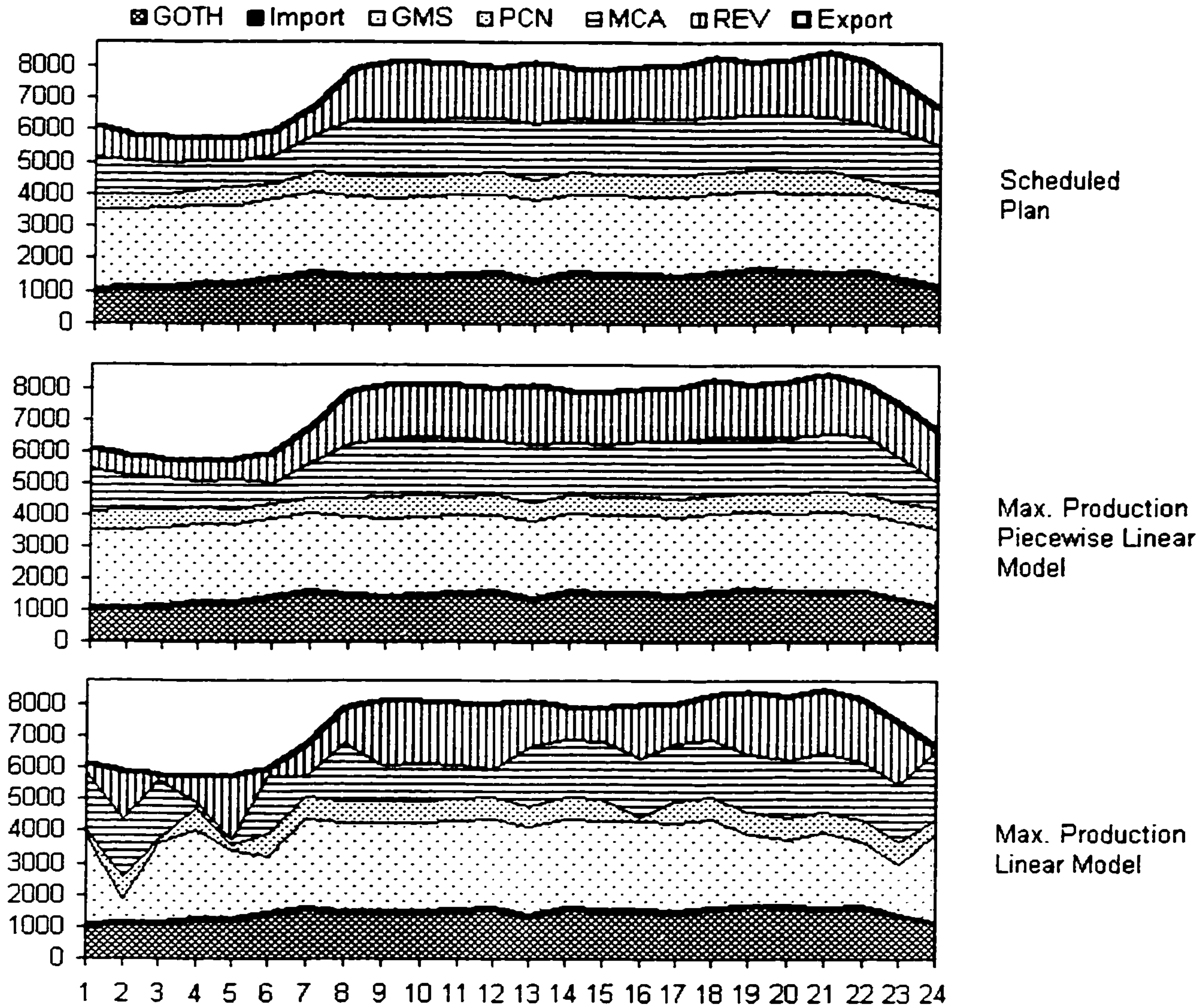


Figure 6.7.a. Generation Summary (in MWHr) for Max. Production Objective Function: Linear, Piecewise Linear Optimization Models and the Scheduled Plan.

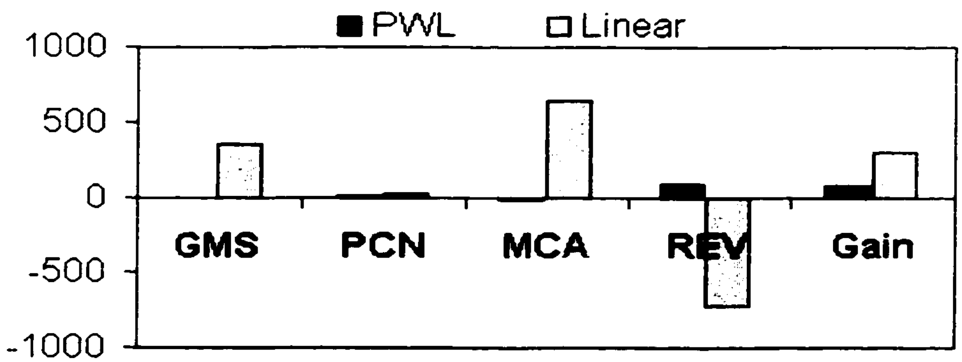


Figure 6.7.b. Gainers and Loser in Generation, and Production Gain of the Linear and Piecewise Linear Models, in MWHr.

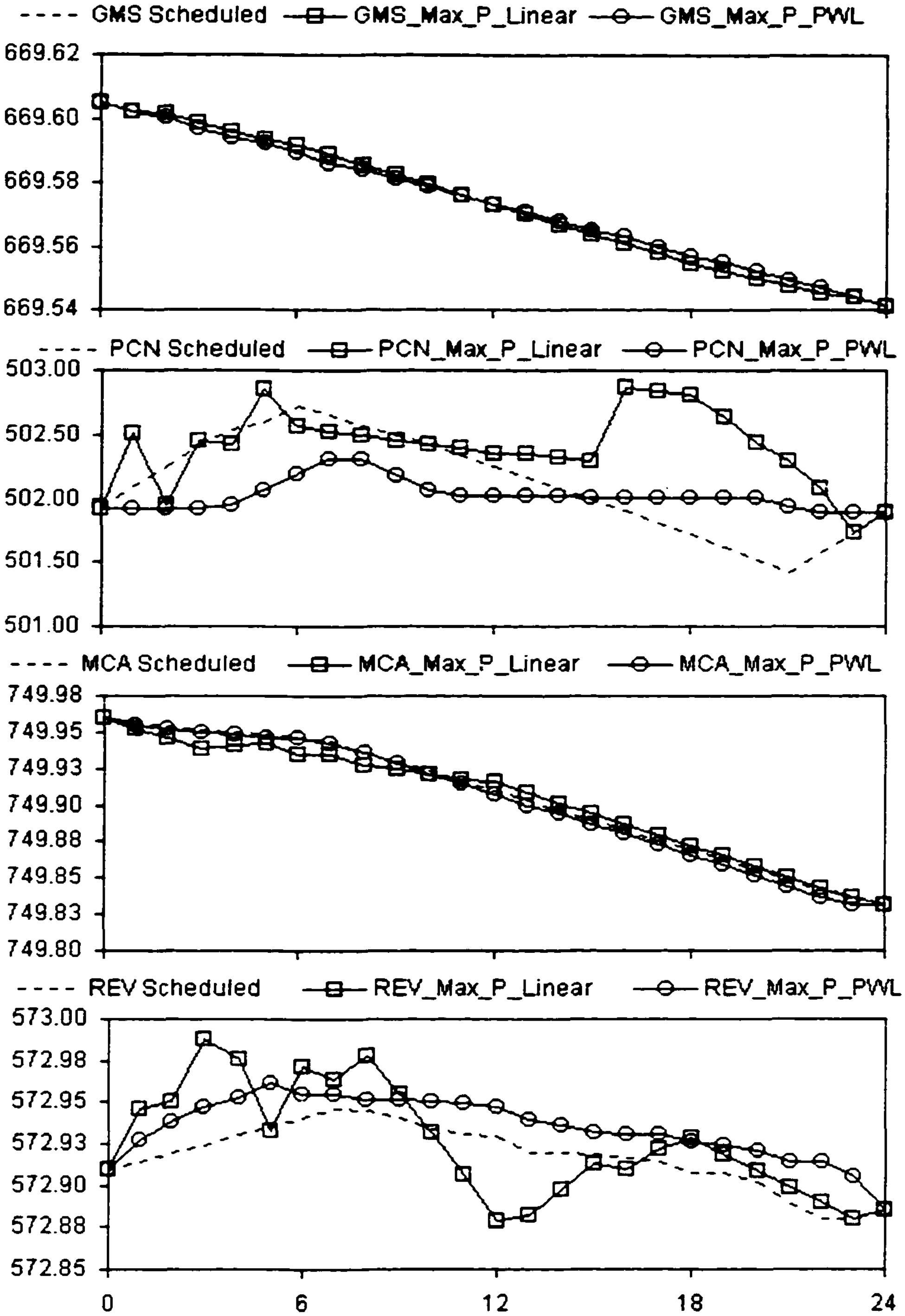


Figure 6.8. Variation of Forebay Levels (in m) for the Max. Production Objective Function: Linear and Piecewise Linear Optimization Models and the Scheduled Plan.

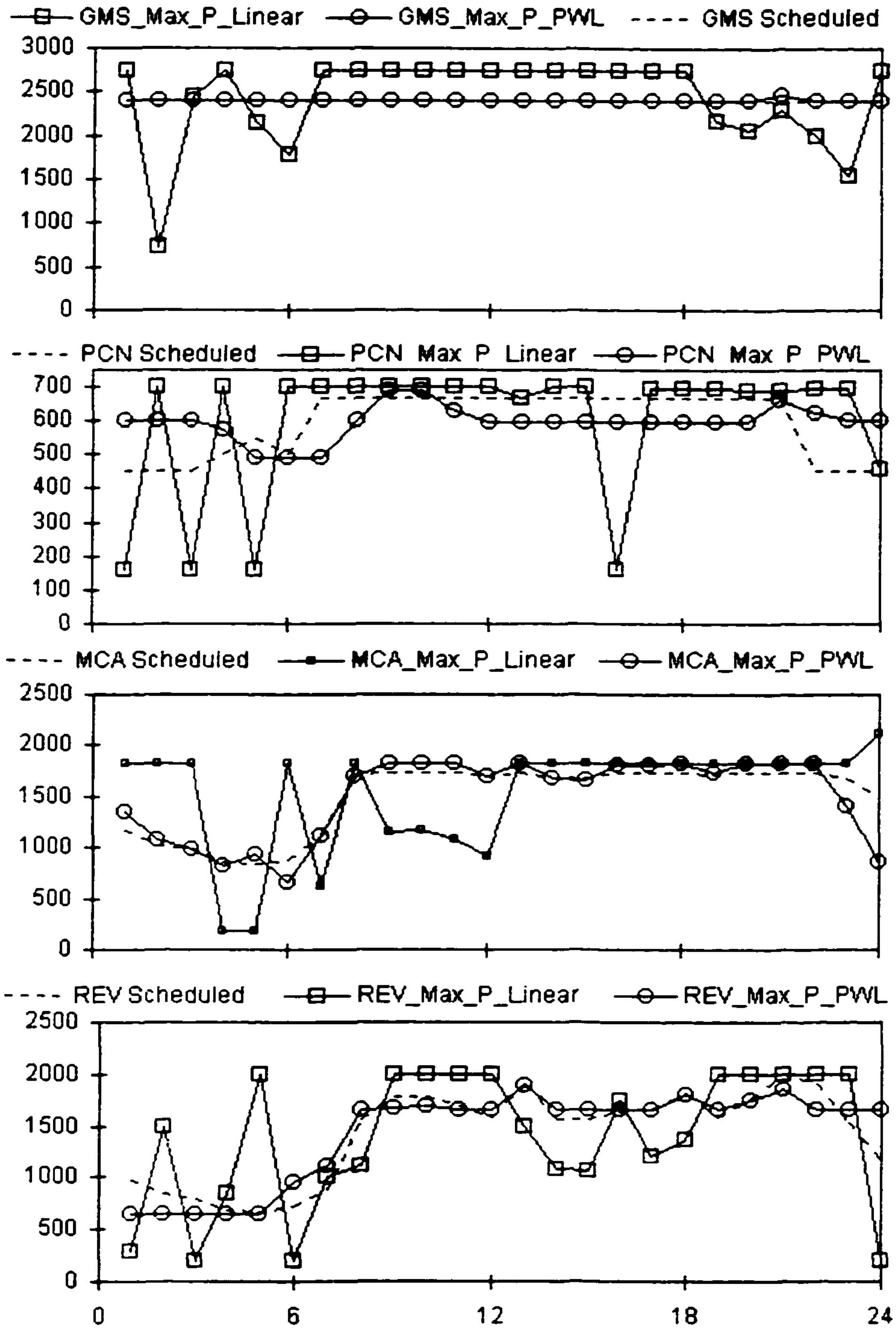


Figure 6.9. Variation of Generation (in MWHr) Levels for the Max. Production Objective Function: Linear and Piecewise Linear Optimization Models and the Scheduled Plan.

6.1.2 Discussion on the Prototype and Design Phase

The prototype linear model served the purpose of illustrating the benefits of using optimization models to aid system operations engineers in determining the hourly generation and reservoir schedules. The results of the initial development phase, however, clearly indicated that linear models are of little value for real-time system operations activities. For this reason more elaborate modeling of the generation production function was needed, and the piecewise linear functions proved to be the most appropriate one to adopt (see Section 4.5 for more details).

As indicated in the results presented above, the PWL function performed as designed and as expected. Close examination of the behavior of optimized generation schedules revealed other important properties that are of significance to real-time system operations. The results showed that in many instances one or two plants could operate away from peak efficiency points. The practical interpretation of this behavior is what is called in the industry as 'swing plants'. Swing plants are used to perform system regulation and control. In real-time control of generating facilities, one or two, high capacity, plants are usually assigned the duty of system regulation (basically to follow the system load and to regulate the electric system frequency). These plants are equipped with automatic generation control (AGC) devices, which basically sense the discrepancy between system load and system generation and automatically adjust generation levels of the AGC plants to meet system load. One of the main functions of the real-time generation system operator is to schedule generating plants for the next few hours (see Section 3.2 for details). Every hour, the Shift Engineer send the system control center what is known in the industry as 'Base Points'. Base points consist of the hourly generation schedule for each plant, and the preference of the generation system operator on which plants are supposed to regulate the system in real-time. The use of the PWL linear formulation, to describe the generation production functions, has allowed STOM optimization models to derive the optimal generation schedules *and* the optimal assignment of the regulating plants for each hour in the study.

Figure 6.10 and 6.11 illustrates results of running STOM for the Maximize Efficiency objective function for the four major plants in the BC Hydro system (GMS, PCN, MCA and REV) for 168 hours. A '1' indicates that the corresponding plant generation is exactly at one of the breakpoints of the PWL function (i.e. at one of the peak efficiency points), while '0' indicates that the plant is regulating, or taking the slack generation to meet system load. On average (for this study), MCA assumed the function of regulation (since the percentage of optimal loading averaged 63%), while the least efficient plant among the four (PCN) was loaded at peak efficiency levels most of the time (average of 81%). GMS and REV optimal loading averaged 71% and 72% respectively. It could also be noted that MCA assumed the main regulation function for most morning hours in weekdays. This is due to two main reasons: minimum generation limits, and efficiency of the plant at low generation levels. The MCA and REV plants have the capability to generate more efficiently at low generation levels during low load hours. MCA and REV are also capable of shutting down completely during low load hours, while GMS and PCN are required to operate continuously to satisfy minimum flow requirements. In addition, and since the reservoir feeding PCN is small, and it rapidly responds to inflows from GMS, PCN generation levels are also pinned at peak efficiency points during low load hours, except when it is more efficient to operate it as a regulating plant alongside MCA and REV to keep GMS at peak efficiency (e.g. during Sunday morning hours).

Figure 6.12 compares the efficiency indices and PWL generation production functions for the four plants in hour 18 of the study. For each plant, the efficiency index is calculated by indexing the production efficiency of the four breakpoints to the production efficiency of third point in the PWL functions. For each hour in the study, the linear programming algorithm determined the optimal generation schedule for the four plants in the following way. The algorithm searches the vertices of the space bounded by the PWL functions and other binding constraints (e.g., the load resource balance equation). If constraints other than the PWL function are not binding, then the algorithm finds the solution at the breakpoint of the PWL functions. If the total required generation from the four plants in the study happens to coincide with any of the breakpoints of the four PWL functions, and all other constraints are satisfied, then the algorithm would load each plant at the most efficient breakpoints (see for example Wednesday hour 4 in Figure 6.10), otherwise it will search for the plant that yields the least loss in efficiency and assign it the slack. The plant with the least loss in efficiency is determined from the slope of the segments of the PWL function. For example, Figure 6.12 shows the optimal generation schedule for hour 18 in the study, which represents the evening peak-load hour. It can be seen that the loss of the system efficiency would have increased if GMS or PCN generation increased, so increasing their generation would not be optimal. Now if MCA generation was reduced to coincide with the third breakpoint (the most efficient point) and REV generation increased to the fourth point, REV generation could not have satisfied the discrepancy resulting from MCA backing-off from the fourth to the third point (since REV generation is near the maximum generation limit). This means that either GMS or PCN would have to make-up for the slack. Since GMS is the more efficient of the two plants, its generation would have to increase beyond the third breakpoint to meet the load. The drop in efficiency under this scenario, however, will be larger than the optimal allocation determined by the optimization model (note the sharp drop in efficiency in the third segment of the GMS efficiency index), and likewise the generation schedule would not be optimal.

Returning to Figure 6.10, it can be seen that during high-load hours (8 a.m.–9 p.m.), the Peace River system assumes the main function of system regulation for most weekdays in this study. This is due to the fact that at generation levels in the range of the third breakpoint the efficiency of the GMS is much higher than the other three plants. During the weekend, however, GMS is loaded at peak efficiency levels at the second point, and the function of system regulation is handed to MCA. This is due to the fact that at high generation levels the production efficiency of MCA is high and the drop in efficiency at the high end of the efficiency index curve is lower than for the GMS (note the flatness of MCA and REV efficiency index in the vicinity of the third breakpoint, as compared to the sharp decline in efficiency in the Peace system).

Several other factors have been noted to influence the behavior of the optimization model, and whether plants were loaded at peak efficiency levels or not. First, when the domestic load is high, generation levels could increase beyond peak efficiency points to meet the load (e.g., Tuesday hour 18). Second, when reservoir water levels are in the vicinity of their maximum or minimum levels, production efficiency of the plant (or an upstream plant) is sacrificed. Third, when minimum generation limits are binding (due to unusual operational conditions, e.g., the ice formation in the Peace system) production efficiency could be lowered. Fourth, ramp up and ramp-down periods usually require more than one (in some instances three) plant to go through inefficient zones. Studies using the Maximize Profit objective function also indicated that more plants would be operated at lower efficiency levels to meet the regulating and operating reserve requirements and to generate more when market prices are high.

In summary, the design and formulation of STOM's optimization models and the modeling methodology adopted by this thesis have met the operational as well as the technical requirements of the decision support system as outlined by the users' requirements. The features of the piecewise linear functions discussed in this section are very powerful when used in combination with linear programming algorithms to determine the optimal allocation of production facilities. It, however, requires very accurate and careful in-depth study of the production function and its properties.

Plant	Day of Week	Hour 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	% Optimal Loading	% Optimal in Study
GMS	Wednesday	1	1	1	1	1	1	1	1	1	1	1	0	1	0	0	1	1	1	1	1	1	1	0	1	83%	71%
	Thursday	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	50%	
	Friday	1	1	1	1	1	1	1	0	0	0	1	1	1	0	0	0	0	1	1	0	1	0	0	0	54%	
	Saturday	1	1	1	1	1	1	1	1	1	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	92%	
	Sunday	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	1	1	1	92%	
	Monday	1	1	1	1	1	1	1	0	1	1	1	0	1	1	0	0	0	1	0	0	1	1	0	1	67%	
	Tuesday	1	1	1	1	1	1	1	0	1	0	0	0	0	1	1	1	0	0	1	1	0	1	0	0	58%	
PCN	Wednesday	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	0	0	1	0	1	1	1	1	1	83%	81%
	Thursday	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	1	1	0	1	1	88%	
	Friday	1	1	1	1	1	1	1	1	1	1	1	0	0	1	1	1	1	0	0	1	1	1	1	1	83%	
	Saturday	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	88%	
	Sunday	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	71%	
	Monday	1	0	0	0	1	1	1	1	0	1	1	1	0	0	1	1	1	1	1	0	1	0	1	1	67%	
	Tuesday	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	0	1	1	1	0	88%	
MCA	Wednesday	0	0	0	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	71%	63%
	Thursday	0	0	0	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	83%	
	Friday	0	0	1	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	88%	
	Saturday	0	0	1	1	1	1	1	1	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	33%	
	Sunday	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8%	
	Monday	0	1	1	1	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	83%	
	Tuesday	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	71%	
REV	Wednesday	1	1	1	1	1	1	1	0	0	0	0	1	0	1	1	1	1	0	1	0	0	0	1	1	63%	72%
	Thursday	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	1	1	1	79%	
	Friday	1	1	0	0	0	0	1	1	1	1	0	0	1	1	1	1	1	1	1	1	0	1	1	1	71%	
	Saturday	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	75%	
	Sunday	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	96%	
	Monday	1	1	1	1	0	1	1	1	1	0	0	1	1	1	1	1	1	0	1	1	0	1	1	1	79%	
	Tuesday	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	42%	

Figure 6.10. Optimal Loading Pattern: the Effect of Using Piecewise Linear Generation Production Function in STOM.

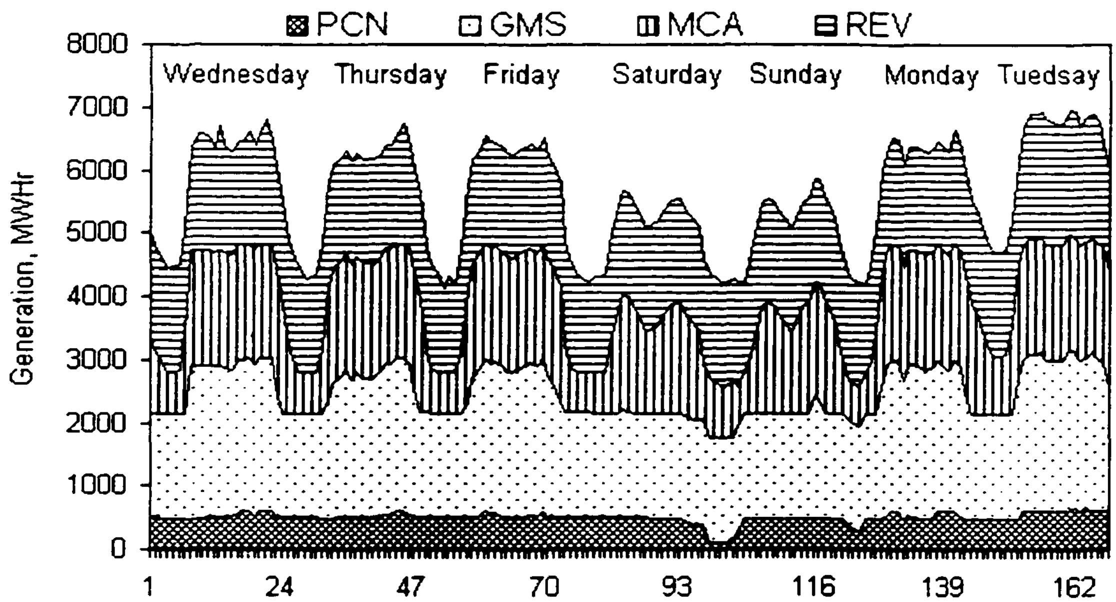


Figure 6.11. Optimal Generation Schedule for GMS, PCN, MCA, and REV.

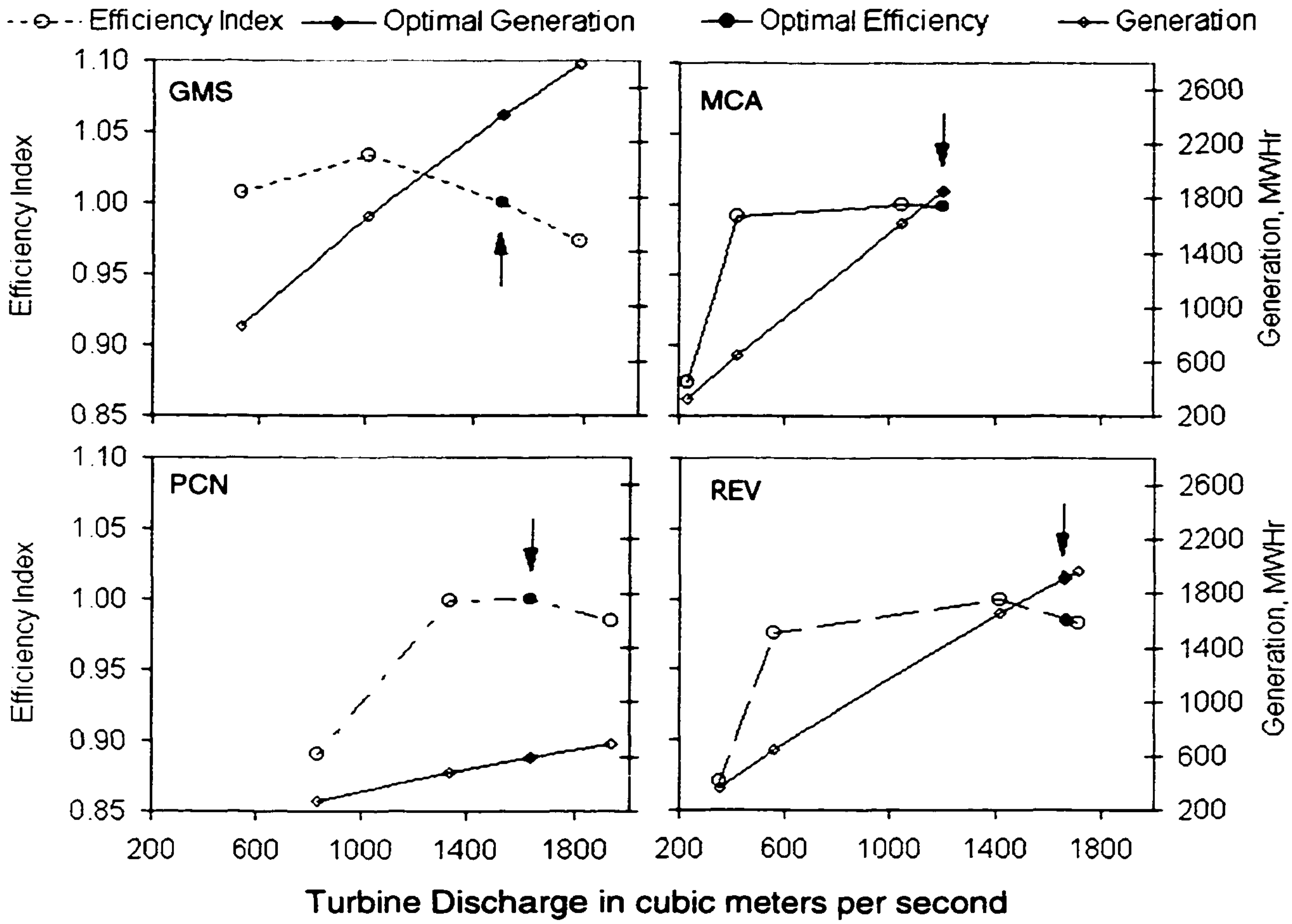


Figure 6.12. Efficiency Index and PWL Production Function (Hour 18 in Study).

6.2 RESULTS OF THE IMPLEMENTATION PHASE

This section presents results of implementing STOM optimization models in training and in production mode. The structure and objectives of the "postmortem" analysis studies are discussed first. Then, results of the postmortem analysis studies are presented. This is followed by presentation of results from running STOM for Maximize Value of Production and for Minimize the Cost of Water Used objective functions. Then results and discussion of the initial implementation of Maximize Profit objective function in production mode are presented.

6.2.1 Structure and Objectives of the Postmortem Analysis Studies

As indicated in Section 5.2, the initial phase of STOM implementation focused on training the shift engineers on the new decision support tool and on testing and assessing STOM benefits for their daily operations. The training and testing sessions were structured so that the shift engineer, who worked on the previous day(s) shift, ran a postmortem study of the schedules dispatched by the real-time system control center. The studies were carried out using Maximize the Efficiency objective function, for the four major plants in the BC Hydro system (G.M. Shrum, Peace Canyon, Mica and Revelstoke) and for 24 hours. Maximize the Efficiency objective function was selected by the Shift Office management for two main reasons. First, it was easy to use in terms of the required input data to run the optimization model. Second, the shift engineers were familiar with the objective of maximizing the efficiency of individual plants in a river system (using plant's efficiency curves), and running this objective function highlighted the benefits of maximizing the efficiency of the whole generating system (rather than individual plants).

6.2.2 Results and Discussion of the Postmortem Analysis Studies

Over the period June 1998 to April 1999, about 50 postmortem analysis studies were carried out. Overall, STOM performed the functions it was designed for, and it met the user's functional requirements, as described in Section 4.2.

Table 6.5 lists the results of the postmortem studies. The first column contains the date of the postmortem analysis study, the second column lists the total generation of the four plants included in the study, the third-sixth lists change from actual scheduled generation for each plant, while the last column lists the percentage gain in stored energy (as defined in Section 6.1). The postmortem studies covered almost a full year, and thus the schedules represented almost all generation patterns that could be encountered in a typical year. For example, the maximum total generation occurred on 22 December 1998. The domestic load was the highest on record (8452 MWHr at 6 p.m.) for B.C. Hydro. The total system generation peaked at 9146 MWHr, and the four plants generated about 72% of total generation. Figure 6.13 illustrates the distribution of generation for the four plants, exports and generation by other plants in the BC Hydro system for hour 18 (no imports were made in this hour). In this day, STOM gained 1.6% (2320 MWHr) over the dispatched schedule.

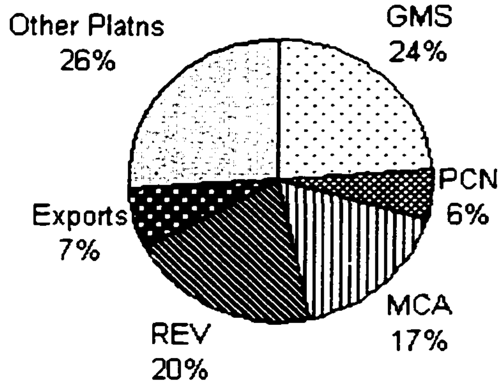


Figure 6.13. Distribution of Generation at Hour 18 on 22 Dec. 1998.

The other example consists of the generation schedule for 21 June 1998. This day marked the lowest hourly generation schedule in record for the four plants (512 MWHr at 6 a.m.). The total system generation was at 4053 MWHr and the four plants generated about 13% of the total. In this case, STOM could not improve over the dispatched schedule and did not score any positive gains, rather it reported a loss of 0.78% (-149 MWHr) over the dispatched schedule. The main reason for this loss was as follows. During the month of June, Mica was operated for what is called 'fish-flush operation.' This mode of operation requires that one unit at the Mica plant operate for 15-20 minutes, two to three times a-day, at its minimum generation level (200 MWHr) to avoid a kill of entrapped fish in the turbine ancillary structure. Since the optimization model operates at hourly time steps, and since the minimum generation level at Mica was set at 200 MWHr, the model was forced to load the Mica plant at the minimum generation limit. Since Mica was forced to generate at this minimum level, other plants had to reduce generation to accommodate the constraint. The optimization model was forced to load other plants (GMS, REV, and PCN) inefficiently, which in turn caused the gain to be negative. In other words, the optimization model did not have any flexibility to maneuver, but the actual system did because it had all the plants, not just the four in the study.

Figures 6.14 and 6.15 present the contents of Table 6.5 graphically. It can be noted that when total generation from the four plants was low (June-July), gain was low, and in some instances negative. However, when total generation increased, gains followed (late August). But when total generation increased above a certain level (above 90,000 MWHr), the gain decreased (early to late Sept., late Oct., late Jan.), although on some days the gain was highest when total generation was high! Figures 6.14 and 6.15 shows that when the allocation of load between the two river systems was evenly distributed, the gain was low. Figure 6.16 indicates that the optimization model distributed generation among the Columbia and the Peace River systems in a proportion close to their relative capacities. This suggests that when the operators scheduled the generation close to this pattern, they were approaching optimal operation –leaving little gain available for STOM.

It can also be noted in Figure 6.14 (top chart) that the optimization model consistently scheduled more generation from the Peace system from late August to November, and then switched to generate more from the Columbia River system from late November up to the end of April. This behavior could also be partially attributed to the uneven allocation in the dispatched schedules among the two river systems during these periods. Figure 6.14 also shows that despite the low domestic load during summer months (July, August and

September) in British Columbia, total generation was relatively high. This can be attributed to heavy exports to the California market.

Figure 6.17 illustrates the variation of percentage of energy gain with total actual generation for the Maximize Efficiency objective function. It can be noted that the gain in stored energy was highest when total generation of the four plants was in the range 75,000-120,000 MWHr. This observation was also confirmed by STOM users, who indicated that the highest gains from optimization models can be realized when the system has some flexibility. By flexibility is meant that when total system generation is neither at its lowest or its highest levels (or near maximum capacity limits). The results of postmortem analysis studies reinforce this view, as shown in Figure 6.17. When the system has some flexibility, then, and as discussed in Section 6.1, the optimization model has more freedom to select the most efficient among the breakpoints of the PWL functions, thus enabling the model to optimally allocate the resources at hand.

Analysis of results presented in Table 6.5 indicated that the expected gain in stored energy was about 1.27%, representing a gain of about 1245 MWHr for a 24-hour period. Evaluated at market price (say about Can$25/MWHr), the monetary value of gain could amount to about CAN$31,000/day, or on annual basis, the total gain in stored energy could amount up to CAN$11.4 million per annum. Even a very conservative estimate of 0.5% gain would yield about CAN$4.48 million, which is in-line with BC Hydro's estimate (CAN$5 million) of the gains that could be obtained from implementing STOM in real-time operation. It should, however, be pointed out that gains from using the optimization model will tend to decrease as its users become accustomed to the optimal operation of the system. This in fact was one of the main benefits from the postmortem analysis studies. Some of the Shift Engineers indicated that running STOM, was not only a "somewhat humbling" experience, but it also gave them the chance to derive some rules-of-thumb that they could use. However, the system operator still need a decision support system, such as STOM, for him/her to be confident that the decision they are about to make is optimal, or near optimal.

Figure 6.18 displays the probabilities and cumulative distribution function (CDF) for percentage of energy gained and stored in reservoirs for the Maximize efficiency objective function. The probability distribution function is skewed to the right -indicative of the tendency of the tail to extend more on the positive side of the distribution.

The set of input data for the postmortem analysis studies was also used to run two of STOM's other objective functions: Minimize the Cost of Water Used and the Maximize the Value of Energy Production. Results of the runs are listed in Table 6.6. These optimization models displayed similar optimized generation schedules to those exhibited by the Maximize Efficiency objective function. The performance measure for the Maximize Value of Energy Production was defined in Section 6.1. The performance measure for the Minimize the Cost of Water Used depends on the units of the coefficients of the objective function, the cost factor, which is a user input as discussed in Section 4.6. For the results presented in this section, the cost factor reflects the marginal value of water stored in reservoirs, in $\$/m^3$ per second. The performance measure for this objective function then represents the monetary value of water gained and stored in reservoirs, which to some extent is similar to the performance measure of the Maximize Efficiency objective function. Figures 6.19 and 6.21 display the variation in value gain with total generation and Figures 6.18 and 6.22 display the probability and cumulative distribution functions of the percentage of gain in value for the two objective functions. It can be noted from these illustrations that the variation in gain with total generation behaved in a similar way to that with the Maximize Efficiency objective function. However, the Maximize Value of Energy Production yielded much lower gains, because reservoir water levels were constrained to meet fixed targets at the end of the study period. Table 6.7 gives a summary of the statistical tests that were carried out on the results for the three objective functions.

It can be seen that gains of the Maximize Efficiency and the Minimize Cost of Water behaved in a similar way, except that the gain in the Minimize the Cost of Water Used tended to be flatter on the positive side. The same, however, cannot be said about the Maximize Value of Energy Production objective function. The dispersion of gain for this objective function is much lower (about 50%) than with other objective functions, which is indicative of the tendency of gain to be more concentrated around the mean (i.e., peaky). In addition, close inspection of Figure 6.21 reveals that the gain was also highest when total generation was high. Figure 6.23 compares the variation of percentage of gain with total generation, and a second-order polynomial function, which was curve-fitted to the results. It can be noted that the gain for the Maximize Efficiency and Minimize the Value of Water Used were very similar (%gain is maximum for the range 75,000-120,000 MWHr). That is in contrast to the tendency of the Maximize Value of Energy Production, which increases as total generation increases (highest in the 100,000-135,000 MWHr range). Finally Figure 6.24 compares the probability distribution functions for the three objective functions.

Table 6.5. Total Generation and Difference in Plant Generation, and % Gain for the Postmortem Analysis Studies, Maximize Efficiency Objective Function (June 1998 – April 1999)

Date	Total Gen.	ΔGMS	ΔPCN	ΔMCA	ΔREV	%Gain
09-Jun-98	59553	-79	1205	2891	-4017	0.87
17-Jun-98	44669	2289	1598	3161	-7048	0.02
21-Jun-98	19062	-3652	-668	162	4159	-0.78
23-Jun-98	35507	1402	316	3114	-4832	-0.07
24-Jun-98	30545	749	-657	2144	-2237	-0.56
28-Jun-98	46561	5169	1707	-81	-6795	1.17
03-Jul-98	55766	4530	2009	-5971	-568	0.57
07-Jul-98	79718	-1753	224	-2802	4331	-0.19
09-Jul-98	78857	5409	2030	-6074	-1364	0.60
13-Jul-98	33366	-1957	-331	1287	1001	0.98
15-Jul-98	71525	5787	2437	-8203	-21	0.37
20-Jul-98	58159	11305	2845	-5219	-8931	1.33
21-Jul-98	89682	3762	1702	-7733	2296	0.19
24-Jul-98	93035	-1101	583	-347	865	0.29
28-Jul-98	113364	9559	3172	-7797	-4934	0.84
29-Jul-98	111227	9617	2871	-6203	-6285	0.89
06-Aug-98	112910	9467	3325	-6037	-6755	0.93
09-Aug-98	78857	5409	2030	-6074	-1364	0.60
11-Aug-98	105868	16993	5379	-15591	-6781	1.55
25-Aug-98	135469	11735	3648	-8940	-6443	0.84
26-Aug-98	136915	8824	2872	-8492	-3203	0.65
28-Aug-98	135119	5866	2335	-8090	-111	0.50
01-Sep-98	138475	6611	2551	-7103	-2059	0.01
03-Sep-98	139334	4676	1757	-7704	1271	0.37
22-Sep-98	119586	-53	894	-2522	1680	0.47
24-Sep-98	119588	-937	810	-2807	2934	0.27
25-Sep-98	84866	-3877	-20	-5946	9843	1.09
14-Oct-98	95780	-2493	-35	-3936	6464	0.48
20-Oct-98	124059	-6190	-630	-681	7502	0.55
21-Oct-98	115389	-5653	-2489	-6802	14944	0.89
12-Nov-98	133766	-12711	-2628	6413	8926	1.68
16-Nov-98	118763	-22597	-5257	10241	17613	2.70
23-Nov-98	115617	-18885	-4320	10388	12817	1.67
01-Dec-98	120762	-1426	-126	-4522	6075	0.74
02-Dec-98	146835	-12910	-3634	1948	14596	1.44
10-Dec-98	129302	-1307	-23	-4416	5745	0.68
11-Dec-98	128103	-10546	-2456	2615	10388	1.56
22-Dec-98	145013	-13377	-2407	3366	12418	1.60
06-Jan-99	123423	249	1325	-4476	2902	1.19
25-Jan-99	91891	-6860	-829	-920	8609	1.09
29-Jan-99	107038	-7134	-1873	1591	7416	0.74
07-Feb-99	78841	-15561	-3679	11001	8239	2.09
11-Feb-99	110966	-13616	-2820	3566	12870	2.68
12-Feb-99	101941	-19224	-4966	9935	14256	3.48
22-Feb-99	108372	-11311	-2617	5288	8640	2.29
09-Mar-99	90767	-14	467	-4516	4063	0.59

Table 6.6. Date, Total Generation Gain for the Postmortem Analysis Studies, and for Max. Efficiency, Min. Cost of Water Used and Max. Value of Production Objective Functions (June 1998 – April 1999)

Date	Total Generation	Max Efficiency %Gain	Min Value of Water Used %Gain	Max Value of Production %Gain
09-Jun-98	59553	0.87	0.818	0.5
17-Jun-98	44669	0.02	0.015	-0.825
21-Jun-98	19062	-0.78	-0.208	Infeasible*
23-Jun-98	35507	-0.07	-0.03	Infeasible*
24-Jun-98	30545	-0.56	0.21	Infeasible*
28-Jun-98	46561	1.17	0.61	-0.05
03-Jul-98	55766	0.57	0.381	-0.58
07-Jul-98	79718	-0.19	0.219	-0.781
09-Jul-98	78857	0.60	0.5	-0.05
13-Jul-98	33366	0.98	1.399	Infeasible*
15-Jul-98	71525	0.37	0.336	Infeasible*
20-Jul-98	58159	1.33	1.23	-0.43
21-Jul-98	89682	0.19	0.119	Infeasible*
24-Jul-98	93035	0.29	0.285	-0.19
28-Jul-98	113364	0.84	0.78	0.182
29-Jul-98	111227	0.89	0.819	0.188
06-Aug-98	112910	0.93	0.942	0.18
09-Aug-98	78857	0.60	0.757	-0.047
11-Aug-98	105868	1.55	0.791	0.135
25-Aug-98	135469	0.84	0.595	0.09
26-Aug-98	136915	0.65	0.514	0.146
28-Aug-98	135119	0.50	0.391	0.133
01-Sep-98	138475	0.01	0.58%	0.21%
03-Sep-98	139334	0.37	0.3652	0.123
22-Sep-98	119586	0.47	0.456	0.229
24-Sep-98	119588	0.27	0.29	-0.02
25-Sep-98	84866	1.09	1.08	Infeasible*
14-Oct-98	95780	0.48	0.517	0.35
20-Oct-98	124059	0.55	0.604	0.449
21-Oct-98	115389	0.89	1.247	Infeasible*
12-Nov-98	133766	1.68	1.72	0.038
16-Nov-98	118763	2.70	1.89	0.183
23-Nov-98	115617	1.67	0.97	-0.47
01-Dec-98	120762	0.74	0.983	0.596
02-Dec-98	146835	1.44	0.558	0.162
10-Dec-98	129302	0.68	0.654	0.496
11-Dec-98	128103	1.56	1.256	0.706
22-Dec-98	145013	1.60	1.232	0.07
06-Jan-99	123423	1.19	1.09	1.002
25-Jan-99	91891	1.09	1.181	0.315
29-Jan-99	107038	0.74	0.684	0.156
07-Feb-99	78841	2.09	3.173	Infeasible*
11-Feb-99	110966	2.68	2.726	-0.328
12-Feb-99	101941	3.48	3.51	-0.11
22-Feb-99	108372	2.29	1.96	0.286
09-Mar-99	90767	0.59	1.213	0.46

* Infeasible due to Mica fish flush operation in June, or due to other limiting constraints (e.g., min. REV generation limit, forebay limits, etc.).

Table 6.7. Summary of Statistical Tests of Results in the Postmortem Analysis Studies

Measure	Objective Function		
	Max. Efficiency	Min Cost of Water Used	Max. V. Energy Production
Average	0.91	0.93	0.11
Maximum	3.48	3.51	1.00
Minimum	-0.78	-0.21	-0.83
Standard Deviation	0.82	0.80	0.40
Kurtosis	1.45	2.44	0.63
Median	0.79	0.77	0.14
Skewness	0.83	1.51	-0.26
Expected Gain, %	1.27	1.19	0.25
Average Generation, MWHr	97628	97628	97628
Expected Gain, MWHr	1245	1165	249
Expected Daily Gain (@ $25/MWHr), $	31114	29136	6217
Expected Annual Gain, $ (Million)	11.36	10.63	2.27

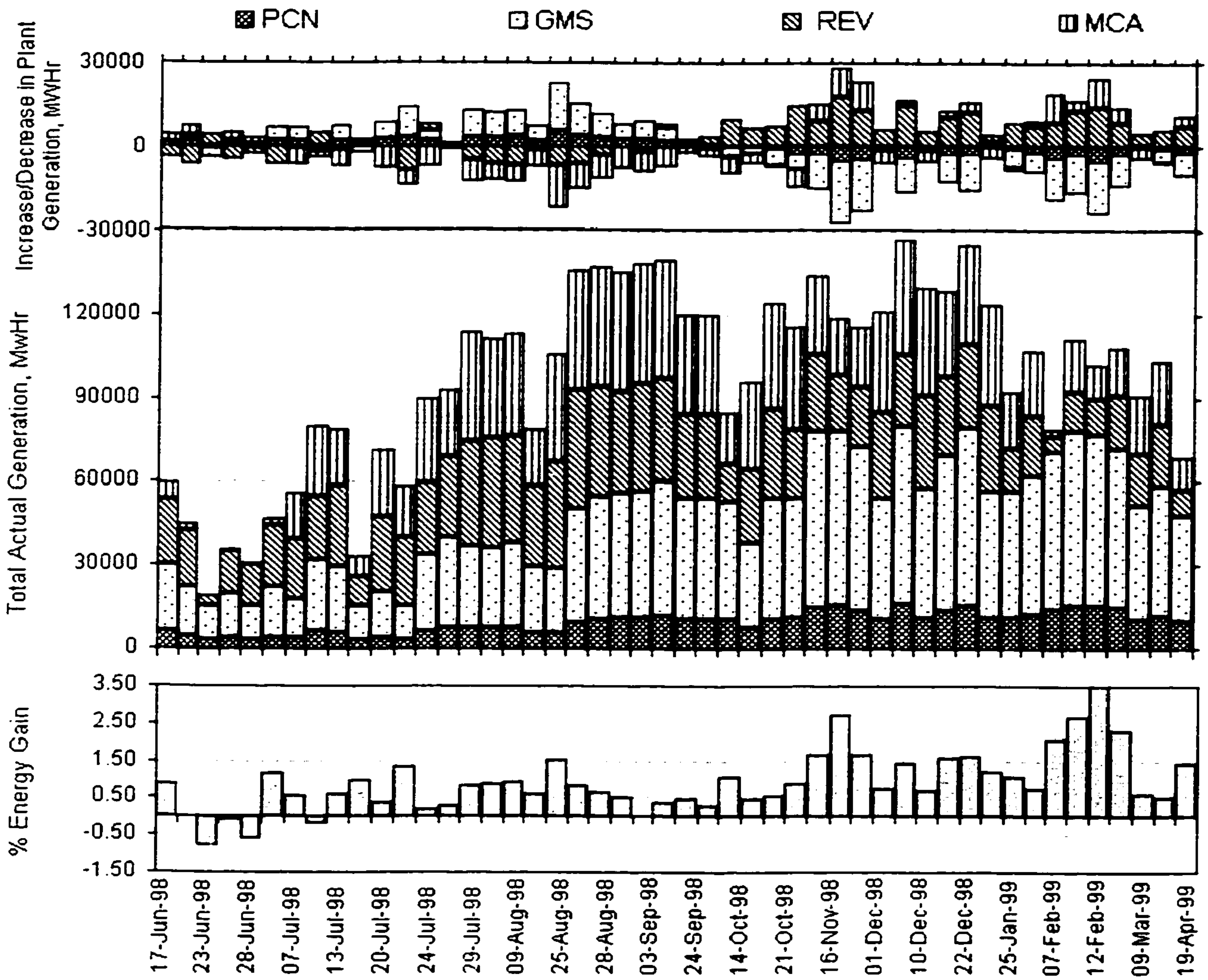


Figure 6.14. Actual Generation Allocation, Difference in Optimized Schedule, and Gain in Stored Energy: Max. Efficiency Objective Function.

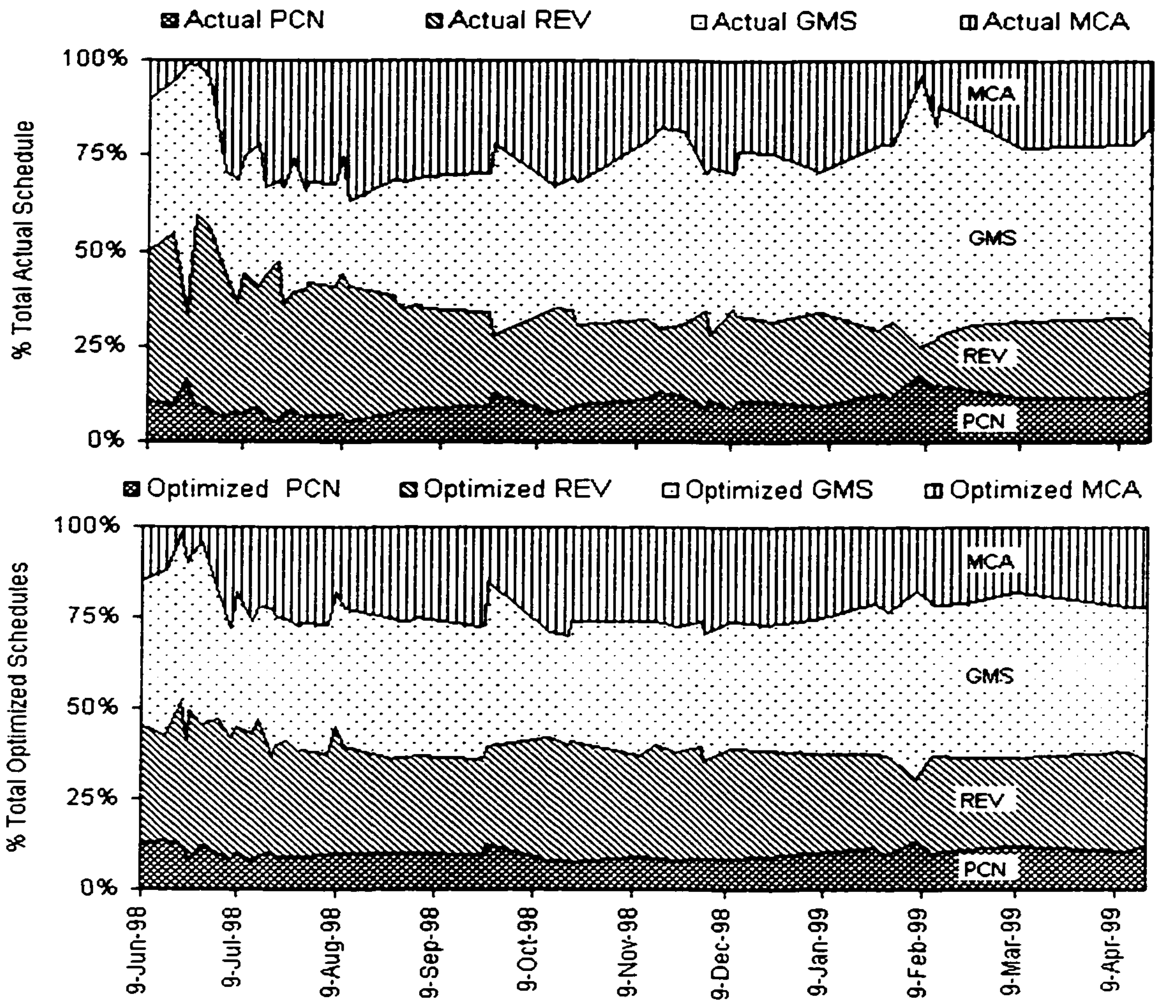


Figure 6.15. Allocation of Generation for Actual and Optimized.

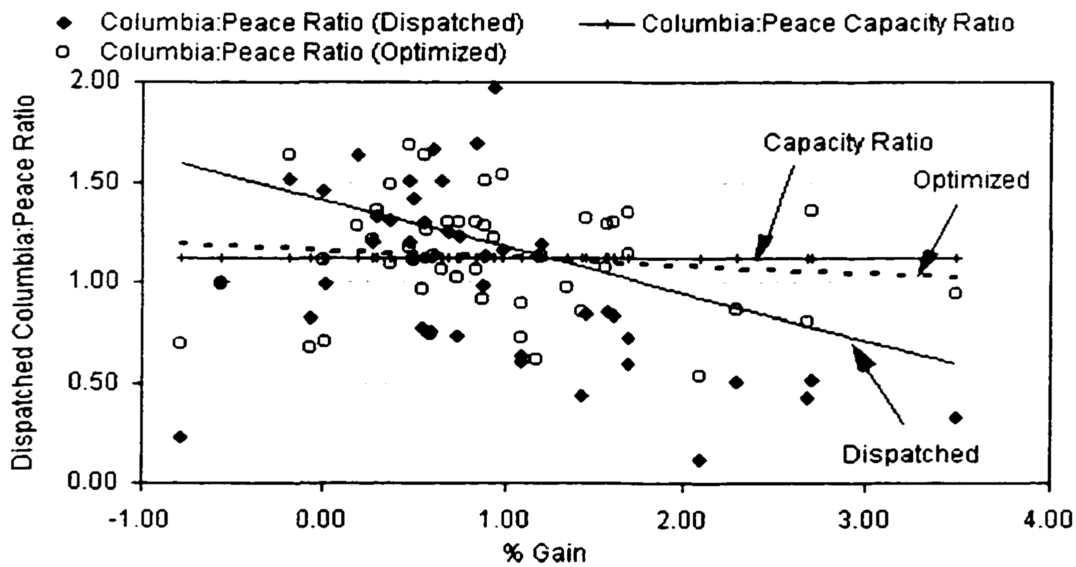


Figure 6.16. Comparison between Optimized and Dispatched Columbia: Peace Ratio, and Capacity Ratio.

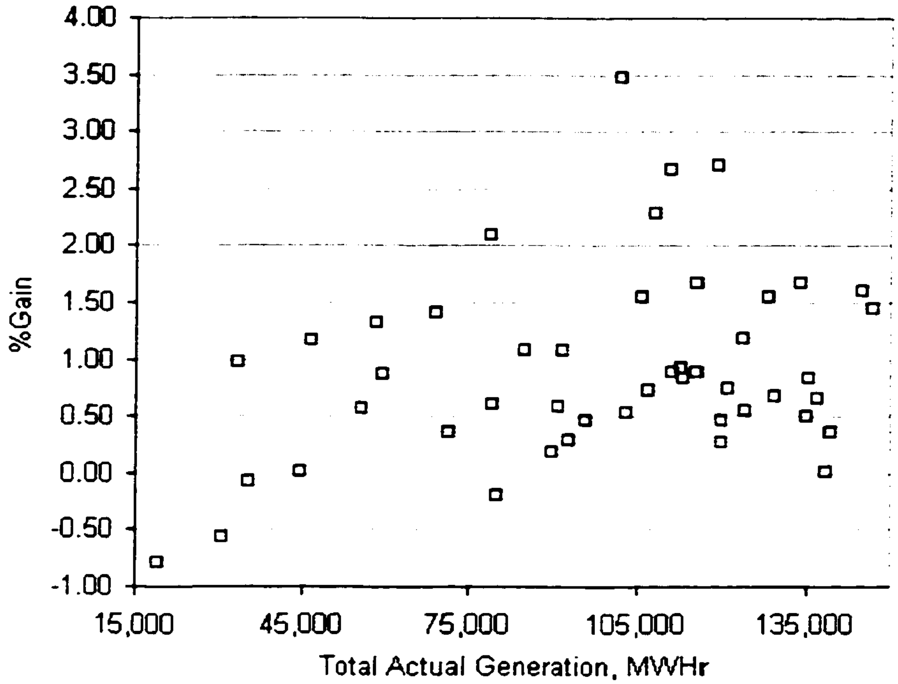


Figure 6.17. Variation of Energy Gain with Total Generation, Maximize Efficiency Objective Function.

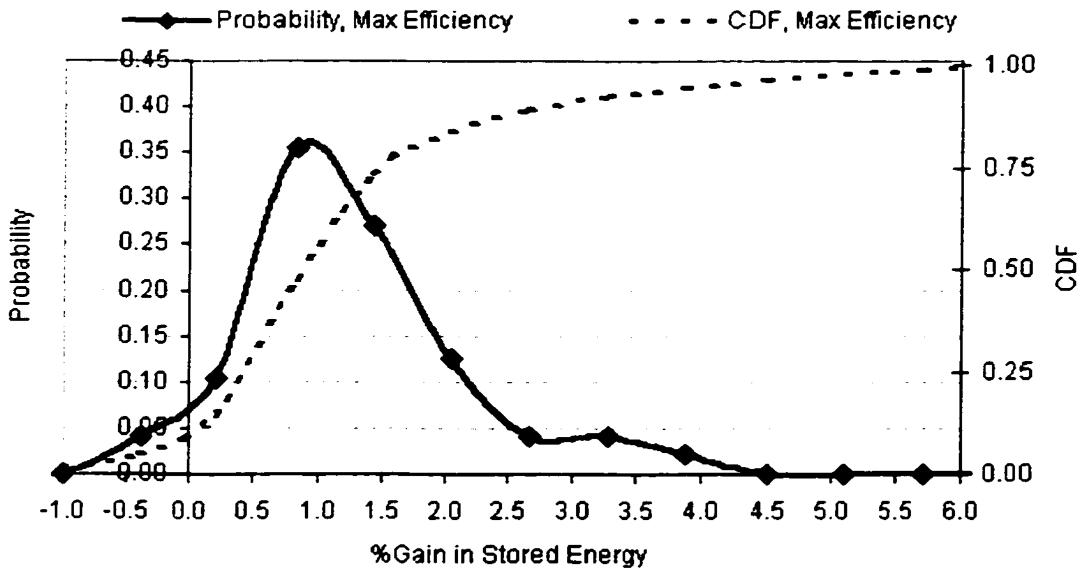


Figure 6.18. Probability and Cumulative Distribution of %Gain in Stored Energy: Max. Efficiency Objective Function.

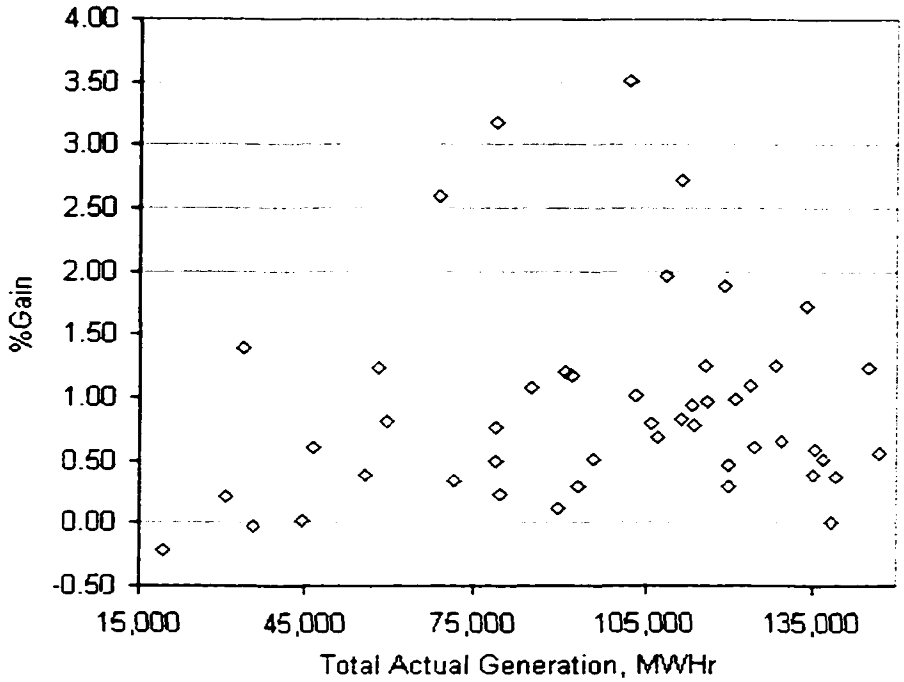


Figure 6.19. Variation of Value Gain with Total Generation, Minimize Cost of Water Used Objective Function.

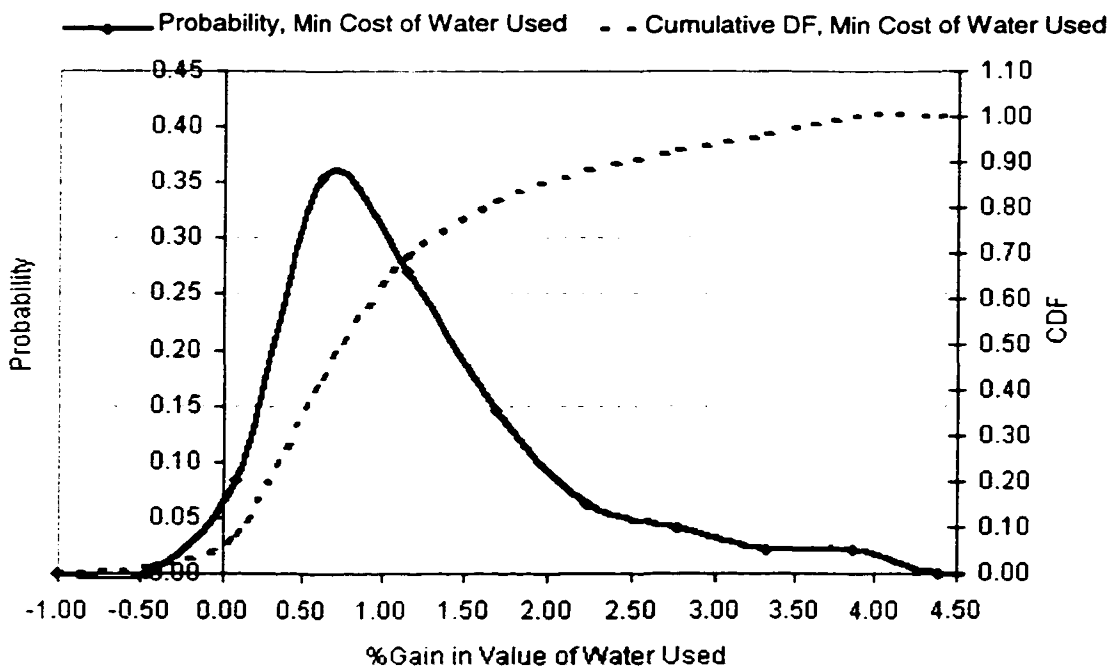


Figure 6.20. Probability and Cumulative Distribution of %Gain in Value of Stored Water: Min. Cost of Water Used.

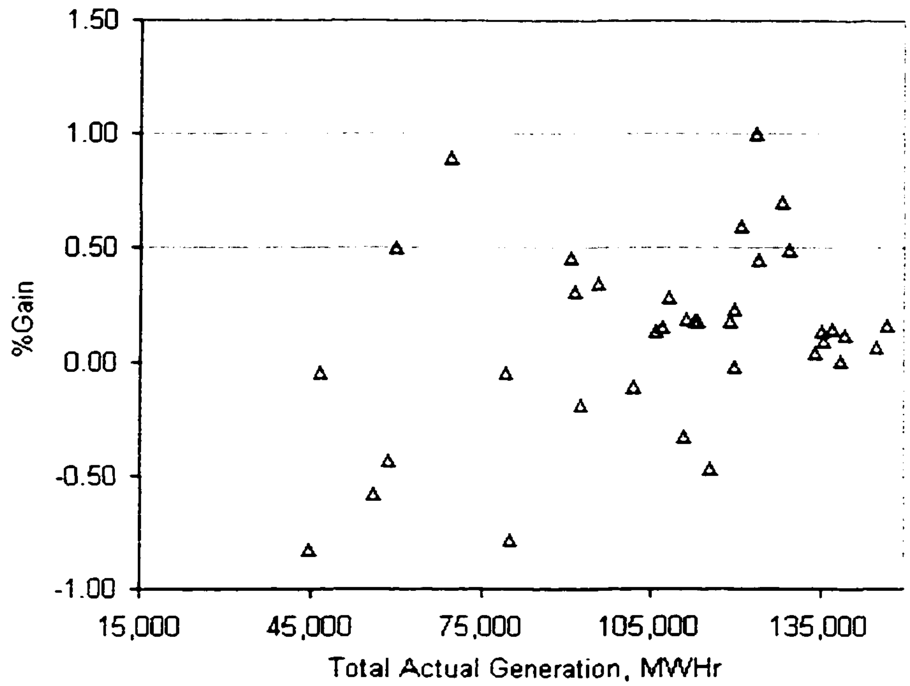


Figure 6.21. Variation of Energy % Gain with Total Generation: Maximize Production Objective Function.

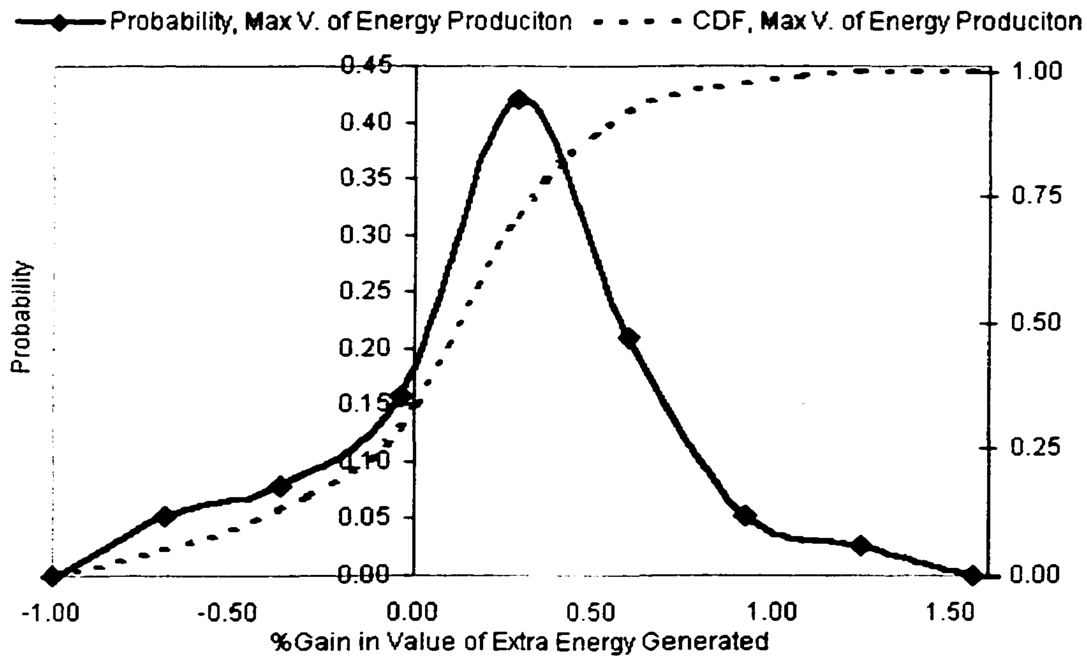


Figure 6.22. Probability and Cumulative Distribution Function of %Gain in Value of Extra Energy Generated: Max. Value of Production.

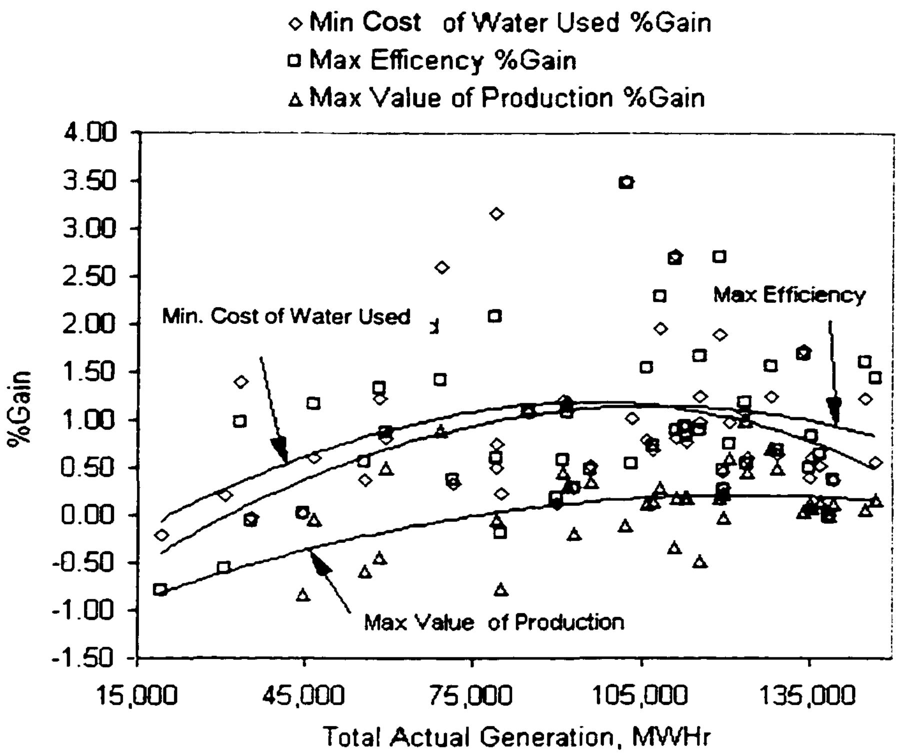


Figure 6.23. Comparison of % Gain for the three Objective Functions.

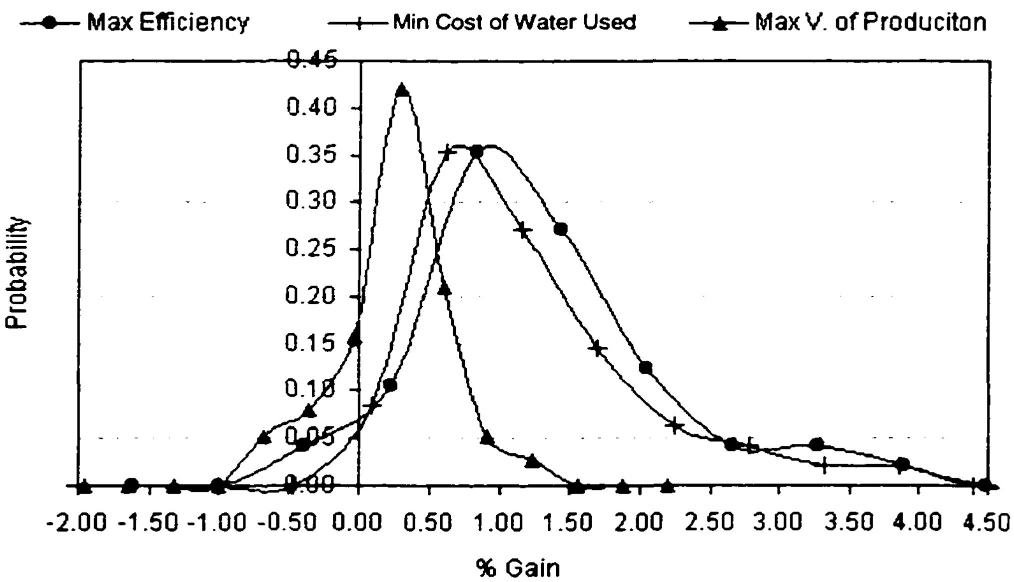
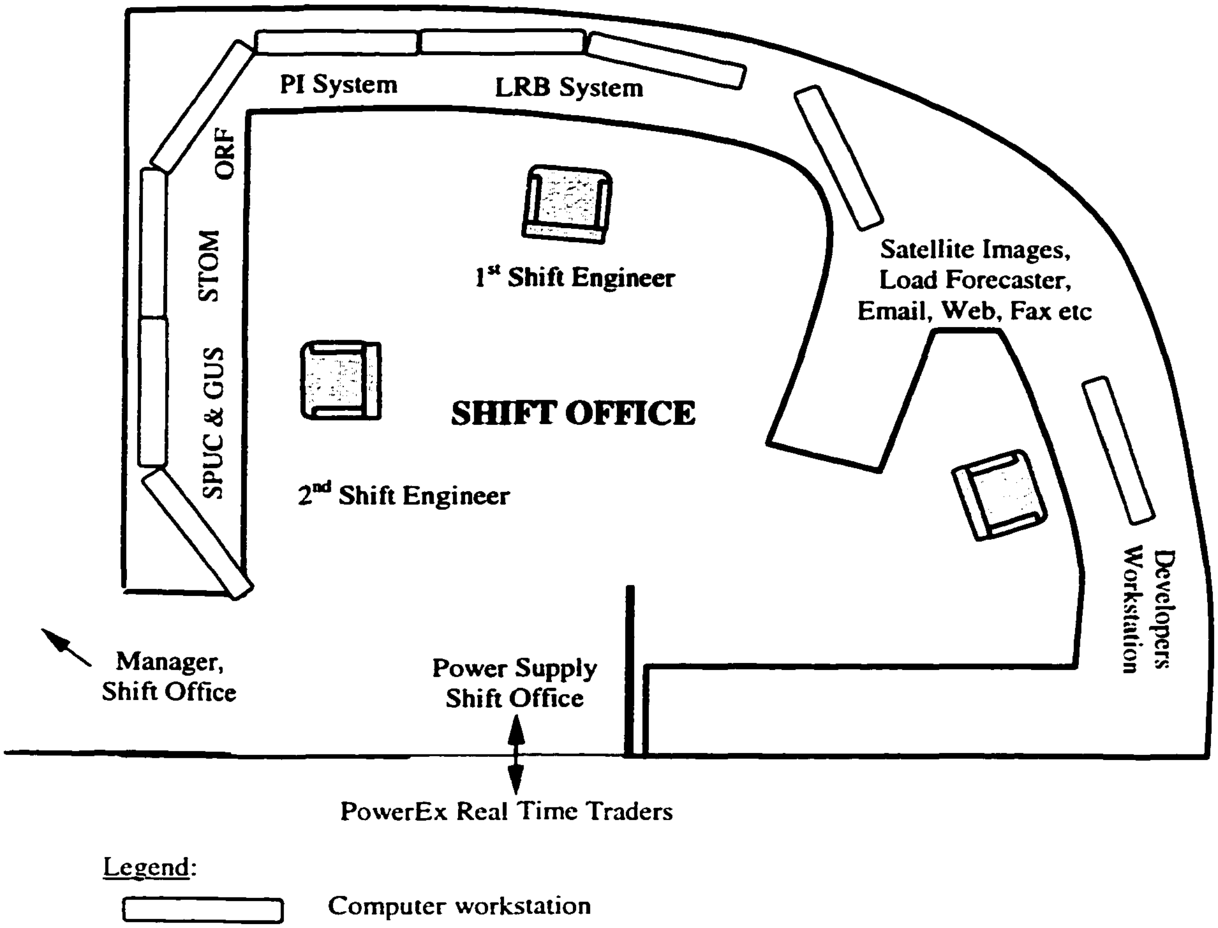


Figure 6.24. Comparison of Probability of % Gain for the Three Objective Functions.

6.2.3. Structure and Objectives of Implementation in Production Mode

Implementation of STOM in production mode was carried out during the months January to May 1999. The initial phase focused on assessing the type and structure of marketing input data needed to run the Maximize the Profit objective function in production mode. Marketing data included forecast spot prices for Alberta and US electricity markets, and the tie line transfer limits to and from the two markets. The setup to transfer marketing data electronically from PowerEx to the LRB system was completed at the initial stage of this phase. Once the required modifications and the electronic transfer of data from PowerEx software systems were completed, several training and testing sessions were carried out during the periods February to May 1999. The objectives of the sessions were to train the Shift Engineers, test, and debug STOM and other new decision support tools in production mode. The testing and training sessions identified the need to modify the input data checking and verification procedure employed by STOM and in the LRB system. The training and testing sessions were structured so that two shift engineers work concurrently in day shift (see Figure 6.25). The 1st Shift Engineer would carry the regular duties of the Shift Engineer (see Section 3.2.4.iii.d for details), while the 2nd Shift Engineer would assess the functionality of assisting the 1st Shift Engineer in setting the generation and trading schedules using the new tools. Management of the Shift Office selected STOM's most expert user among the shift engineers to act as the 1st Shift Engineer, while other Shift Engineers acted as the 2nd Shift Engineer. The author participated in most of the training sessions and provided support for the 1st and 2nd Shift Engineers, particularly to explain the behavior of STOM's new objective function under different operating regimes and market conditions. In addition, the training sessions allowed introduction of sensitivity analysis data and raised questions as to how it could be interpreted and used in production mode.



LRB System: Load-Resource Balance software system (in M.S. Excel)
PI System: Plant Information System (SCADA based).
ORF: Outage Request Form, to update generating unit outages schedules.
STOM: The Short Term Optimization Model.
SPUC: Static Plant Unit Commitment Program.
GUS: Generation Unit Scheduler.

Figure 6.25. Plan of the Shift Office, 14th Floor Park Place, Vancouver.

6.2.4. Results and Discussion of Implementation in Production Mode

To illustrate the results from implementing STOM in production mode, the generation and trading schedules for the four largest hydroelectric plants (GMS, PCN, MCA and REV) and the Burrard thermal station will be used. The planned generation schedule was prepared by one of the Shift Engineers on 2nd day shift. The scheduled plan was prepared for the fourth week of February 1999. During this period the forecast domestic load varied as shown in Figure 6.26. This forecast was derived by the ANNSTALF Neural Netwrok model, and it represented a regular winter-day load with two sharp peaks, one in the morning (9 a.m.) and the other in the afternoon (6 p.m.). The maximum load peaked at 7885 MWHr at 6 p.m. on Monday and Tuesday, while the minimum load for the study declined to 5131 MWHr at 4 a.m. on Sunday. The average load increased on Monday and Tuesday by about 500 MWHr due to forecast colder temperature for these two days. Peak load during the weekend dropped by about 500 MWHr.

The total scheduled system generation for the week amounted to about 1.043 million MWHr, of which, 69% were generated by plants selected for this optimization study. Figure 6.27 shows the distribution of scheduled generation among the plants selected for the optimization run and for other plants in the BC Hydro system.

The operating regime during this period calls for the Peace River flows to be maintained at relatively constant levels to prevent break-up of the ice cover on the Peace River. If the ice cover breaks it could cause an ice jam that could result in extensive flooding of the town of Taylor, located downstream of the Peace Canyon generating facility. For this reason minimum generation limits (i.e., turbine discharge limits) must be maintained at about 500 MWHr. These limits, however, were lowered to 410 MWHr in the last two days of the study, thus allowing PCN to have more freedom to cycle during low and high load hours (see

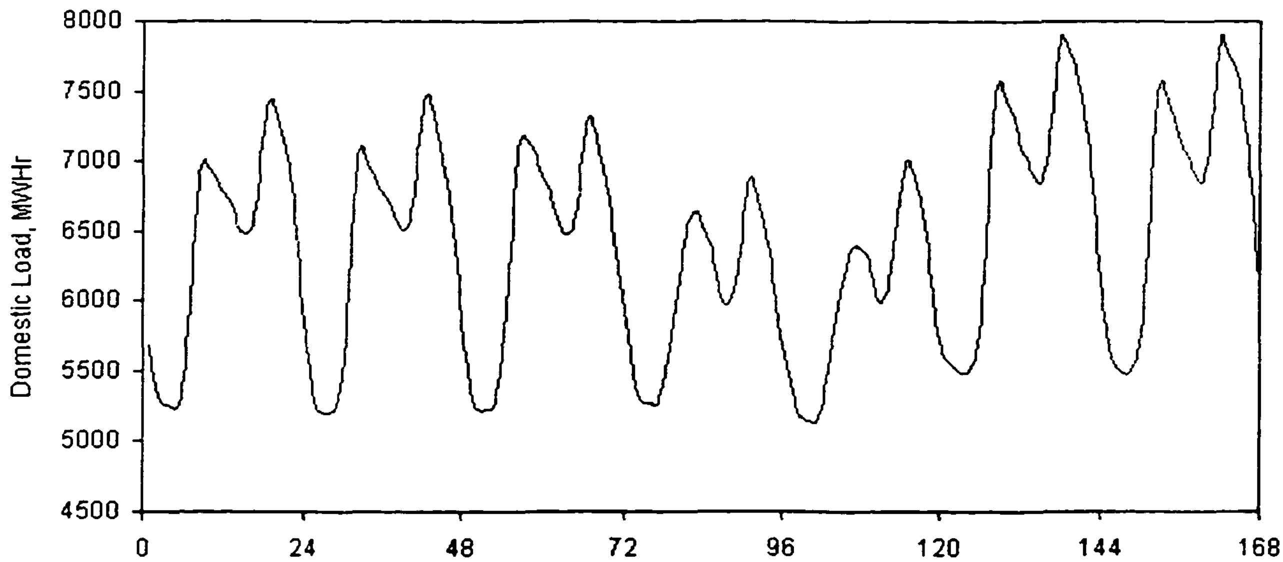


Figure 6.26. Variation of Domestic Load for the Optimization Study.

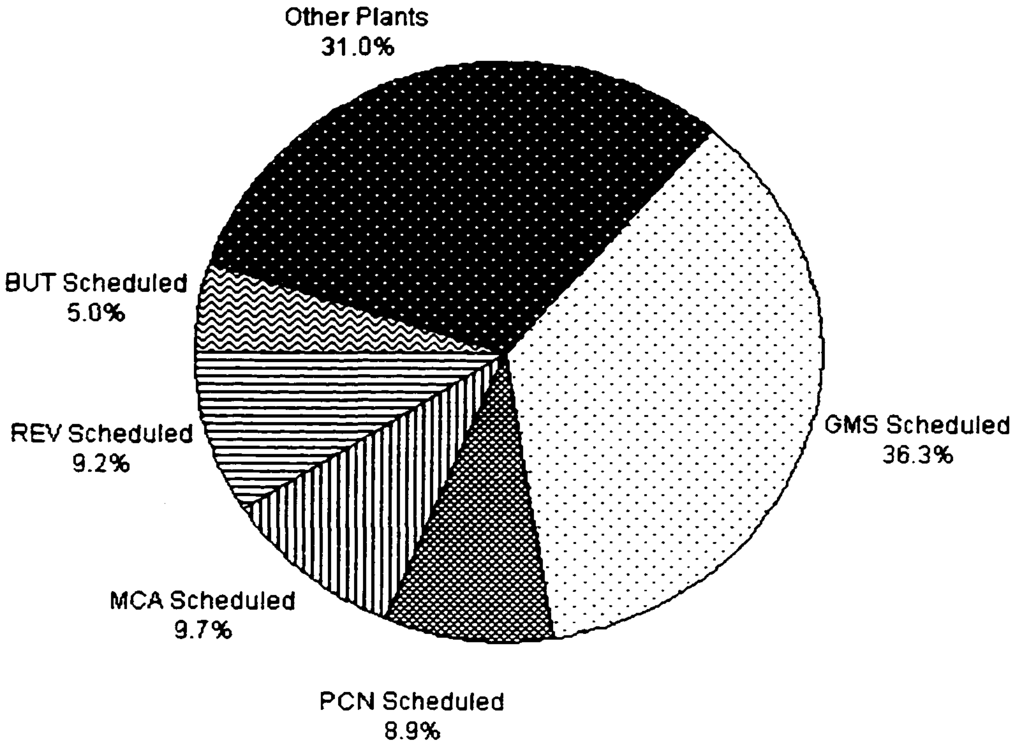


Figure 6.27. Allocation of Generation in the Scheduled Plan.

Figure 6.29). The minimum generation restriction on the PCN affects the mode of operation of GMS, and it restricts it to higher minimum generation levels (see Figure 6.28), which in turn restricts the amount of imports that could be absorbed by GMS during low market conditions. Figure 6.28 shows that GMS maximum generation capacity was scheduled to be lower on Sunday morning and to increase back to its original level Monday morning.

The upper Columbia plants were scheduled to operate in regulation mode -basically to follow fluctuations in domestic load (see Figures 6.30 and 6.31). A capacity increase (334 MW) was scheduled for Mica at hour 79, and a similar increase in capacity was scheduled for Revelstoke (500 MW) on Monday morning.

The forebay level operating regime can be summarized as follows. GMS and MCA forebay levels were drafted by about 50 centimeters and 1.2 meters respectively (Figures 6.28 and 6.30). Note, however, that the rate of scheduled drawdown for MCA forebay was higher after the weekend. PCN forebay levels were scheduled to slightly cycle before the weekend with a downward trend to nearly minimum forebay levels, while during the weekend they were scheduled to cycle and end up close to their maximum operating level (Figure 6.29). The REV forebay levels, on the other hand, were scheduled at an almost constant level before the weekend and thereafter they declined by about 5 centimeters (Figure 6.31).

The forecast spot prices for Alberta and US markets behaved in similar way as the domestic load. The Shift Engineer, in coordination with PowerEx real-time traders, prepared the forecast spot market prices. The spot market prices peaked during morning and evening hours, dropped slightly in-between peaks (10. a.m.-5 p.m.), and were low during late night to early morning hours. Alberta forecast spot market price was generally higher during daytime than US spot market price, except for the evening peak hours (see Figure 6.34). During late night to early morning hours the Alberta spot market price was lower than the US spot market price. This is attributed to the type of Alberta's generating facilities, which are predominantly thermal, and cannot be shut down during nighttime. The forecast net tie line transfer capabilities have varied during day and night, and nearly exhibited a mirror image of the load (see Figure 6.34). The Shift Engineer, in coordination with PowerEx real-time traders, prepared the forecast tie line limits.

The Shift Engineer prepared other input information required to run the Maximize Profit objective function. The information was entered using the Graphical User Interface, as discussed in Section 4.3.2 and detailed in Annex D. It included the following:

- The marginal cost of energy for each generating plant *j*, $Rbch_j$ (in US$/MWHr). Using $Rbch_j$, and HKj^2, the marginal value of water, MVW_j (in mils/m^3), for cascaded hydroelectric generating facilities in a river system, is calculated as follows:
  - Calculate MVW_j for the first downstream reservoir ($j=1$) in the river system:
    $$MVW_1 = Rbch_1 * HK_1 / 3.6$$
  - Calculate MVW_j for the second reservoir ($j=2$) in the river system:
    $$MVW_2 = Rbch_2 * HK_2 / 3.6 + MVW_1$$
  - Calculate MVW_j for the third reservoir ($j=3$) in the river system:
    $$MVW_3 = Rbch_3 * HK_3 / 3.6 + MVW_2$$
  - and so on.
- The operating reserve obligation, which is specified by the user as a fraction of the optimized generation level (e.g., 0.05).
- The regulating margin requirement, which is specified by the user as the magnitude of the available generating capacity to be reserved for regulation purposes (e.g., 200 MW).
- The target forebay level for each reservoir, which is converted in the model to the target storage, which is used in the objective function (see Section 4.6 for details).
- The fixed target forebay level, which is translated in the model as a hard constraint, which fixes the forebay at its scheduled level (see Section 4.6 and Annex D for details).

The results of the optimization run and the scheduled plan are summarized and compared in Figures 6.28-6.34. Figure 6.32 illustrates the generation summary for the planned and optimized schedules. It could be noted that, in general, the optimization model scheduled more generation for exports during high load, and high spot market price hours, backed-off to lower generation levels during medium load hours, and dropped down hydro generation levels to very low levels during low load hours. The optimized generation schedule for the Burrard thermal station (BUT) was unchanged. This is because the plant was heavily restricted by its minimum and maximum generation limits, and by the total gas contract for

[2] The value of HK is constant for each plant and it represents the energy conversion rate for each m^3/s used. It is calculated in STOM by taking the energy conversion rate of the third breakpoint in the PWL function and using the forebay level of the last time step in the study. Note that the third point in the PWL function was chosen to represent the most efficient point for the last segment of the generation production function. The last time step in the study was chosen since it corresponds to the target forebay level used in the objective function, and as specified by the user.

the study period. It can also be seen that during the weekend, Monday, and Tuesday, exports were high (see Figure 6.34). This is because more system capacity was made available (due to lower load on the weekend and higher generating capacity on Monday and Tuesday), while spot market prices were much higher than the system marginal cost, *Rbch* (see Figure 6.34).

Figures 6.28-6.31 compares the optimized and planned generation and reservoir forebay schedules. It could be noted that the optimized forebay levels are significantly different from the scheduled plan, in many ways. First, the optimized forebay schedules for the large plants (GMS and MCA) stored more water at GMS forebay (about 10 cm), while it drafted MCA forebay by about 30 cm.

The Peace Canyon forebay level was raised during night and was drafted during morning hours, and it was also slightly drafted before evening peak load hours. The optimization model, therefore, prepared the Peace Canyon forebay levels for GMS generation to peak during morning and evening peak load hours (see Figures 6.28 and 6.29). Figure 6.29 also illustrates the effect of the rise and fall in PCN forebay levels on its maximum generation capacity, which increases when the forebay level is high and drops when it is low. The REV forebay levels cycled slightly to operate the plant more efficiently, in response to the export and import trading schedules, and to fluctuations in MCA generation. Often, REV forebay was used by the system operations engineers to accommodate high export and/or import levels. This mode of operation was also confirmed by STOM results. For instance, it can be seen in this study that REV forebay levels were drafted by heavy export loads during Wednesday-Saturday, were raised back to higher levels on Sunday, and were drafted by heavy exports on Monday and Tuesday.

Finally, Figure 6.33 illustrates the hourly distribution of the regulating margin requirement (RMR) and the operating reserve obligation (ORO). It could be noted that ORO closely follows the behavior of the optimized generation schedules, while the distribution of RMR is significantly different. Figure 6.33 shows that for most hours, PCN provided for RMR, and in particular during high load hours. Allocation of RMR in this way allowed PCN to generate at its minimum allowable level and increase system generation efficiency. It also allowed PCN and GMS to hold their forebay levels at higher operating levels, and at the same time have allowed MCA and REV to export more during high and peak load periods. The remainder of RMR was taken almost entirely by GMS, which also caused GMS forebay levels to remain higher than MCA. It should be noted that this pattern of RMR allocation is typical for the period when ice formation restricts the mode of operation in the Peace System by restricting the changes in flow.

Performance of the Maximize Profit objective function is measured by comparing the value of the objective function (value of spot trading schedules and the increment/decrement of value of water stored in reservoirs) for both the pre-planned and the optimized schedules.

In summary, the Maximize Profit optimization model behaved in an acceptable way and met user's expectations. In arriving at the generation and trading schedules, the optimization model factors-in all user's specified information on the modeled systems and on market conditions. It produces reliable and believable generation and reservoir schedules that can aid the Shift Engineer in arriving at the decision on when and how much to import and/or export and how much thermal energy to generate as well as when, where and how much water to store in or draft from reservoirs while meeting the domestic load and other system and market constraints.

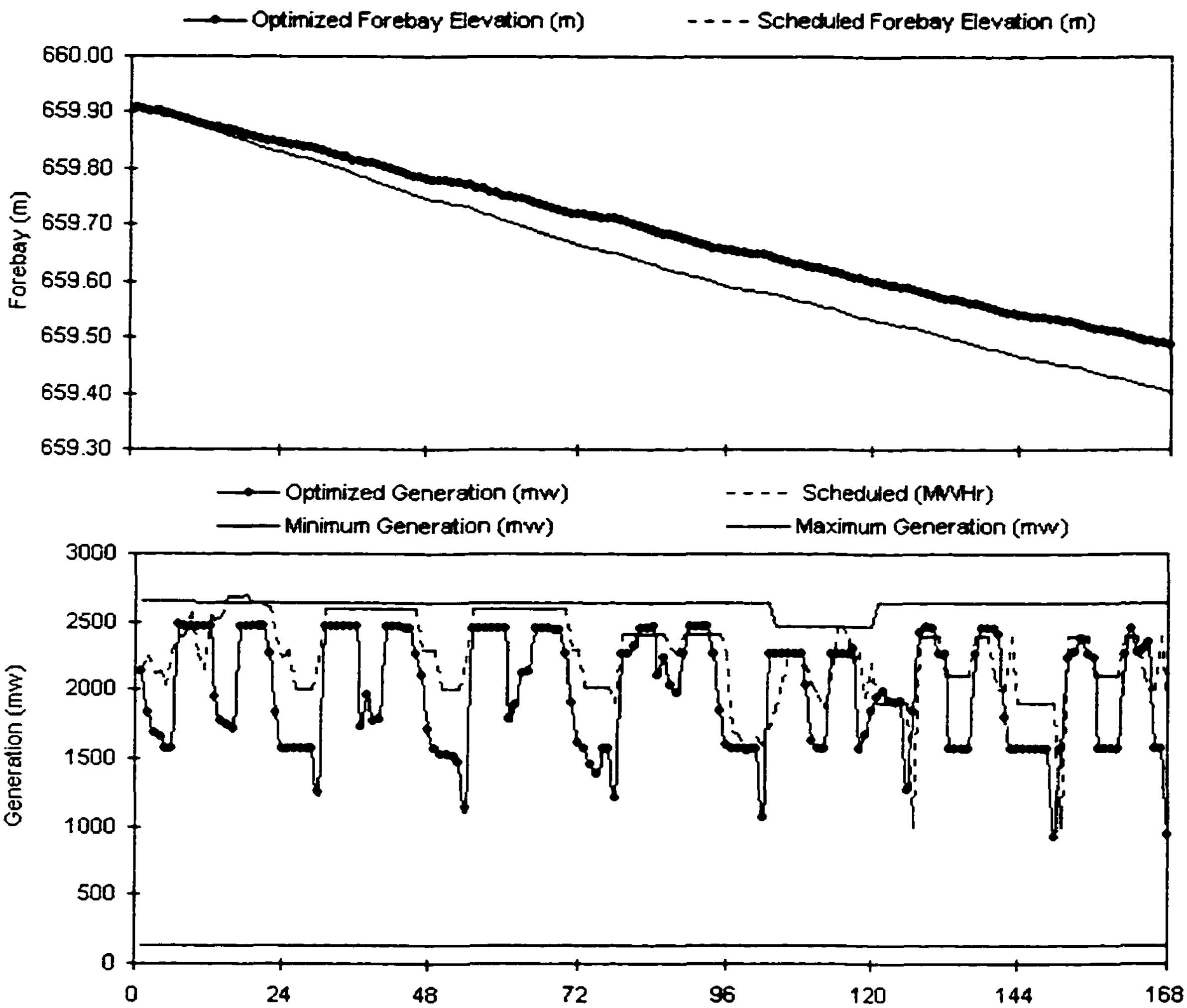


Figure 6.28. Scheduled and Optimized GMS Forebay Levels and Plant Generation.

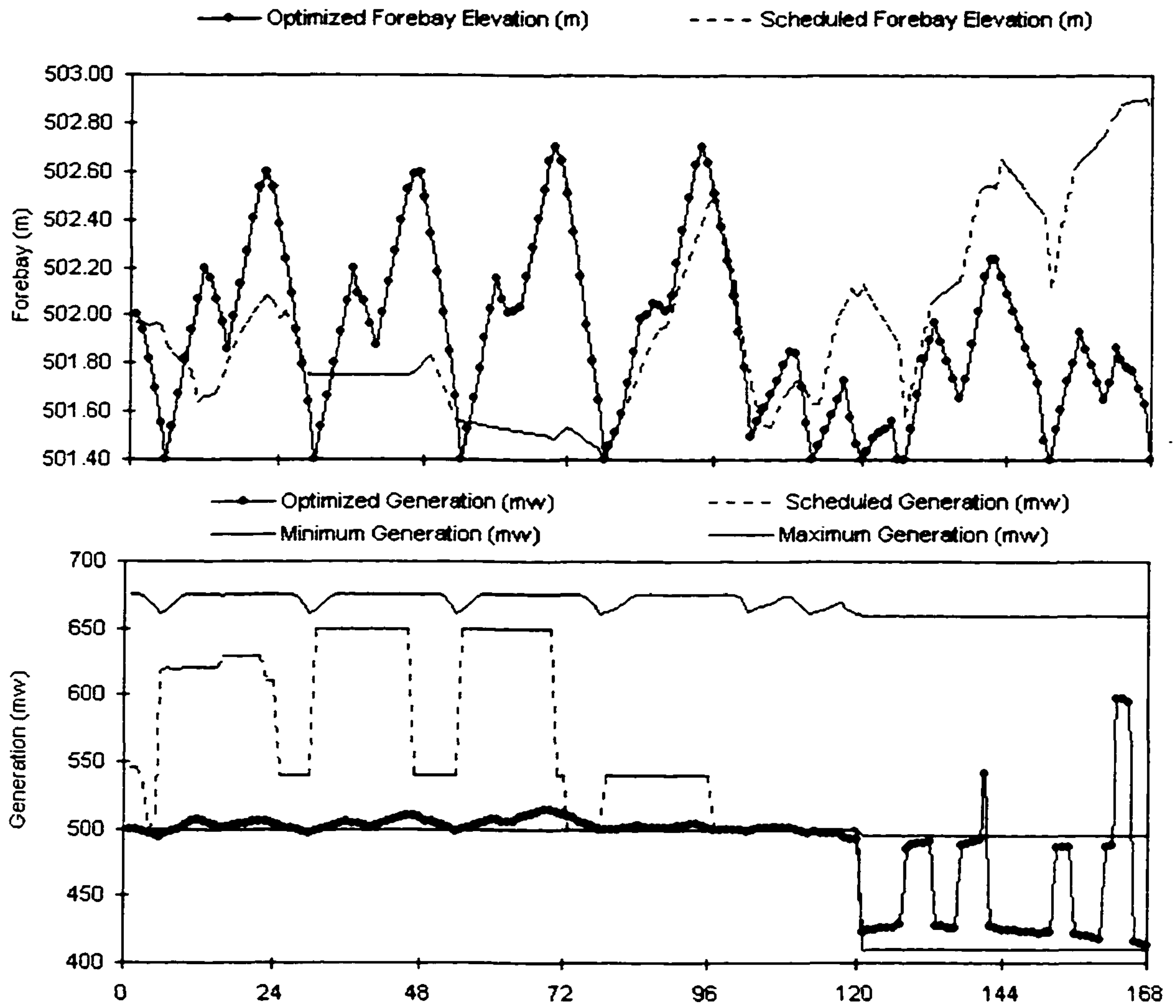


Figure 6.29. Scheduled and Optimized PCN Forebay Levels and Plant Generation.

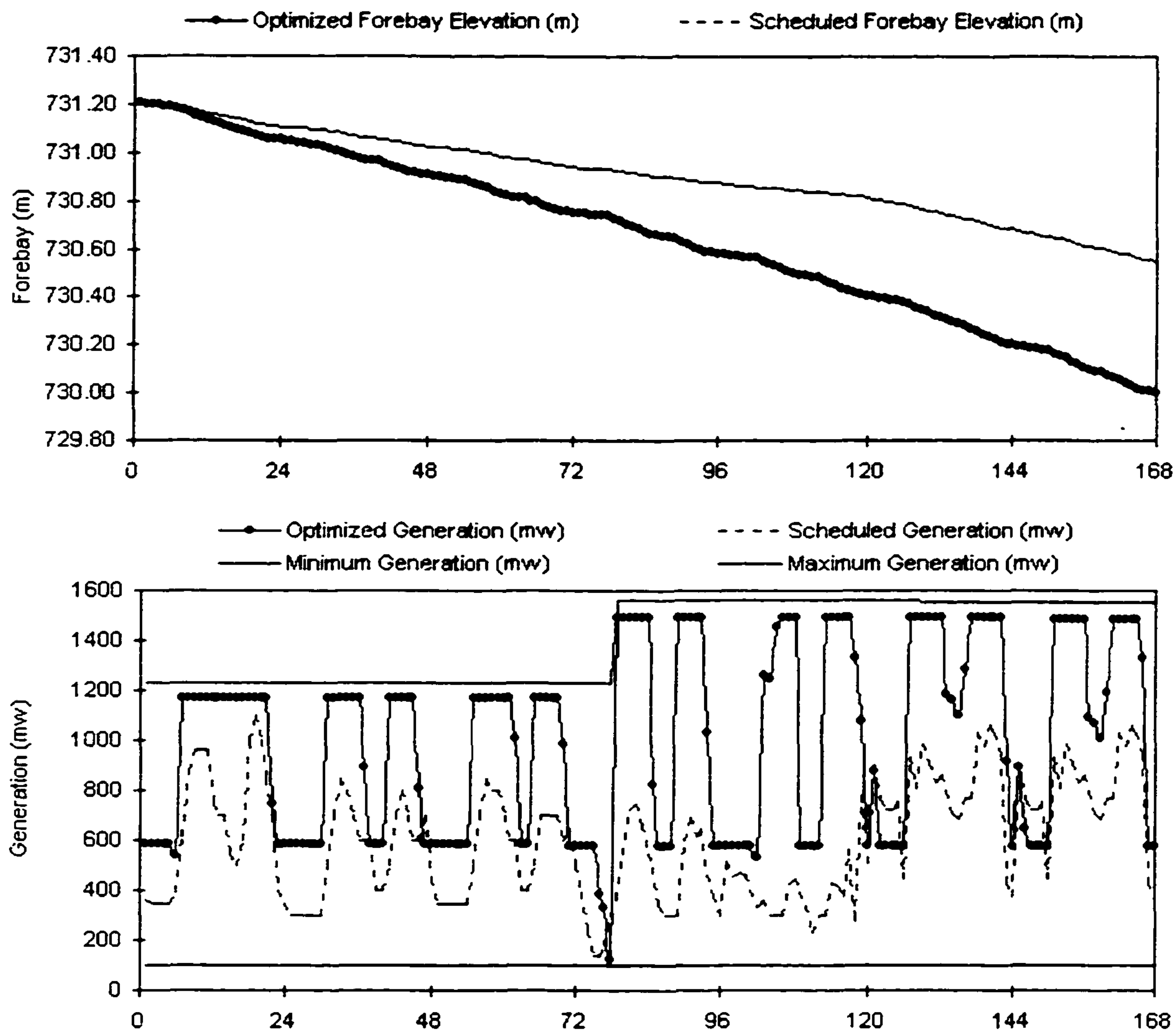


Figure 6.30. Scheduled and Optimized MCA Forebay Levels and Plant Generation.

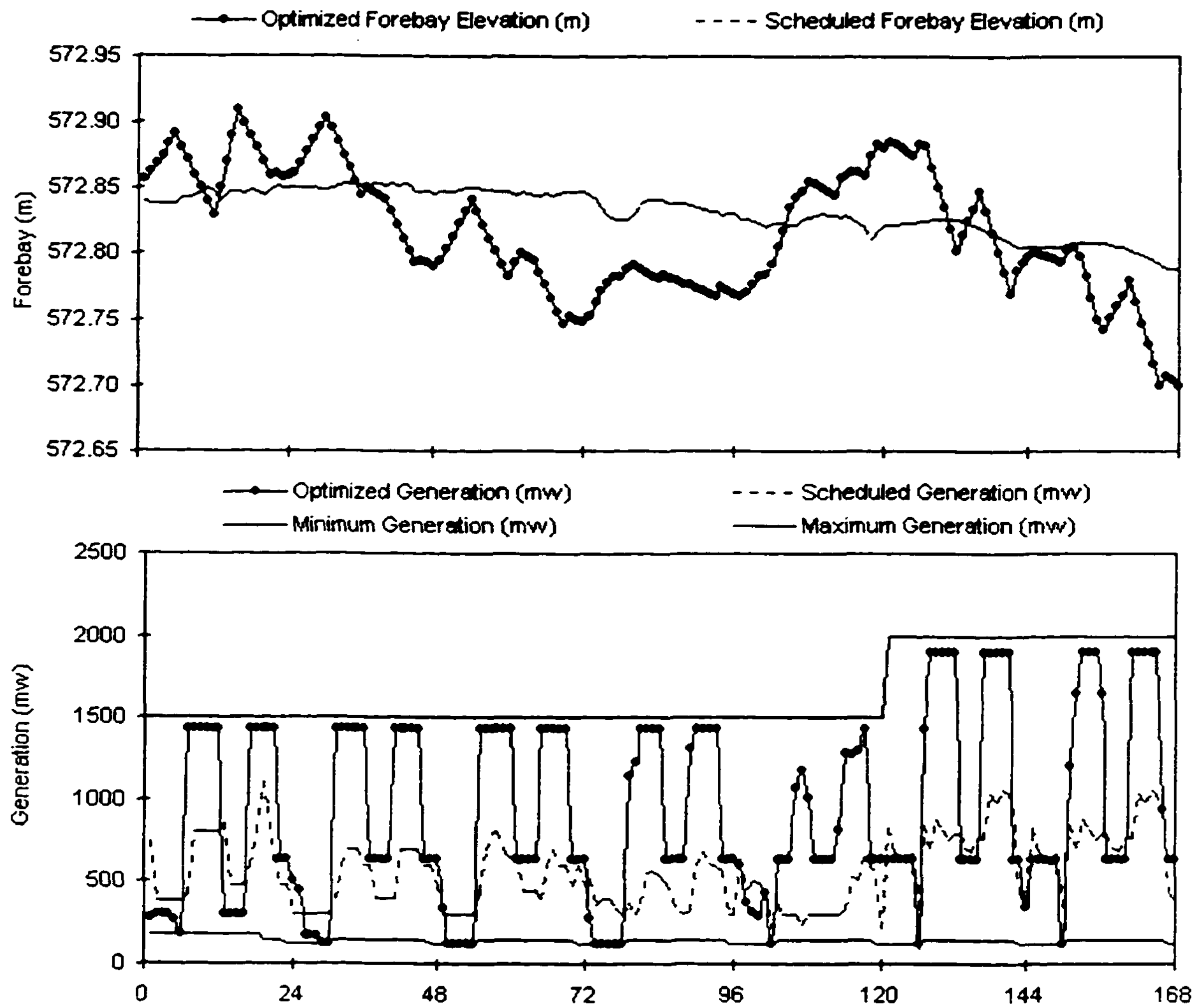


Figure 6.31. Scheduled and Optimized REV Forebay Levels and Plant Generation.

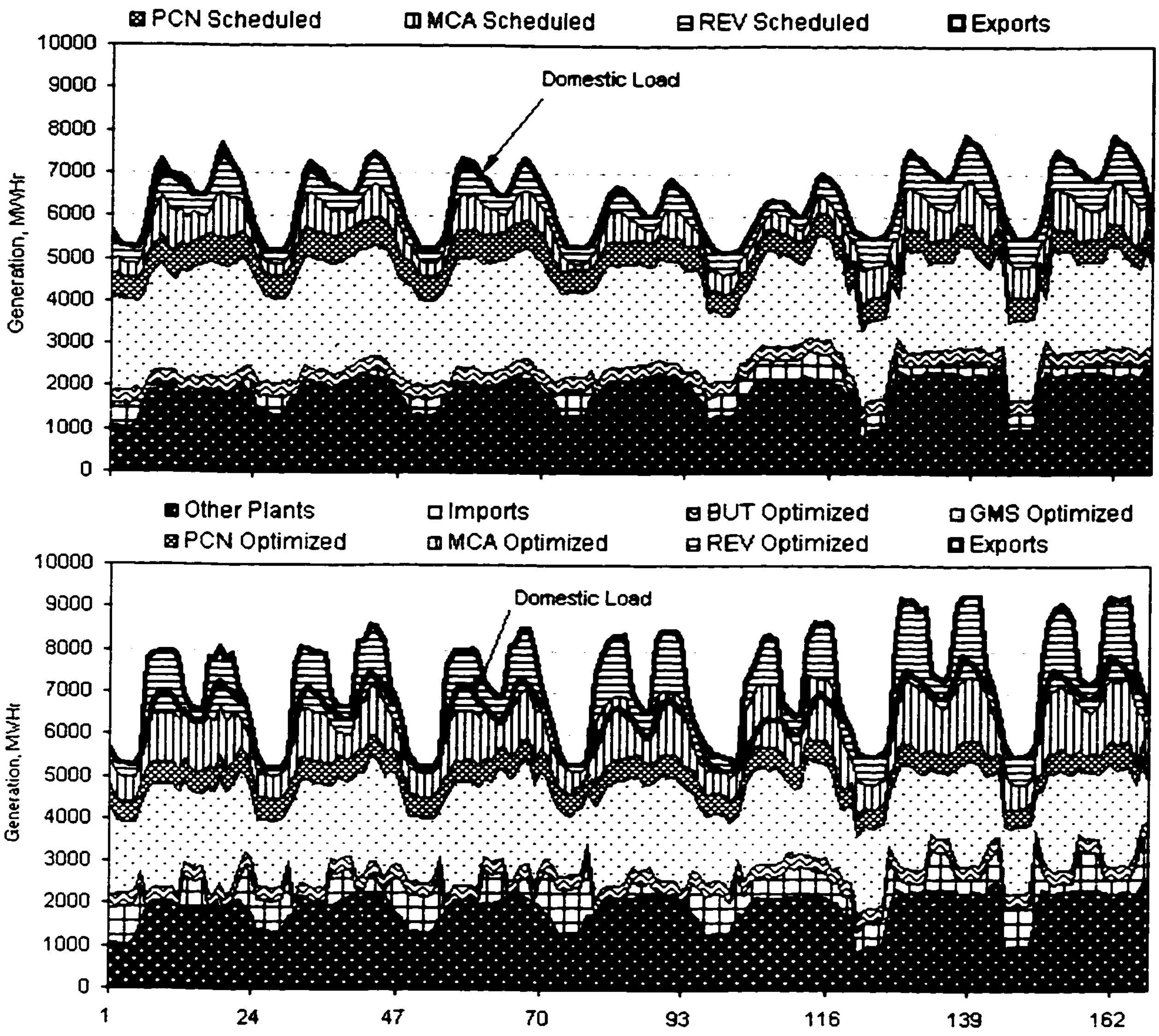


Figure 6.32. Scheduled and Optimized Generation Summary.

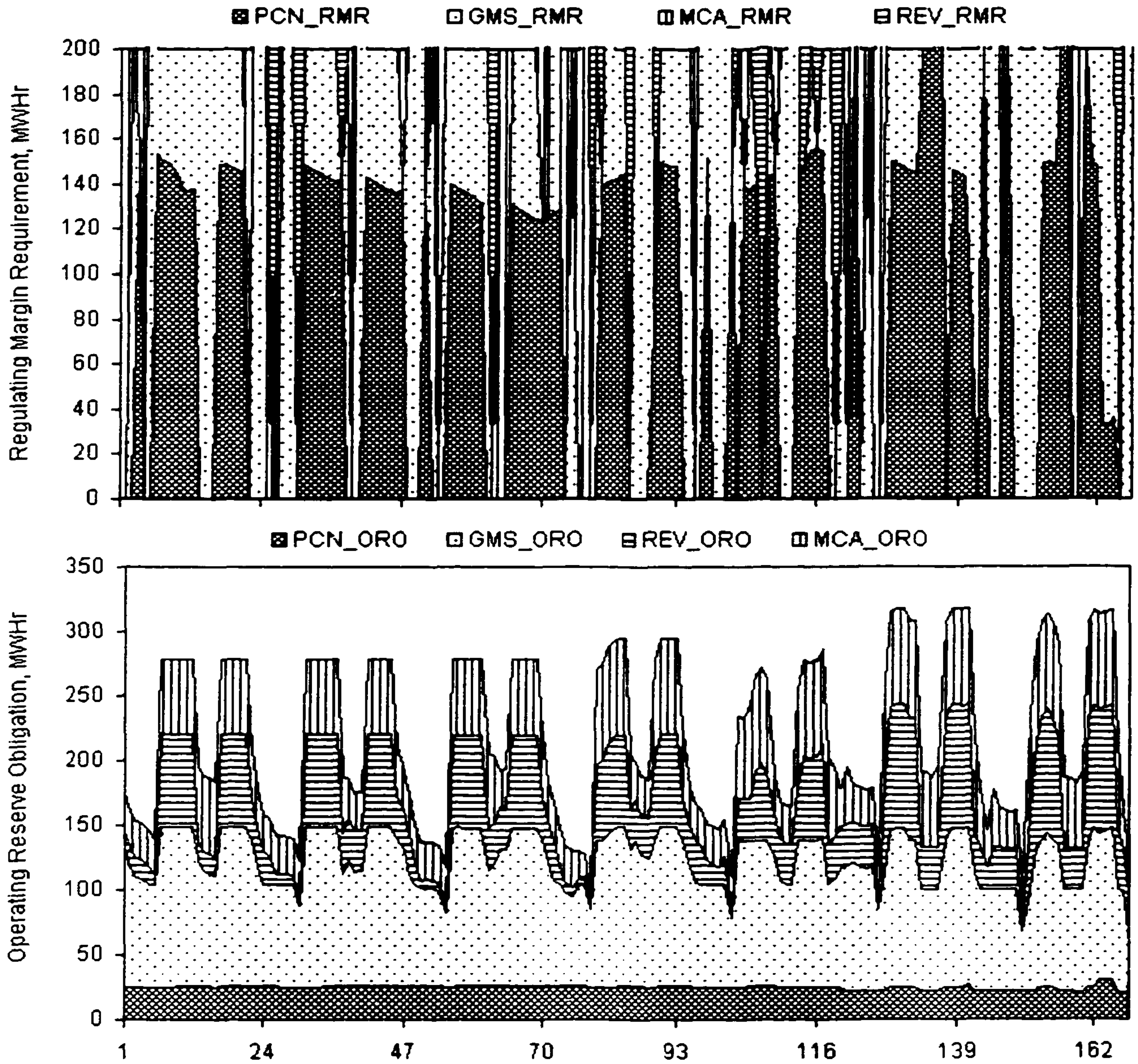


Figure 6.33. Operating Reserve Obligation and Regulating Margin Requirement.

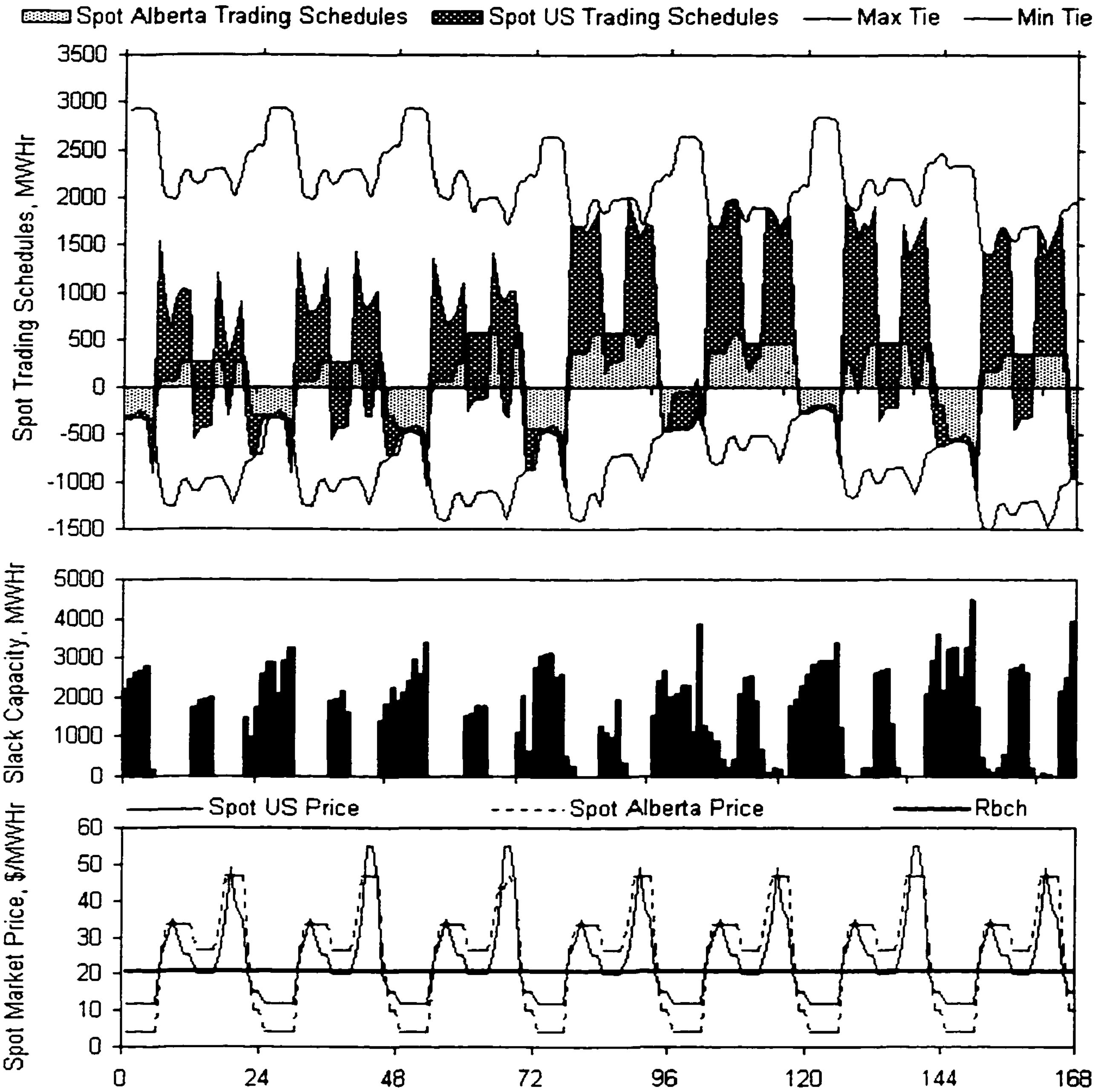


Figure 6.34. Optimized Trading Schedules, Tie Limits, System Capacity Slack, and Spot Prices.

6.2.5. Sensitivity Analysis Information

Aside from the optimized generation, reservoir, and trading schedules, one of the major benefits of using linear programming is the derived sensitivity analysis information that can be obtained from the simplex dual variables (Piekutowski et al., 1994; Greenberg, 1993). Dual values (or shadow prices) are the most basic form of sensitivity analysis information. The dual value for a variable is nonzero only when the variable's value is equal to its upper or lower bound at the optimal solution. This is called a non-basic variable, and its value was driven to the bound during the optimization process. Moving the variable's value away from the bound will worsen the objective. The dual value measures the increase in the objective function's value per unit increase in the variable's value. The dual value for a constraint is nonzero only when the constraint is equal to its bound. This is called binding constraint, and its value was driven to the bound during the optimization process. Moving the constraint left hand side's value away from the bound will worsen the objective function value; conversely, loosening the bound will improve the objective. The dual value measures the increase in the objective function's value per unit increase in the constraint bound. For example, the dual value of the load-resource balance equation provides information on the cost of increasing the system load by one unit. Such valuable information derived from the optimization model can be used as indicators for the "Market Clearing Price" in planning spot trading schedules and in operating the system in real time. Other sensitivity analysis information can be used for comparing alternative operating strategies for the system, and to determine the cost of limits imposed on the system (e.g., turbine, generation or tie line limits).

During the first phase of STOM implementation in production mode, sensitivity analysis information was introduced to the Shift Engineers. The following is a brief presentation of sensitivity analysis information as it relates to Maximize the Profit objective function. A case study consisting of 19 generating plants, for a study duration of 168 hours is used. Figures 6.35-6.41 shows the planned and optimized generation and forebay schedules for the 19 plants in the study (for detailed description of the hydroelectric facilities and their operating regime, see Annex D):

- The Stave Falls River system (Figure 6.35), which consists of three generating and associated storage facilities: Allouete (ALU), Stave Falls (SFL), and Ruskin (RUS).
- The Bridge River system (Figure 6.36), which consists of three generating and associated storage facilities: La Joie (LAJ), Bridge (BR), and Seton (SON).
- The Campbell River system (Figure 6.37), which consists of three generating and associated storage facilities: Stratchona (SCA), Ladore (LDR), and John Hart (JHT).
- The Peace River system (Figure 6.38), which consists of two generating and associated storage facilities: G.M. Shrum (GMS) and Peace Canyon (PCN).
- The Columbia River system (Figure 6.39), which consists of two generating and associated storage facilities: Mica (MCA) and Revelstoke (REV).
- The Pend O'Reille (lower Columbia) river system (Figure 6.40), which consists of two generating and associated storage facilities: Seven Mile (SEV) and Waneta (WAN).
- The Cheakamus River system (Figure 6.41), which consists of one generating and storage facility: Cheakamus (CMS).

- The Clowhom River system (Figure 6.41), which consists of one generating and storage facility: Clowhom (COM).
- The Wahleach River system (Figure 6.41), which consists of one generating and storage facility: Wahleach (WAH).
- The Ash River system (Figure 6.41), which consists of one generating and storage facility: Ash (ASH).

For brevity and comparative clarity, the format of the presentation relies on combined illustrations for most of the constraints in the Maximize Profit objective function.

i. The Shadow Price of the Turbine Discharge Limits

The shadow price of the turbine discharge bounds (Equation 4.6.1.6) provides information on the cost of a unit increase/decrease in the turbine capacity limits. When the constraint is binding, the shadow prices, in $/m^3-sec, represents the additional revenue/cost of relaxing/tightening the turbine limits from its current level by one unit, within the permissible range. Figure 6.42 illustrates variation of the shadow price among plants in the study. A positive cost indicates a decrease in revenues which results in lowering the maximum turbine limit, while a negative cost indicate an increase in profit resulting from lowering the minimum turbine limit. It can be noted that the LAJ and SON upper turbine bounds were binding for most hours in the study. The cost of LAJ turbine bound are much higher than other plants because LAJ turbine discharge is used twice (by BR and SON) after its release. Other plants (e.g., RUS, COM, PCN, SEV) exhibited lower cost for the upper and lower bounds.

ii. The Shadow Price of the Generation Production Function.

The shadow price of the generation production PWL function (Equation 4.6.1.12) provides information on the cost (in $/MWHr) of increasing production by one unit (also known in the industry as the plant's incremental cost (IC)), for each generating plant at each time step in the study. The value of IC and its permissible range depends on the hourly generation level of the plant in question and it depends on the energy conversion rate of the PWL segment. For this reason it can be noted in Figure 6.43 that IC varies from one hour to the next for most plants. It is highest when the plant is generating in proximity to its maximum limit and lowest otherwise. It can also be seen that, as the generation breakpoint in the PWL function depends on the plant's forebay level, the value of IC exhibits a slight decrease as the forebay level decreases (e.g., see variation of JHT IC as the forebay level fluctuate).

iii. The Shadow Price of the Plant Generation Bounds.

The shadow price of the plant generation bounds (Equation 4.6.1.13 and 4.6.5.6) provides information on the cost of a unit increase/decrease in generation bounds. When the constraint is binding, the shadow prices, in $/MWHr represent the revenue/cost of relaxing/tightening the generation limit from its current level by one unit, within the permissible range. This shadow price could probably be used to reflect the cost of generation outages. It could also be used to rank the order of outages in real-time operation. Figure 6.44 illustrates the variation of this shadow price for the 19 plants and for the duration of the study. The Figure also compares the system incremental cost (the shadow price of the load-resource balance equation) with the generation bounds price. It can be noted that the costs of the ALU and SON generation bounds exhibit similar behavior to the system incremental cost (which is slightly higher). Other plants show lower bound costs that behave in accordance with market conditions (i.e., high when plants are loaded at maximum generation levels for exports).

iv. The Shadow Price of the Mass-Balance Equation.

The shadow price of the storage mass-balance equation (Equation 4.6.1.10) provides information on the incremental cost of storage (ICS) in Mils/m^3, for each reservoir at each time step. Figure 6.45 illustrates the variation of ICS for each plant (for each plant's reservoir) included in the study. The value of ICS for hour 84 is shown next to the bar inside the chart, while the table to the right lists the MVW that were derived from Rbch, as described in Section 6.2.4. Three important observations can be made on this illustration. First, ICS is almost identical to MVW, which was derived from Rbch, the exceptions being, the ALU, LDR, SON, CMS, COM, ASH, SEV, and WAN. Second, when ICS is lower than the corresponding MVW, storage in the plant's reservoir increases (e.g., ALU, LDR, SON, ASH, and WAN). On the other hand, when ICS is higher than the derived MVW, storage decreases (e.g., CMS, COM, SEV). Third, for some plants, ICS slightly varies as the forebay levels fluctuates (e.g., JHT, SEV, WAN). Time constraints did not allow for full exploration of the behavior of ICS, and future research is needed on this important aspect of sensitivity analysis, since it could have significant operational and system modeling implications.

v. The Shadow Price of the Storage Bounds.

The shadow price of the storage bounds (Equation 4.6.1.11) provides information on the cost of a unit increase/decrease in the storage limits. When the constraint is binding, the shadow price, in \$/m^3 represents the revenue/cost of relaxing/tightening the storage limits from its current level by one unit, within the permissible range. This shadow price could probably be used to reflect the cost of imposing limits on the forebay levels for recreational or other purposes (e.g., logging operations). Figure 6.46 illustrates the variation of the shadow price of the storage bounds for the plants included in the study. It can be seen that the shadow price for most small reservoirs is above or below zero (e.g., RUS, SON, COM, LDR, JHT, PCN, SEV, and WAN), which reflects the fact that these reservoirs could easily reach their minimum or maximum storage limits. It should be noted that the storage limits in these reservoirs are operational, not physical limits. The limits are set by the Shift Engineer to reflect the desired operating levels for each reservoir.

vi. The Shadow Price of the Load-Resource Balance Equation.

The shadow price of the load-resource balance equation (Equation 4.6.5.2) provides information on the cost of increasing the system load by one unit, or the system incremental cost (SIC). Such valuable information derived from the optimization model can be used as indicators for the "Market Clearing Price" in planning spot trading schedules and in operating the system in real time. It can be seen in Figure 6.47 that SIC exhibits the following behavior. In export mode, it assumes the lower value of the two spot market prices when both tie lines are at their limits and when the system has no slack generating capacity. However, when slack system capacity exists, and when there are opportunities to export, but both the tie lines are at their limits, SIC value declines sharply by an amount equal to the maximum value of the shadow prices of the two tie line limits. In import mode SIC assumes the value of the marginal plant(s) in the system when the two tie lines are at their minimum limit. The marginal plant(s) is defined as the plant that has not reached it minimum or maximum generation limits, and that has the highest incremental cost. Figure 6.48 illustrates SIC behavior with respect to generation, exports, imports, tie line limits, and the system slack capacity. Further research is needed to fully explore the behavior of SIC in other different situations.

vii. The Shadow Price of the Regulating Margin Requirement.

The shadow price of the regulating margin requirement (Equation 4.6.5.7) provides information on the cost of a unit increase/decrease in the regulating margin requirement limit. When the constraint is binding, the shadow prices, in $/MWHr represents the revenue/cost of relaxing/tightening the regulating margin requirement. This shadow price, shown in Figure 6.47, could be used to reflect the cost of providing this service to the interconnected electric system in the WSCC, or alternatively it could be used as indicator of the cost of blackouts.

viii. The Shadow Price of the Tie Line Limits.

The shadow price of the tie lines capacity constraint (Equation 4.6.5.8) provides information on the cost of a unit increase/decrease in the tie line transmission capacity limits. When the constraint is binding, the shadow prices, in $/MWHr represents the revenue/cost of relaxing/tightening the tie lines capacity limits (or availability's) from its current level by one unit, within the permissible range. This shadow price is shown in Figure 6.47, and it could be used in real-time operations to determine the benefits of reserving additional transmission capcity to increase spot sales during favorable market conditions.

ix. The Shadow Price of the Fix Plant Generation Constraint.

The shadow price of the constraint that fixes a plant generation to the planned schedule (Equation 4.6.1.14) represents the cost of fixing the generation schedule in the model in $/MWHr for each time step in the study. This shadow price could be used to cost operational restrictions on plant generation (e.g., fixing the PCN generation during ice formation in the Peace River).

x. The Shadow Price of the Spill Bounds.

The shadow price of the spill discharge bounds (Equation 4.6.1.7) provides information on the cost of a unit increase/decrease in the spill limits. When the constraint is binding, the shadow price, in $\$/m^3/sec$ represent the revenue/cost of relaxing/tightening a spill limit from its current level by one unit, within the permissible range. This shadow price can probably be used to reflect the cost of environmental, regulatory and non-power spill releases.

xi. The Shadow Price of the Plant Discharge Bounds.

The shadow price of the plant discharge bounds (Equation 4.6.1.9) provides information on the cost of a unit increase/decrease in the plant discharge limits. When the constraint is binding, the shadow price, in $/m^3/sec represent the revenue/cost of relaxing/tightening a plant discharge limit from its current level by one unit, within the permissible range. This shadow price could probably be used to reflect the cost of imposing a plant's total discharge limit aimed at satisfying environmental, regulatory or non-power requirements.

xii. The Shadow Price of the Thermal Generation Production Function.

The shadow price of the thermal power generation production function (Equation 4.6.5.3) provides information on the thermal incremental cost in $/MWHr, for each thermal generating plant at each time step. The shadow price in this constraint depends on the slope of the segment of the PWL production function.

xiii. The Shadow Price of the Thermal Generation Bounds.

The shadow price of the thermal generation bounds (Equation 4.6.5.5) provides information on the cost of a unit increase/decrease in the thermal generation limits. When the constraint is binding, the shadow price, in $/MWHr represent the revenue/cost of relaxing/tightening a generation limit from its current level by one unit, within the permissible range. This shadow price could be used to cost thermal outages.

xiv. The Shadow Price of the Fix Storage Constraint.

The shadow price of the constraint that fixes the storage level at the last time step in the study to a predefined level (Equation 4.6.5.9) provides information on the cost of fixing the storage level at the last time step in the study, in $/m^3.

In addition to the constraints' shadow prices, the upper and lower bounds along with the reduced costs (opportunity costs) of all the variables in the model are written to sensitivity analysis output data files, and are available for analysis in the future.

Although STOM users do not currently use all of the sensitivity analysis information, due to the overwhelming amount of information that they currently have to process, it is planned to make use of it in future phases of its implementation.

Information from sensitivity analysis is very extensive, and each optimization run could require hours of manual analysis to fully understand system behavior. For this reason, it is believed that to make full beneficial use of this information for real-time generation and marketing operations would require automation of interpretation of the sensitivity analysis information. Such automation, however, would require the use of predefined rules of logic to interpret the meaning of sensitivity analysis data -a function that is very well suited for expert systems, as highlighted by Greenberg in his series of articles on the subject (Greenberg, 1993).

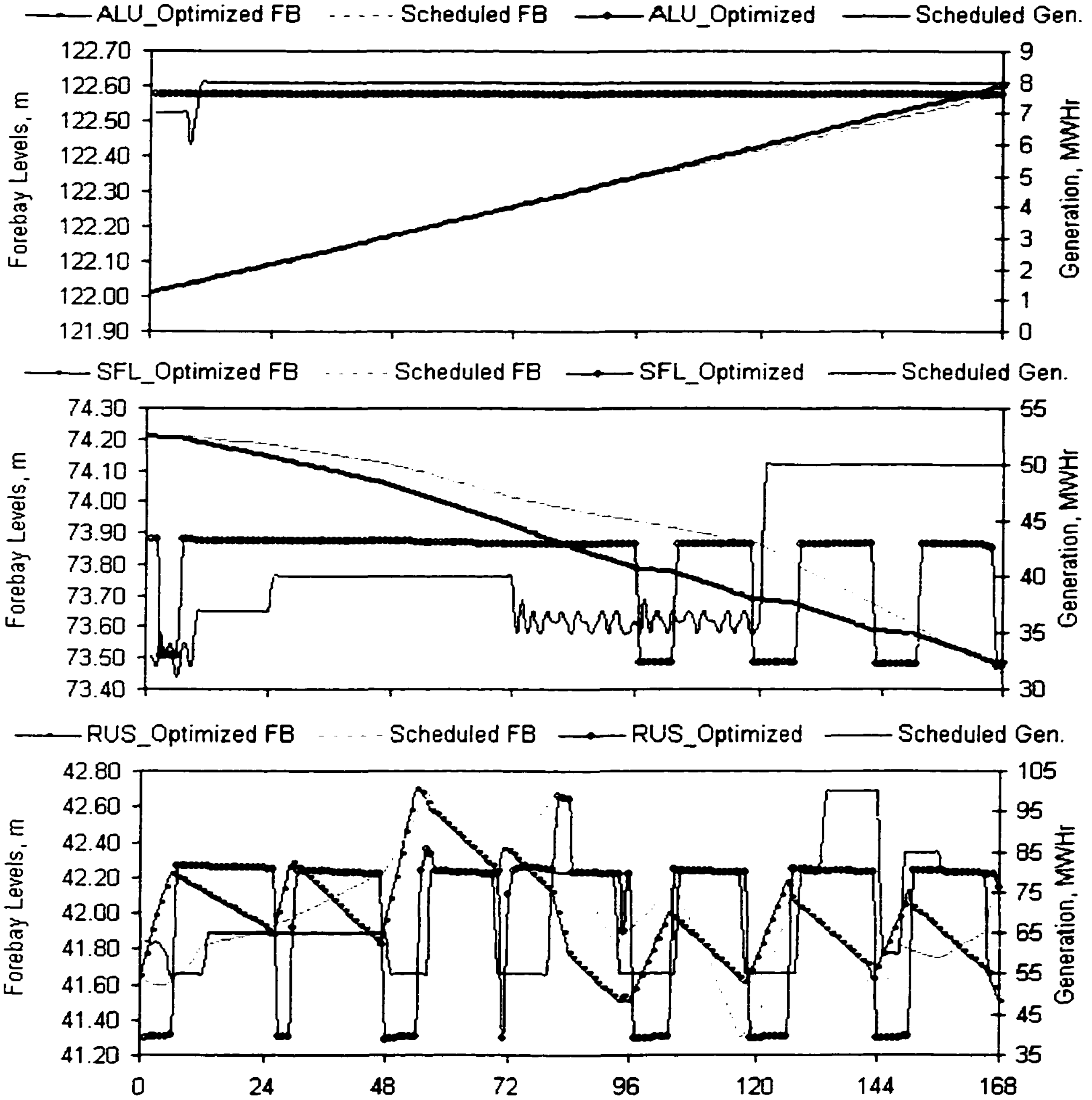


Figure 6.35. Planned and Optimized Generation and Forebay Schedules: Stave Falls River System.

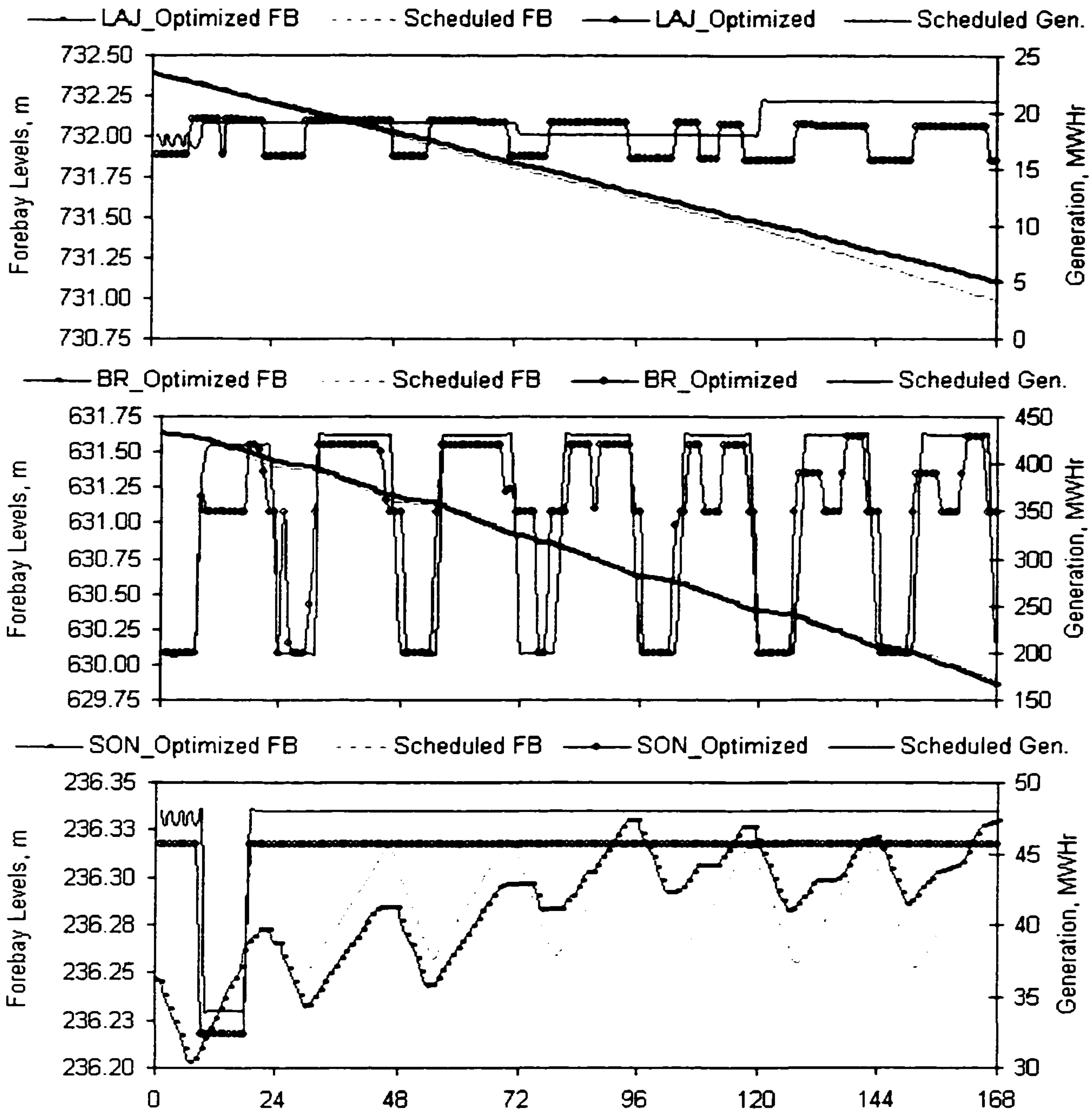


Figure 6.36. Planned and Optimized Generation and Forebay Schedules: Bridge River System.

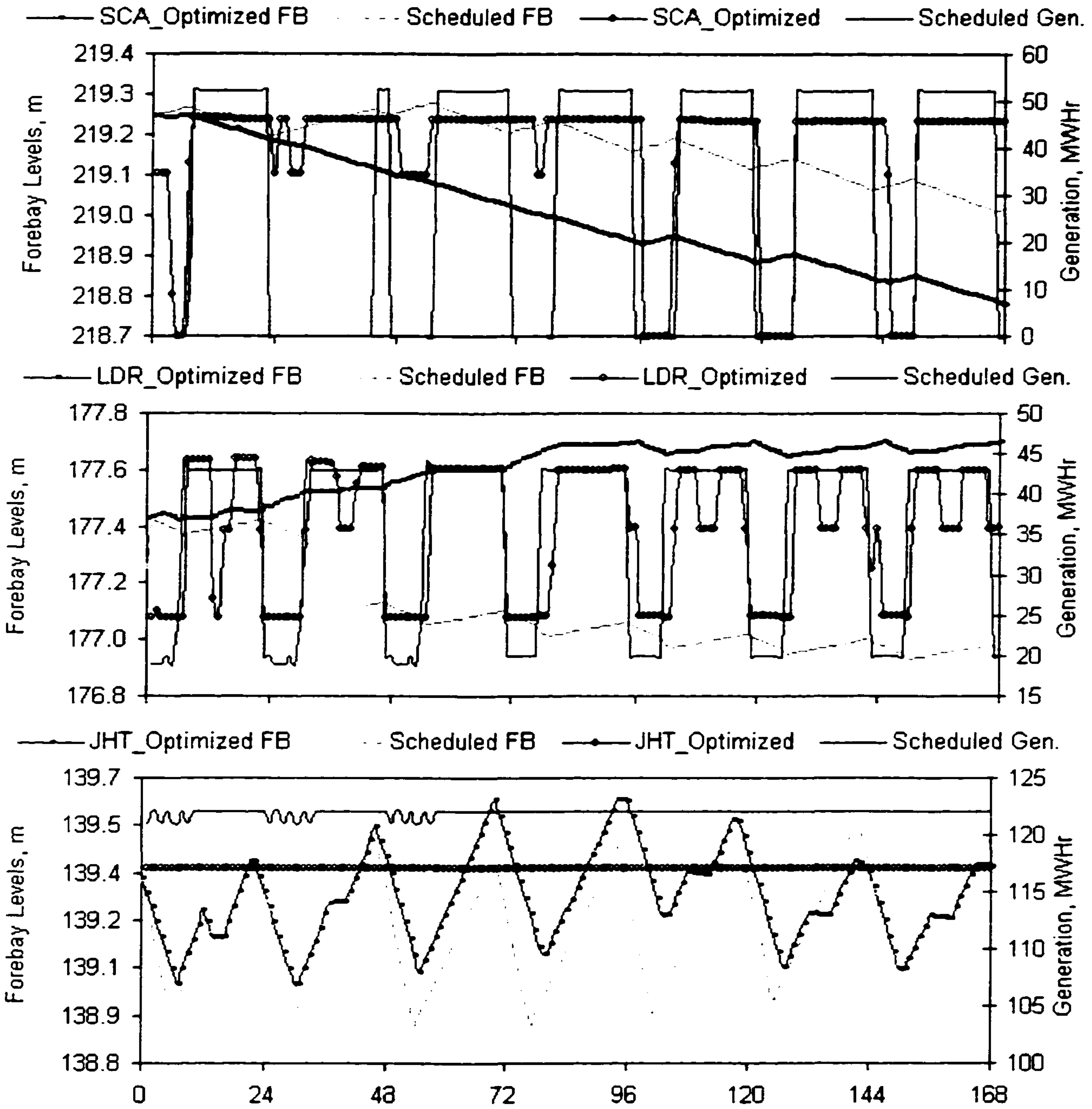


Figure 6.37. Planned and Optimized Generation and Forebay Schedules: Campbell River System.

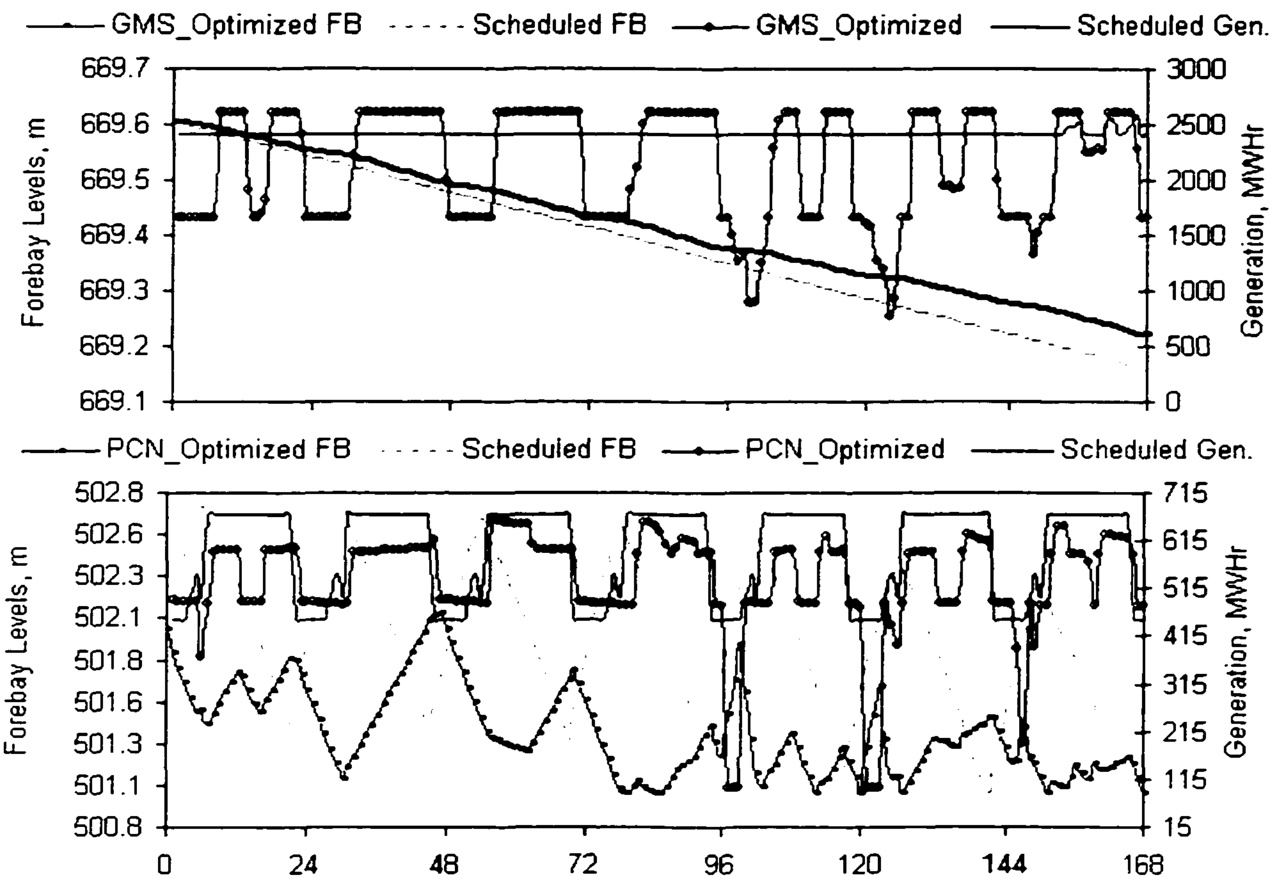


Figure 6.38. Planned and Optimized Generation and Forebay Schedules: Peace River System.

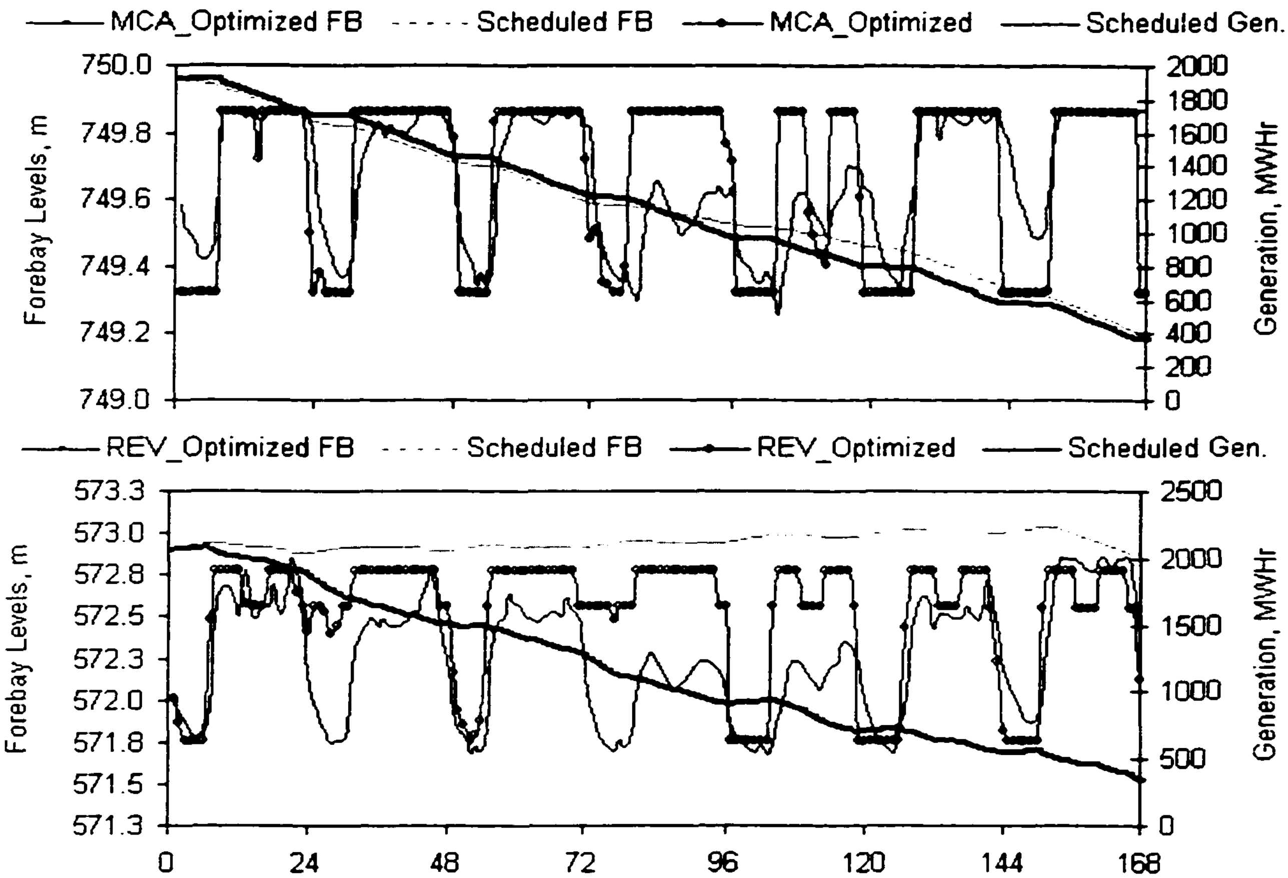


Figure 6.39. Planned and Optimized Generation and Forebay Schedules: Columbia River System.

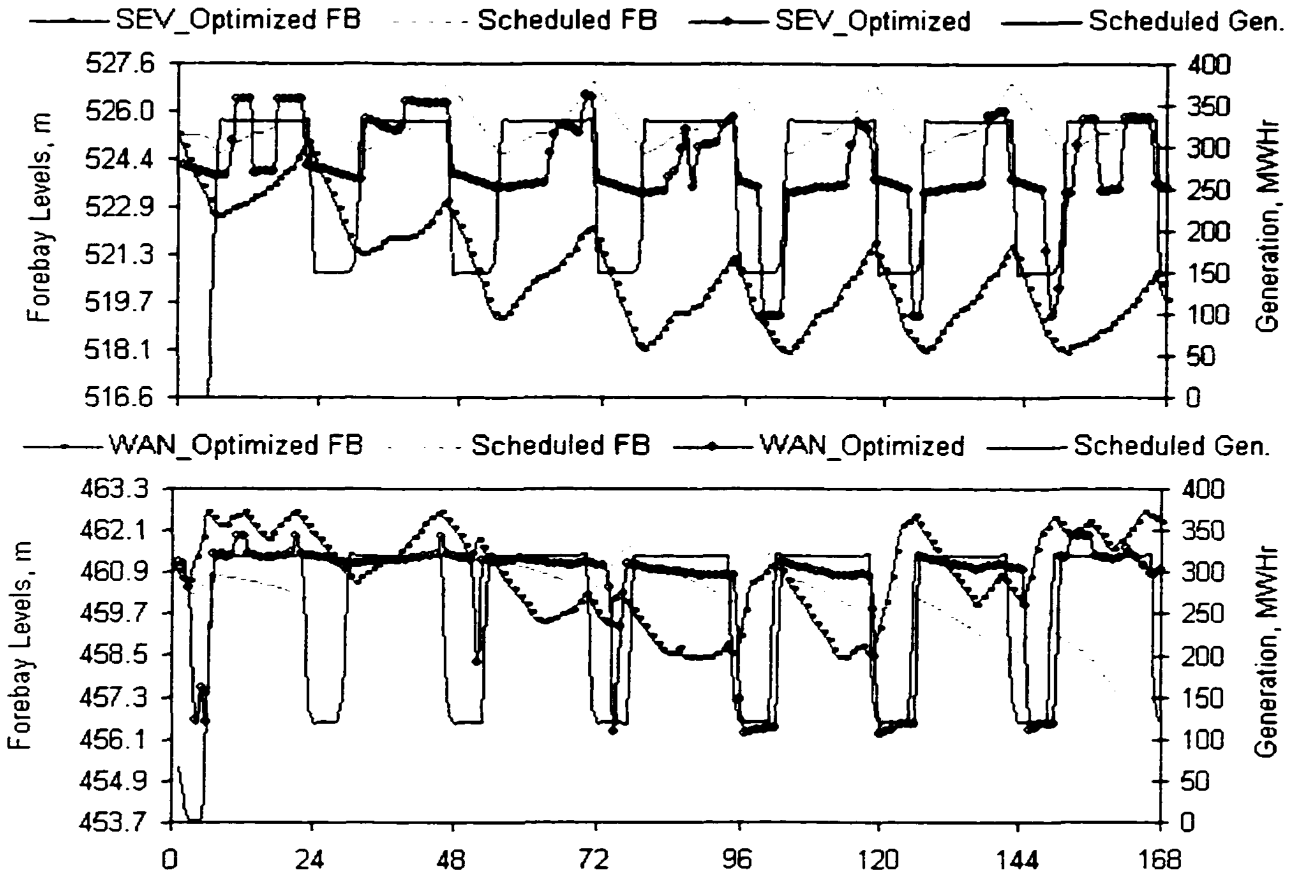


Figure 6.40. Planned and Optimized Generation and Forebay Schedules: PendOreille River System.

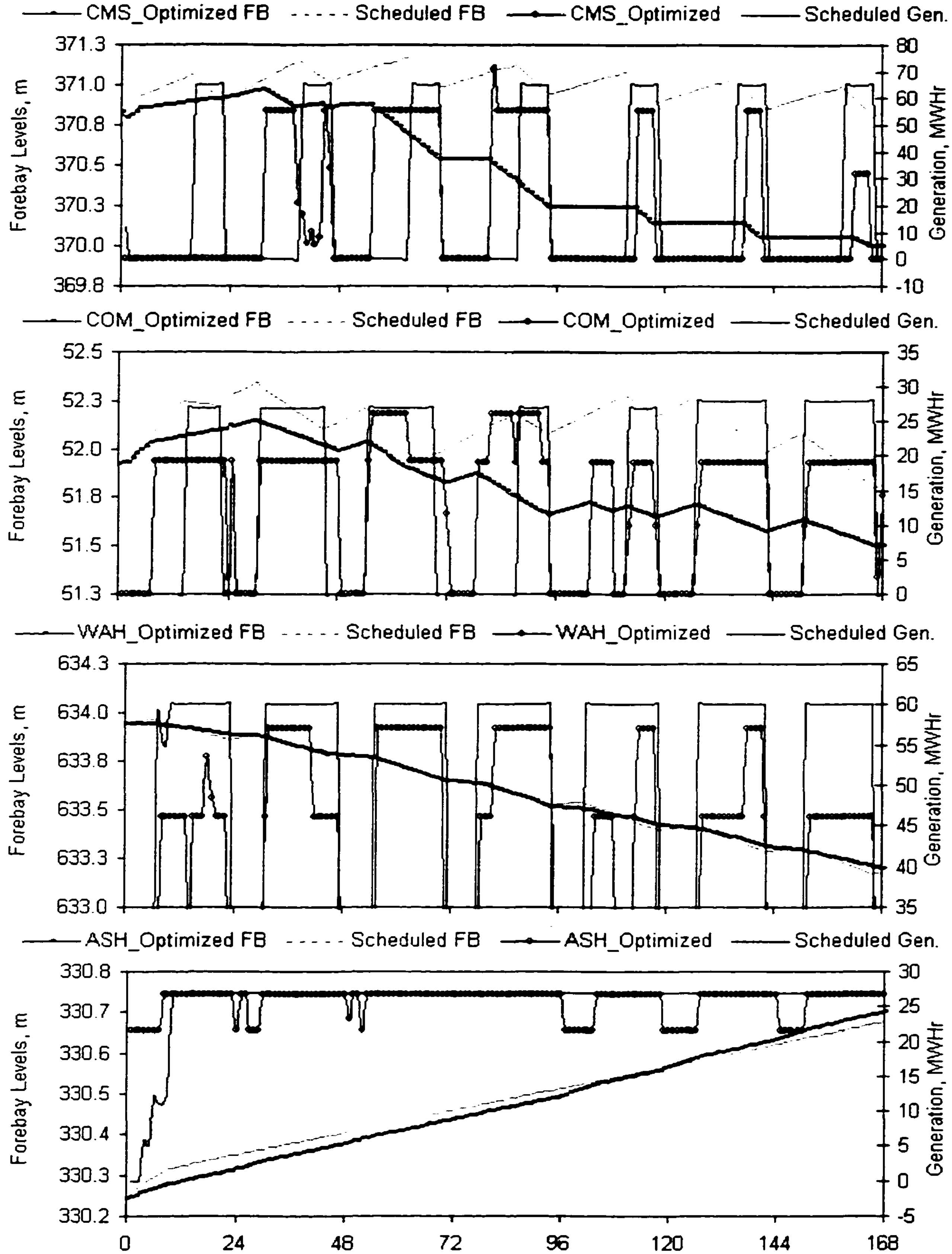


Figure 6.41. Planned and Optimized Generation and Forebay Schedules: Cheakamus, Clowhom, Wahleach and Ash River Systems.

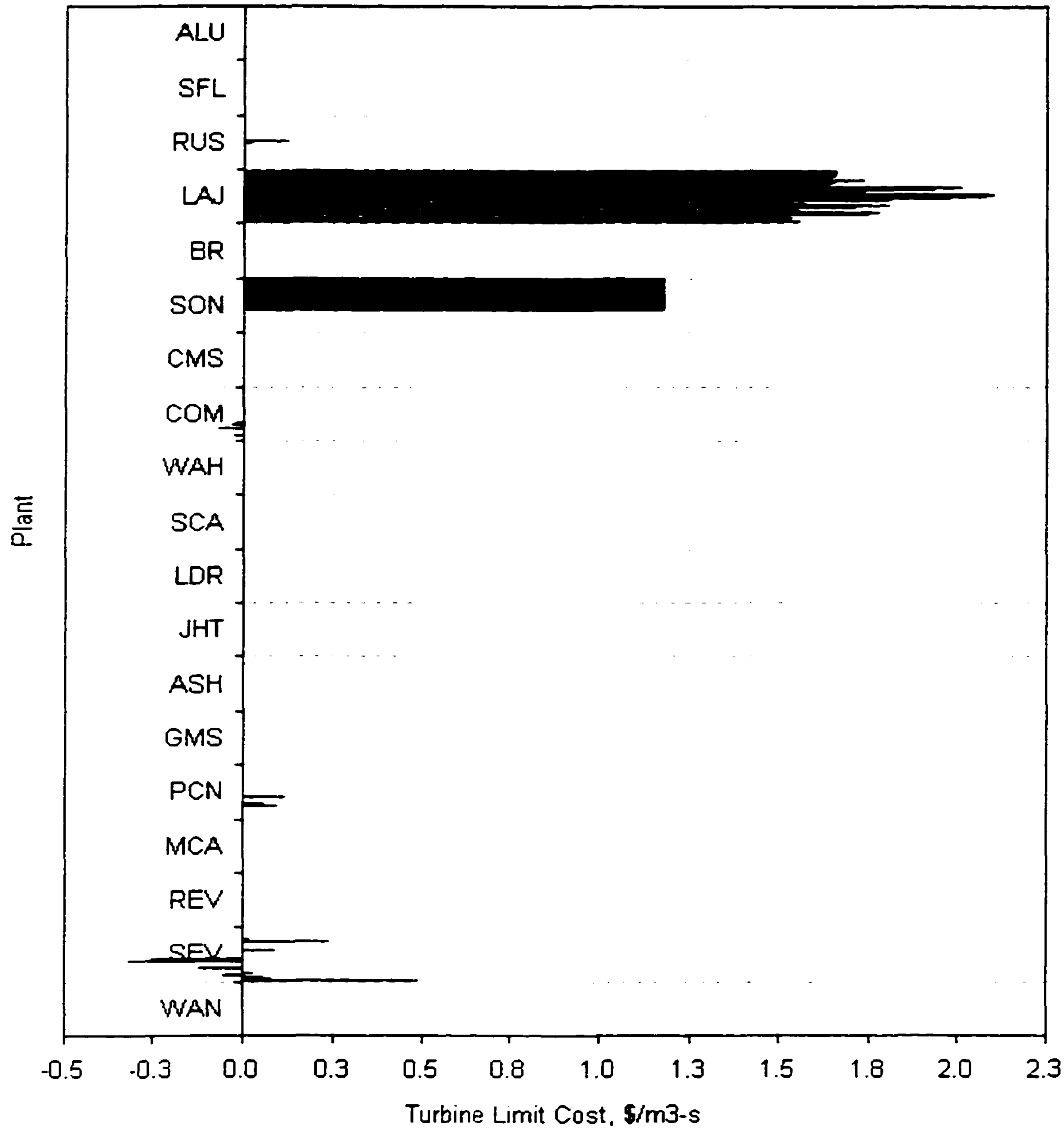


Figure 6.42. Turbine Discharge Limit Cost.

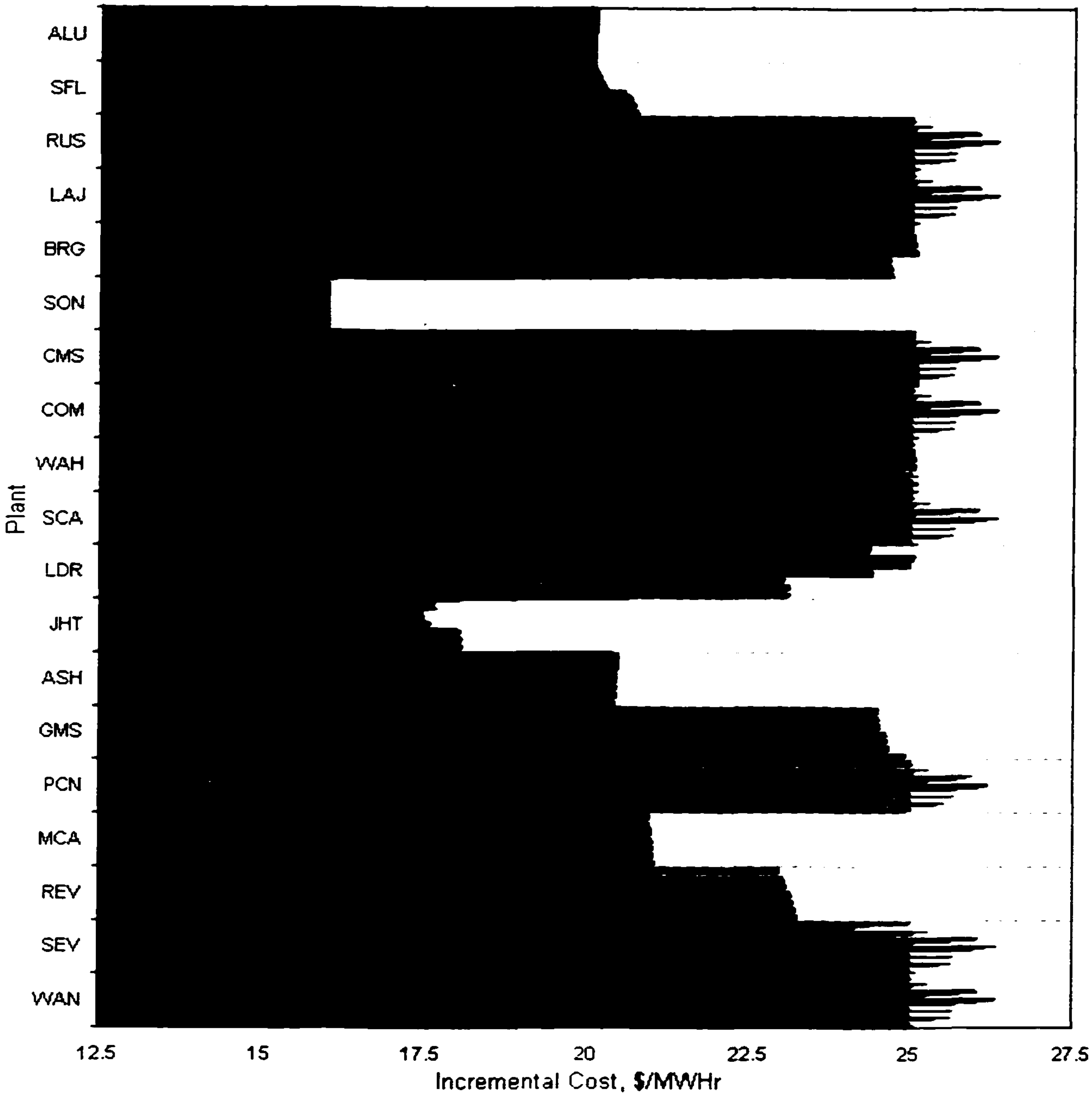


Figure 6.43. Plant's Incremental Cost of Generation.

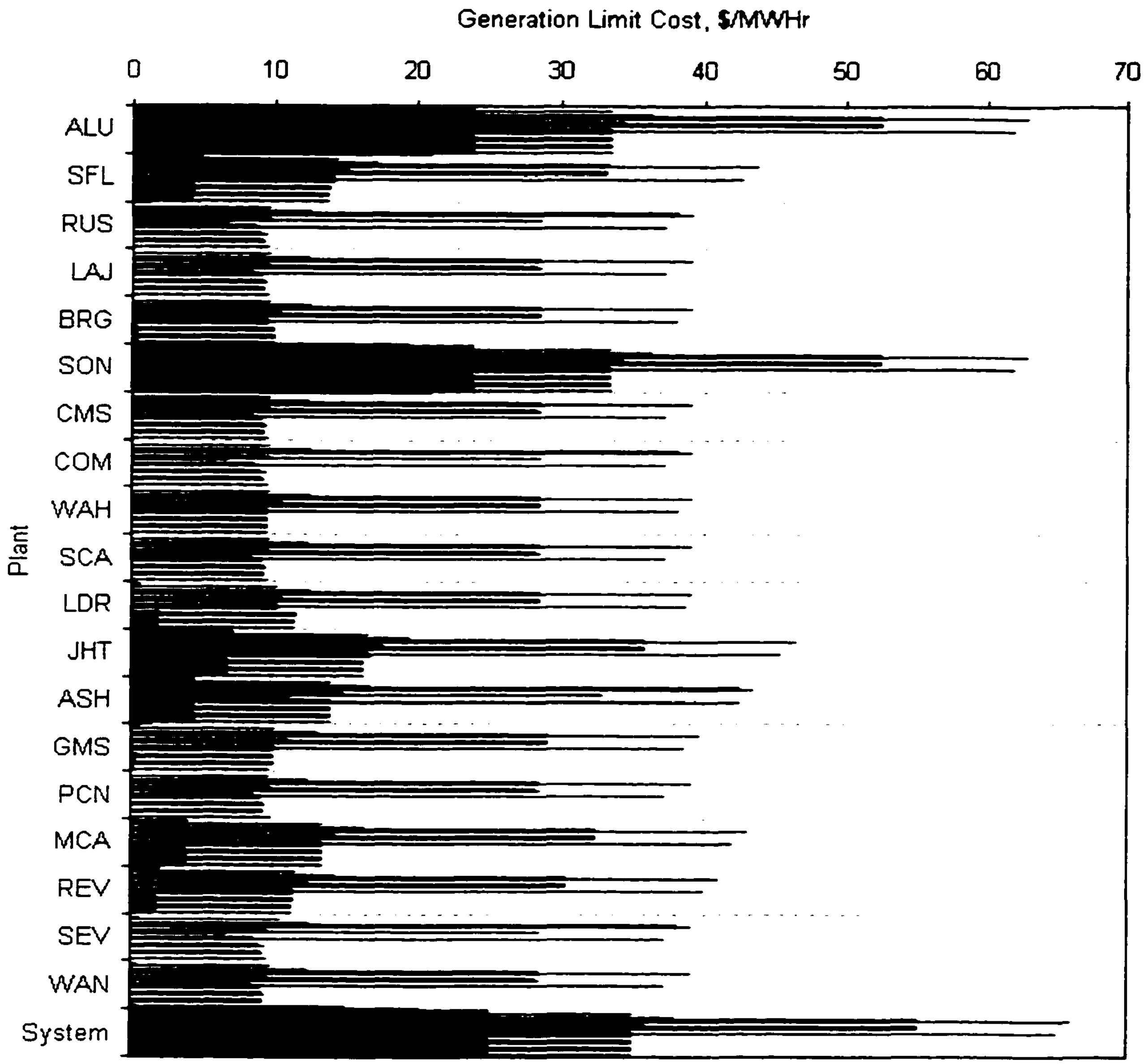
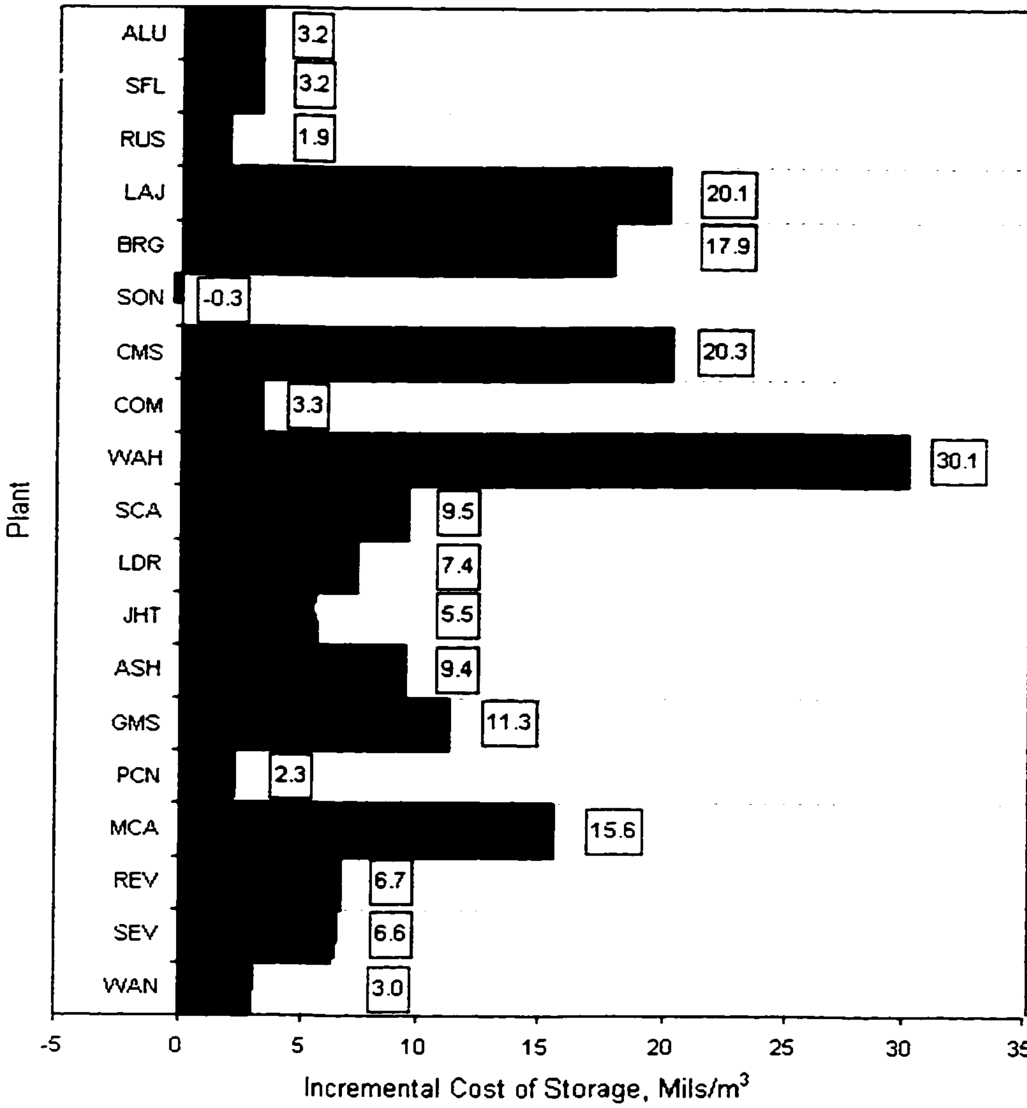


Figure 6.44. Plant's Generation Limit Cost.



Plant	MW
ALU	5.5
SFL	3.2
RUS	1.8
LAJ	20.1
BR	17.9
SON	2.4
CMS	13.7
COM	2.5
WAH	30.1
SCA	9.5
LDR	7.5
JHT	5.7
ASH	11.8
GMS	11.3
PCN	2.1
MCA	15.6
REV	6.7
SEV	6.3
WAN	3.1

Figure 6.45. Incremental Cost of Water Storage.

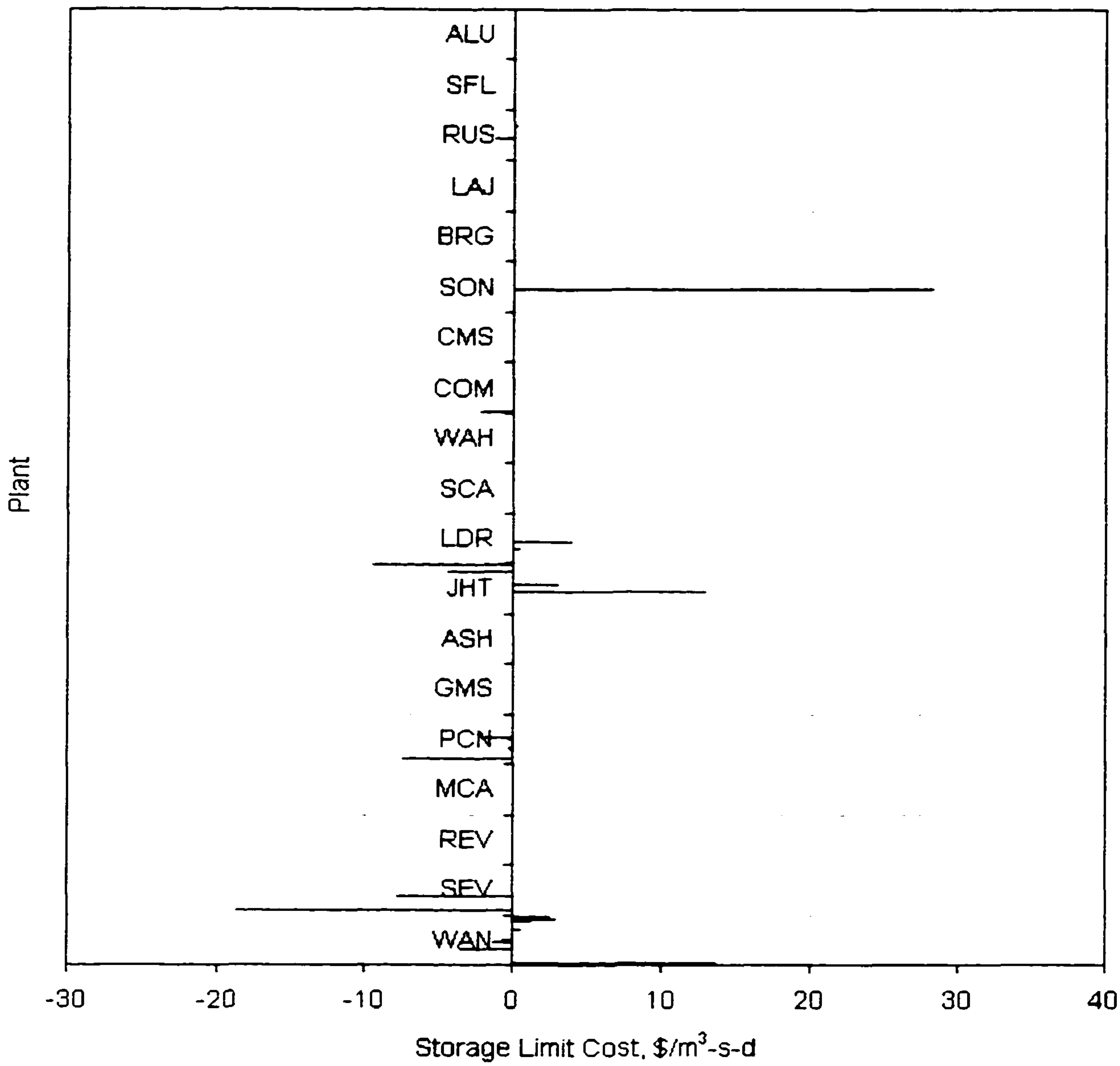


Figure 6.46. Storage Limits Cost.

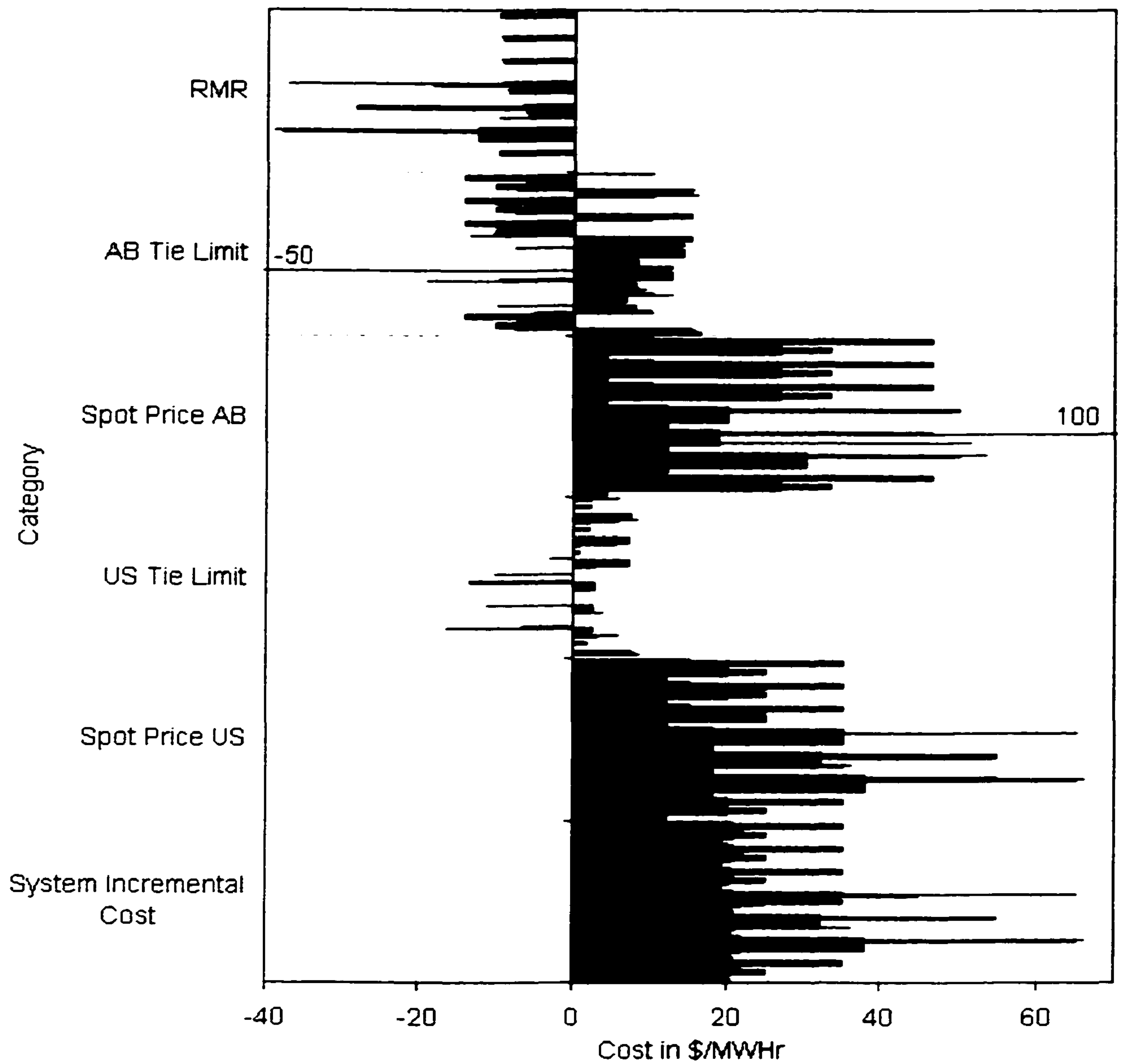


Figure 6.47. System Incremental Cost, Spot Market Prices, Tie Line Limits Cost, and Regulating Margin Cost.

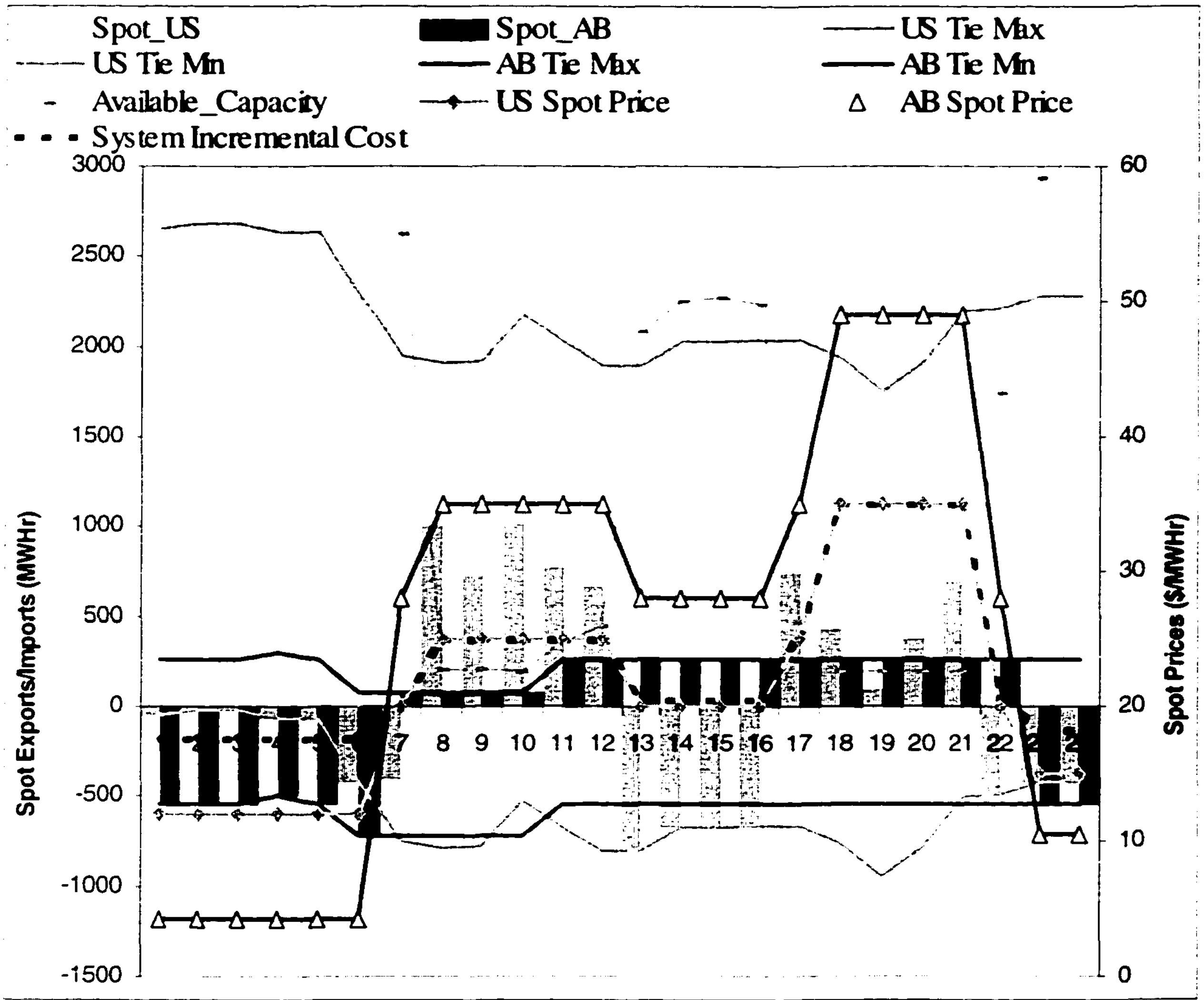


Figure 6.48. Behavior of SIC with Generation, Exports and Imports, Tie Line Limits, and System Slack.

6.3 PERFORMANCE OF THE DECISION SUPPORT SYSTEM

This section presents a summary of performance of the decision support system. It starts with the overall performance of the solution algorithm and includes discussion on the behavior of the generation and reservoir schedules in the solution algorithm. Then performance of the Simplex Primal and Dual algorithms is compared.

6.3.1 Performance of the Solution Algorithm

i. Meeting User's Functional Requirements

One of the user's functional requirements specified that the decision support system should complete the study for ten plants and for 168 hours in less than three minutes. STOM met, and even exceeded, this functional requirement. The total computer time it takes to run the overall solution algorithm for 10 plants, for 168 hours, on a 450 MHz, with 250 Mega Byte of Random Access Memory and Windows NT operating environment, is about 110 seconds (see Figure 6.49), or about 61% of the "allowable" time.

Figure 6.50 illustrates the breakdown of the total computer time required to execute the steps in the solution algorithm outlined in Section 5.1.5, and running the Maximize the Efficiency objective function. It can be noted that solving the optimization problem for ten plants and for 168 hours, which consisted of 11572 variables and 6888 constraints, required about 55% of the computing time, while the simulation runs took about 22%, data transfer took about 16%, and initialization and writing output information took about 6%, of the total solution time.

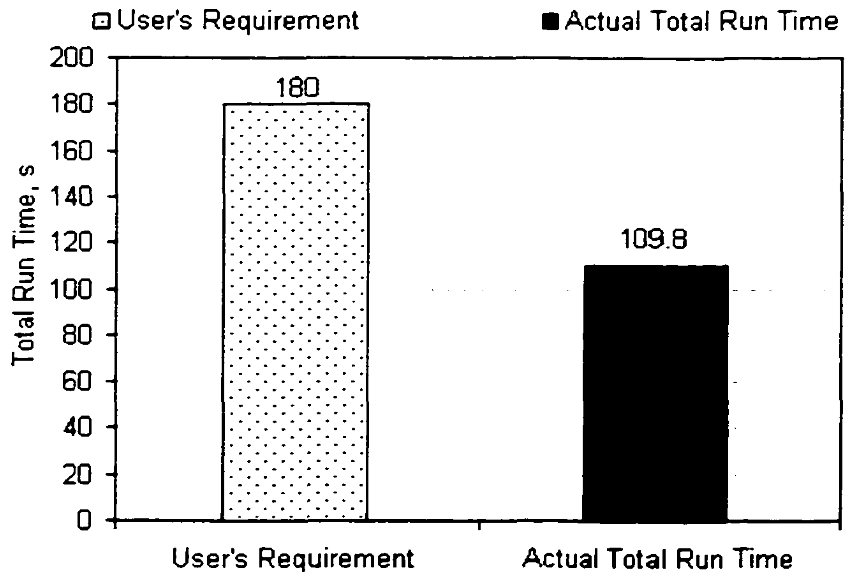


Figure 6.49. Total Run Time: User's Requirements and Actual Performance.

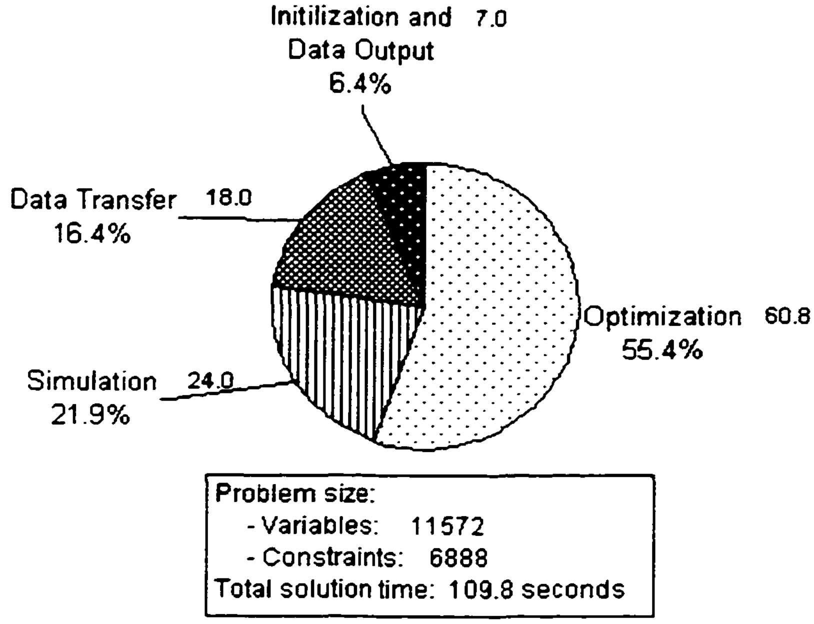


Figure 6.50. CPU Time of the Solution Steps.

The solution algorithm iterates for convergence of all the plant's forebay levels, and for this reason several iterations are carried out (see Section 5.1.5 for details). The total difference in forebay levels is calculated by taken the sum of the absolute difference between forebay levels, for each plant and for each time step, in the previous and the current optimization iteration, except for the first run where the total forebay difference is calculated as the difference between the pre-scheduled and the optimized schedule. Figure 6.51 illustrates the value of the objective function and total difference in forebay level for this study. It can be seen that seven iterations were required for convergence. The value of the objective function in the first iteration was low, while the total forebay difference was high. The second iteration improved on the value of the objective function. It, however, slightly over estimated its value. In the third to fifth iterations the value of the objective function and the total forebay difference declined. In the sixth iteration the value of the objective function and the forebay difference increased. Finally, in the seventh iteration both the objective function and the forebay level stabilized, and the convergence criteria was met.

Figure 6.52 compares the computer time it took to run the optimization and simulation models in each iteration. In the first iteration, the Simplex Primal algorithm was used, while in the second to sixth iterations the Barrier algorithm was used, and in the final iteration, the Simplex Dual algorithm was used. It can be noted that the first optimization run took about 70% more computer time than the average for the other optimization runs. The reason for the decline in computer time needed to run the second to last optimization runs can be attributed to two main factors. First, the second to sixth optimization runs used the fast CPLEX Barrier (Primal/Dual) algorithm. Second, the second to sixth optimization runs used results of previous runs for the variable values as their initial conditions. In the seventh iteration, using results of the sixth run, the Simplex Dual algorithm outperformed the Barrier algorithm by about 14%

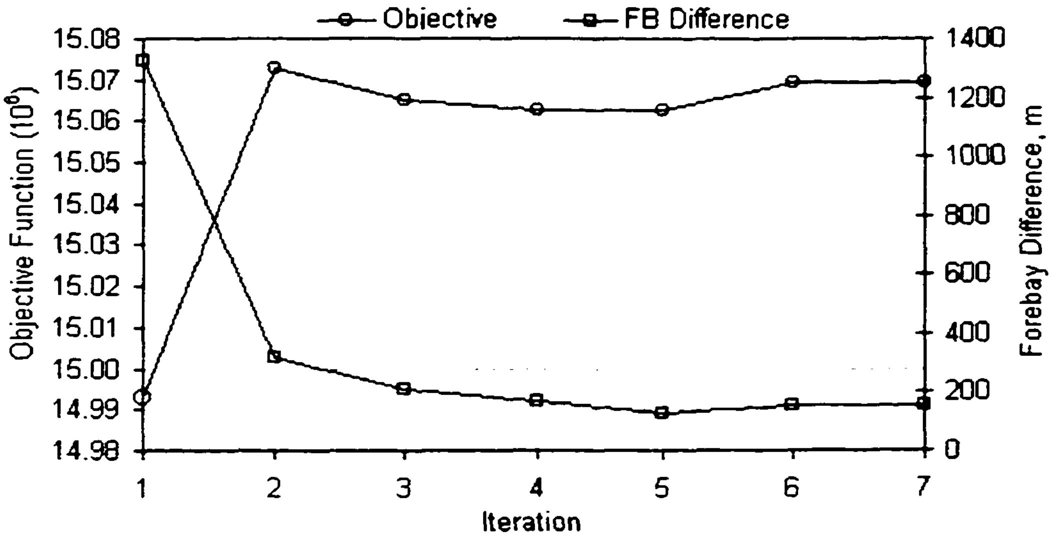


Figure 6.51. Convergence of the Objective Function and Forebay Difference.

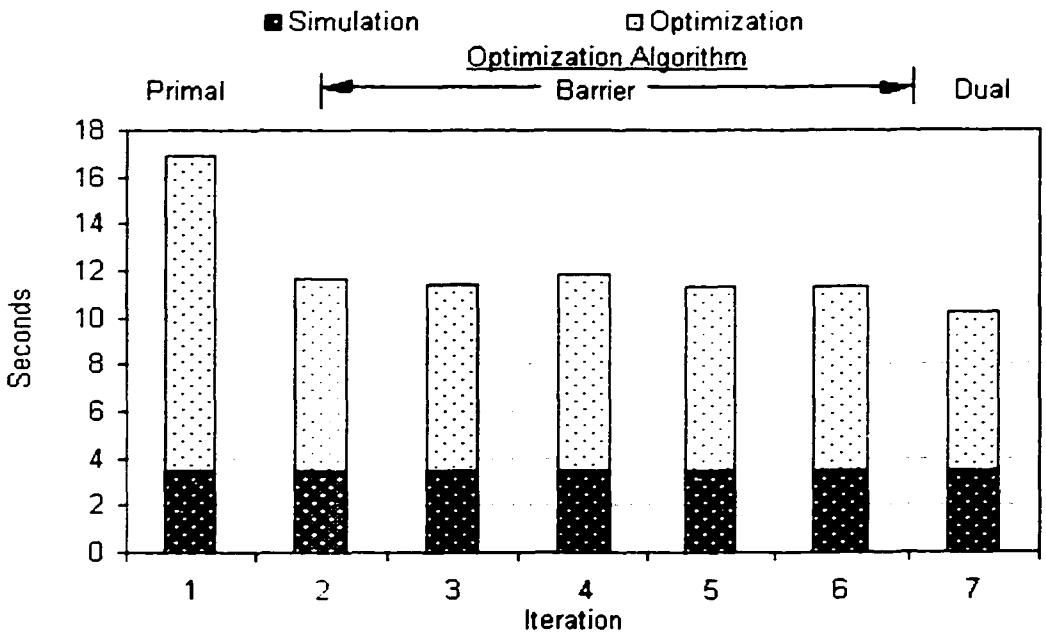


Figure 6.52. Variation of Computer Time to Run the Simulation/Optimization Models in Iterations.

Several features of the CPLEX Solver and the AMPL modeling language were used .to reduce the original problem size (number of variables and constraints), and to accelerate the solution algorithm. These included the use of CPLEX Presolver and Aggregator routines, and the AMPL direct substitution method. CPLEX Presolve reduces the number of columns and rows in the problem by presolving the problem and eliminating redundant constraints. The Aggregator looks for opportunities to eliminate variables and rows using substitution. The AMPL direct substitution method allows for dependent variables to be directly substituted in the model, which to some extent is similar to the Aggregator routine in CPLEX. In this study, CPLEX Presolve and Aggregator eliminated 37800 constraints and 31080 variables, while AMPL direct substitution eliminated 2520 variables. The use of CPLEX Presolve and Aggregator routines significantly improved the performance of the solution algorithm, while the AMPL direct substitution method allowed dynamic formulation of STOM's optimization models. The number of variables and constraints eliminated by the Presolve and Aggregator are significant which could lead one to think that the optimization model was not well structured. However, it should be realized that the optimization models were originally formulated to be generalized to the greatest extent possible, with the inevitable consequence of having many redundant variables and constraints. The routines provided by the CPLEX and AMPL systems thus facilitate efficient solution of generalized models such as STOM, and this shows the advantages of using efficient and robust commercial solvers.

ii. Variation of Performance with Size of the Optimization Problem

A key determinant of the time it takes to solve an optimization problem is its size. The number of variables and number of constraints in a problem measure the size of the optimization problem, and depend on the number of plants and reservoirs modeled and on the number of time steps in the study.

Several tests were carried out to investigate the effect of varying the number of time steps on the solution algorithm. The optimisation studies were carried out using the same set of input data, for 19 plants, and for the Maximize the Efficiency objective function. A summary of the tests results is given in Table 6.8, and illustrated in Figure 6.53.

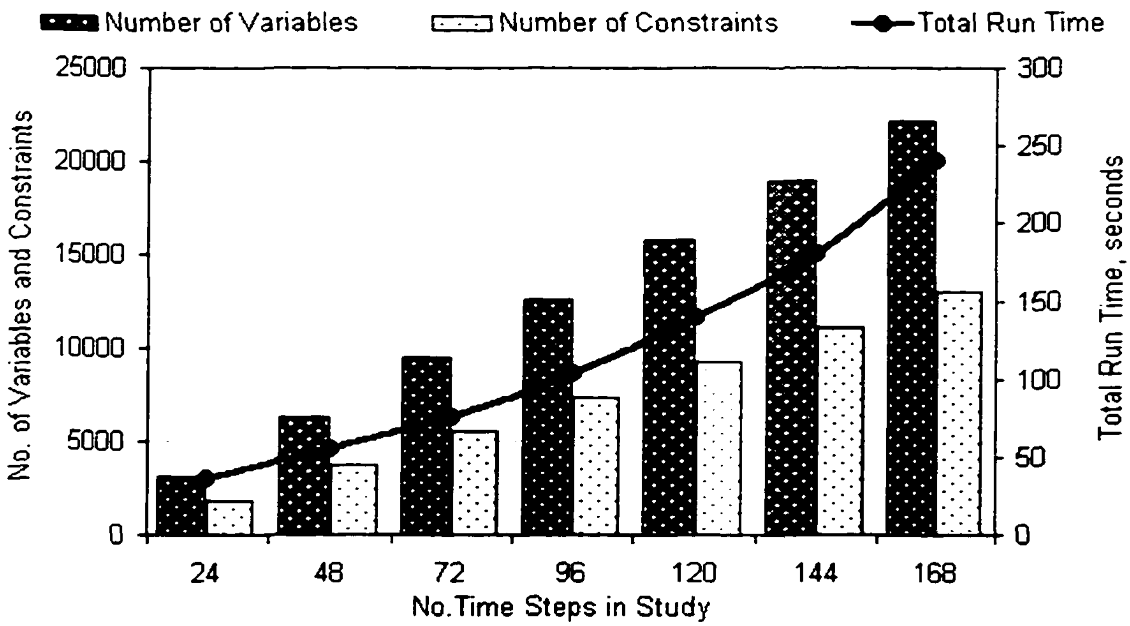
It can be noted in Figure 6.53.a that as the number of time steps increase, the size of the optimization problem and the total computer time needed to solve it increases. It can also be seen that while the size of the problem grows linearly, the time needed to solve the optimisation problem increases exponentially. For instance, it takes about 30-times more CPU time to solve a 7-times larger optimisation problem. Figure 6.53.b compares the number of the Simplex Primal and Dual iterations needed to solve the optimisation problem. It is interesting to note that the number of the Primal Simplex iterations (and CPU time) needed to solve the initial problem increases rapidly with the size of the problem.

Figure 6.53.c shows a breakdown of the total computer time needed to complete the optimisation study. It can be noted that most of the additional computer time needed to complete the study was taken by the optimisation runs, while simulation and other processes increased marginally. Figure 6.53.d shows the breakdown of computer time needed to run the optimisation model. It can be noted that the time needed to run the initial Primal iteration grows rapidly as the problem becomes larger and that the runs that used the Barrier algorithm (average of 5 iterations for each study) constituted a large percentage of the total optimisation computer time needed for optimisation. Finally, Figure 6.53.e shows the total stored energy

gain and the percentage gain for each study. It can be seen that as the study duration increased the total gain also increased. However, due to low load during the weekend (hours 24-72) the gain as a percentage slightly declined for periods above 120 hours. The main reason for the decline is due to low load (and generation) levels during the weekend and to high load levels on Monday and Tuesday. As discussed in Section 6.2.2, gain is highest when the system has some flexibility (i.e., when total system generation is neither at its lowest or its highest levels).

Table 6.8. Variation of Performance of the Solution Algorithm with Optimization Problem Size for Maximize the Efficiency Objective Function.

Measure	Study Duration (hour)						
	24	48	72	96	120	144	168
Number of Variables	3134	6294	9450	12594	15774	18954	22146
Number of Constraints	1848	3696	5544	7392	9240	11088	12936
Total Run Time (s)	36	55	75	103	139	180	240
Data Trasfer (s)	18	18	18	18	18	18	18
Initialization and Data Output (s)	6	6.2	6.5	6.8	7	7.5	8
Simulation (s)	6	14	17	23	30	35	51
Optimization (s)	6	17	33	55	84	120	163
Simplex Primal Iterations	2156	4535	6797	9382	13044	15811	19102
Simplex Dual Iterations	547	982	1919	4091	3320	4134	6643
stored Energy Gain MWHr	843	1786	2638	4008	5352	6139	6742
%Gain	0.59	0.64	0.63	0.75	0.81	0.77	0.71



a. Variation of Number of Variables, Constraints, and Total Run Time

Figure 6.53. Variation of Performance with the Size of the Optimization Problem.

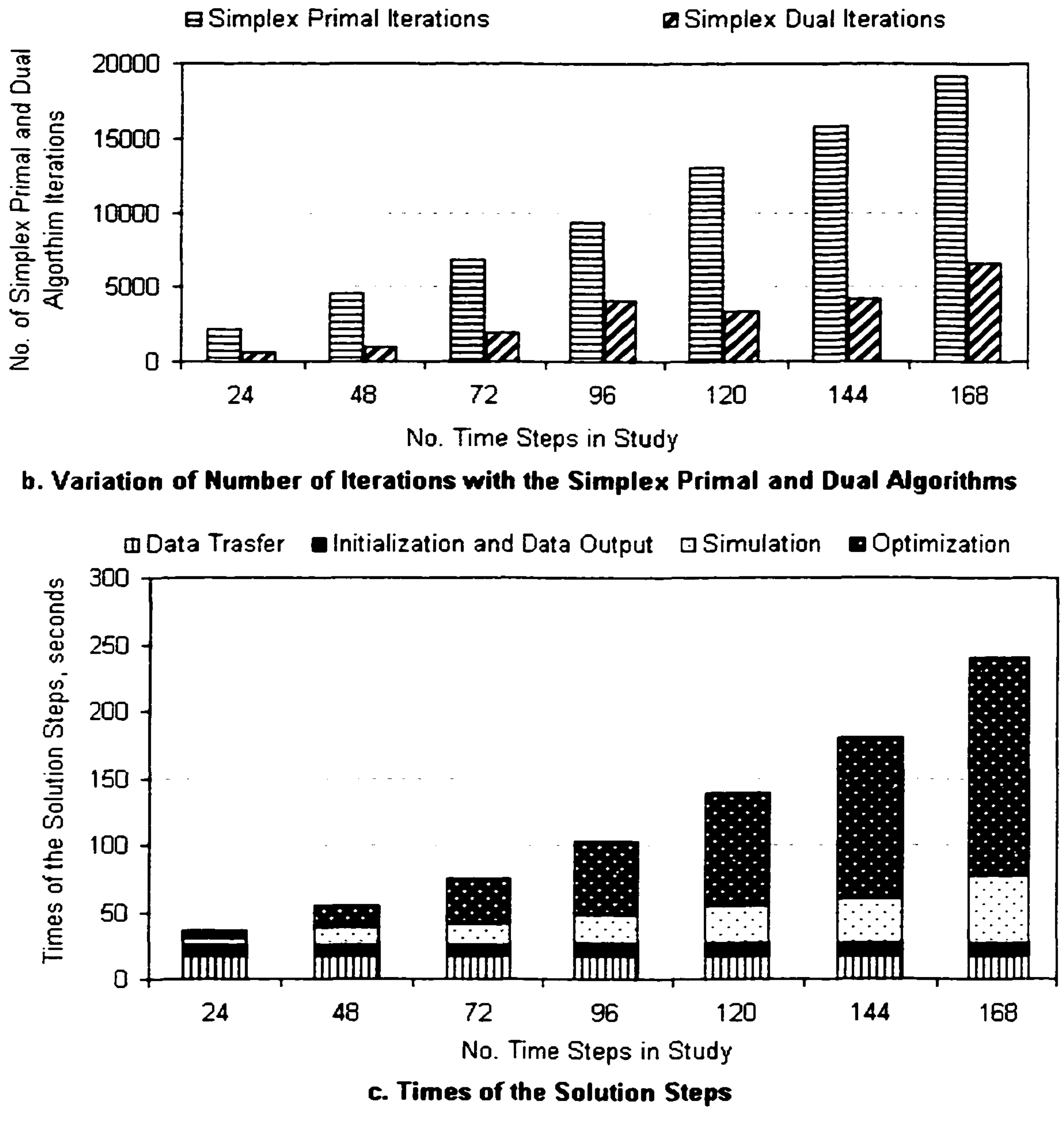
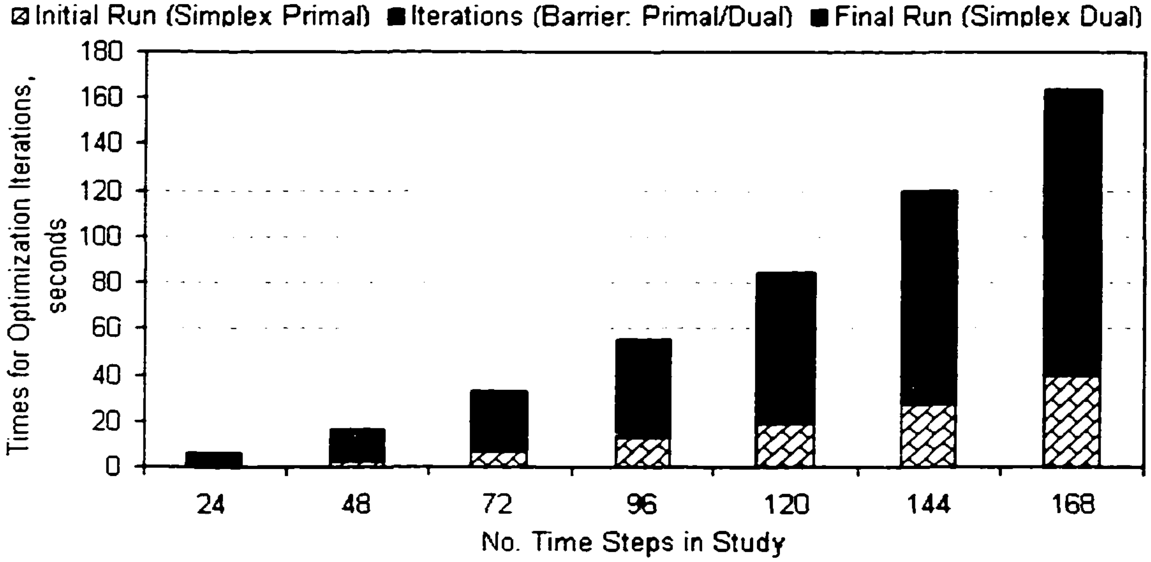
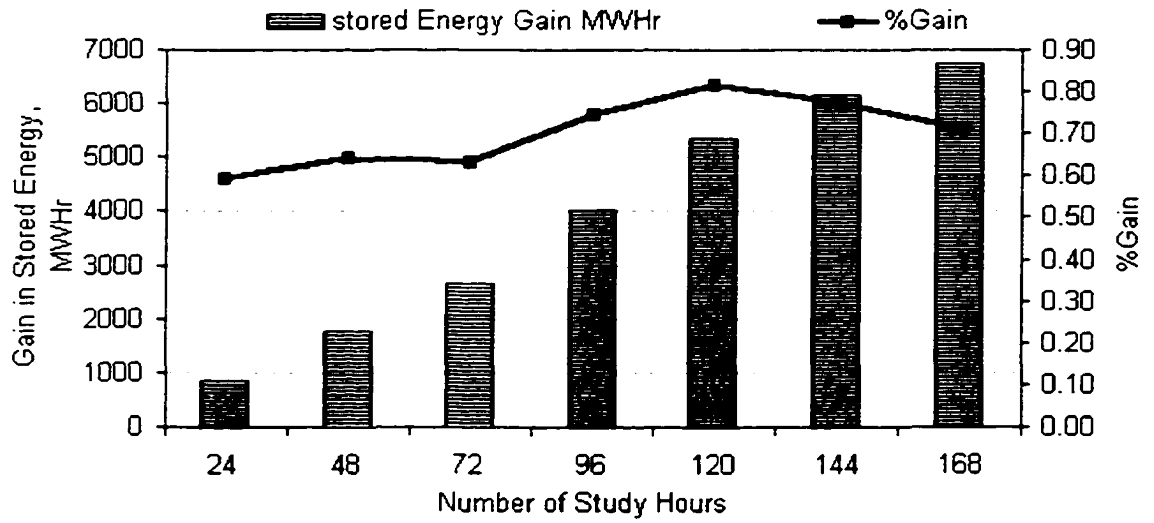


Figure 6.53. Variation of Performance with the Size of the Optimization Problem.



d. Times of the Optimization Iterations



e. Variation of Gain and % Gain with No. of Time Steps in Study

Figure 6.53. Variation of Performance with the Size of the Optimization Problem.

iii. Convergence of STOM Optimization Models

Figure 6.54 compares the forebay convergence of STOM optimization models for the different objective functions but with the same input data. It can be noted that Maximize the Profit objective function yielded the lowest forebay difference among the four objective functions. The main reason for this behavior is that the generation schedule derived by this objective function usually loads the plants at their peak efficiency levels as discussed in Section 6.1. In contrast, the value of the Maximize Profit objective function varied more than the other objective functions, and this can be attributed to changes in plants generation levels as the forebay levels change from one iteration to the next. It can also be noted that the behavior of forebay convergence for the Maximize Efficiency and the Minimize the Value of Water Used objectives are similar, which can be attributed to the similar structure of these two optimization models. It can also be noted that the forebay difference for Maximize Value of Production objective function converges much more quickly than other objective functions, probably because, in this model, the plants' forebay levels are constrained to meet the scheduled forebay levels at the last time step in the study.

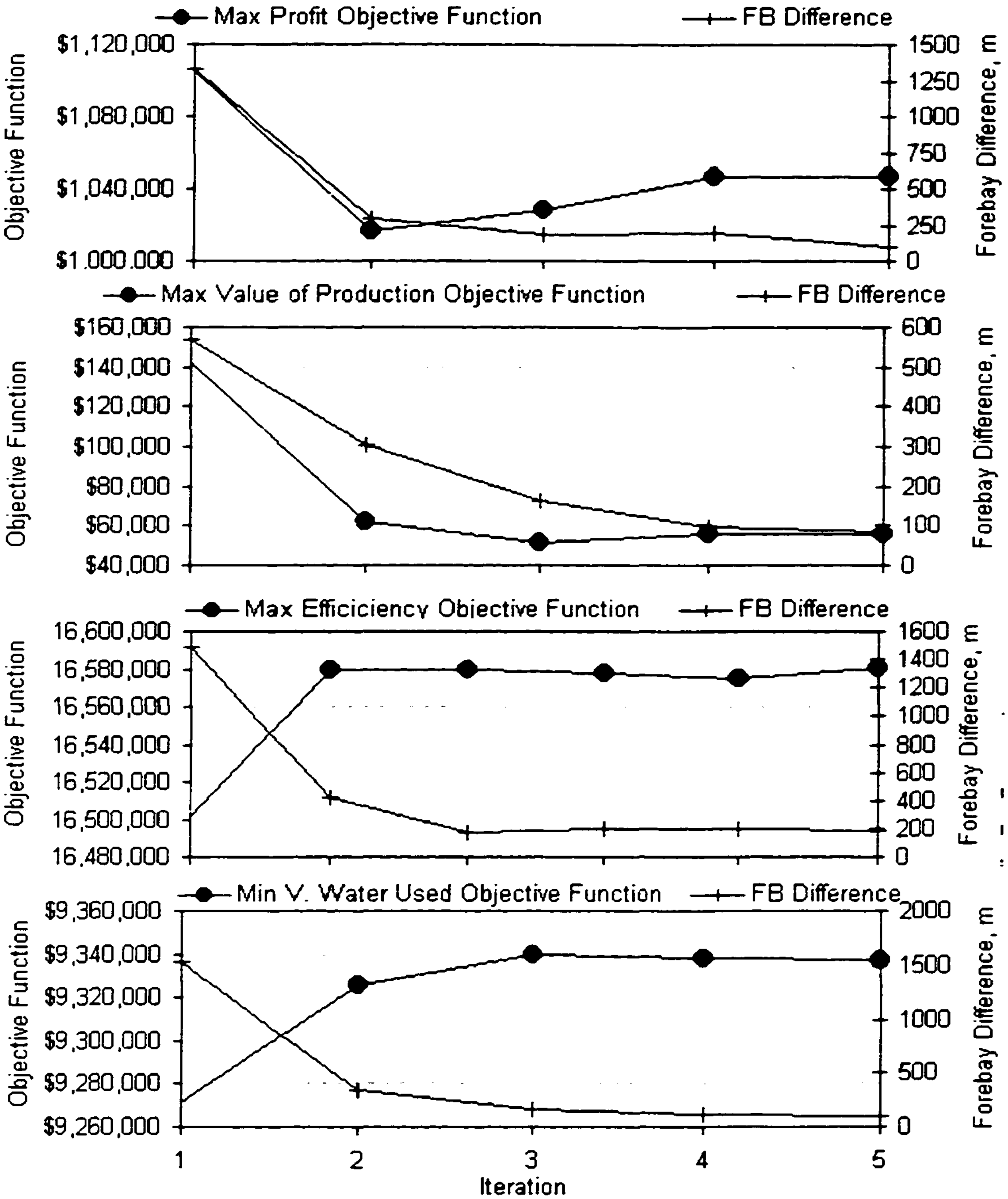


Figure 6.54. Convergenece of Forebay Levels and Objective Function Values for STOM Optimization Models.

iv. Behavior of Generation and Forebay Schedules in Iterations

The results of the generation and forebay schedules were saved from each optimization run to analyze their behavior -how they changed and converged from one iteration to the next. Figure 6.55 illustrates the variation of the generation and forebay schedules with iterations for the Peace Canyon. It can be seen that the general patterns of the generation and forebay schedules do not exhibit significant change from one iteration to the next. This indicates that the solution algorithm is stable and does not exhibit the wide fluctuations commonly found in optimization models of this type. The reason for this stability can be attributed to the use of piecewise linear generation production functions in STOM models. The use of the PWL function allowed the Simplex algorithms to load most plants at maximum efficiency. The slight changes in generation are due to the slight changes in the coefficients of the PWL function as the forebay levels changed. It should be noted that plants with small reservoirs (e.g., PCN) usually exhibited the largest fluctuations (e.g., Figure 6.55) due to the rapid change in their water levels from one hour to the next.

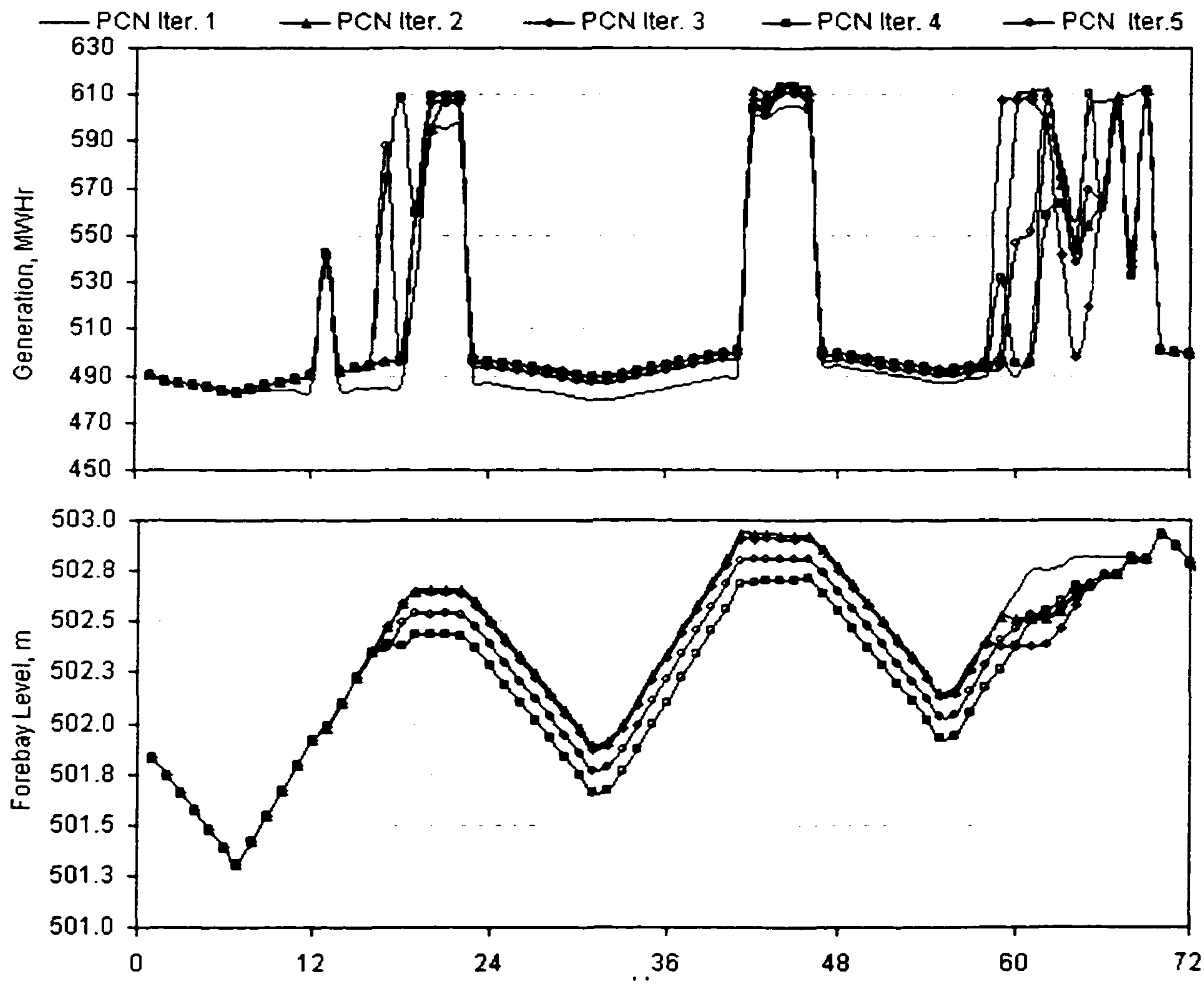


Figure 6.55. Convergence of Generation Schedules and Forebay Levels in Iterations.

6.3.2 *Performance of the Simplex Primal and Dual Algorithms*

Figure 6.56 compares the performance of the Simplex Primal and Dual algorithms for the Maximize the Profit objective function, for a study with 19 plants and 168 hours. It can be noted that the Simplex Dual algorithm outperformed the Simplex Primal algorithm in terms of the number of iterations (and CPU time) required to arrive at the optimal solution. The Dual formulation is believed to be more efficient than the Primal for solving a wide range of problems (ILOG, 1998). In particular, highly degenerate problems with little variability in the right-hand side coefficients, but with significant variability in the cost coefficients (typical for the problem at hand) usually solve much faster using the Dual algorithm. It can be noted, however, that the approach of the Primal algorithm to the optimal solution is more stable than the Dual algorithm, and for this reason it was decided to use the Primal algorithm for the initial optimization run in STOM models. Once the initial optimal solution is determined by the Primal algorithm, the Barrier and Dual algorithms are then used for subsequent runs. This, it was found, gives solution steps with improved stability and reliability for the hydroelectric scheduling problem at hand.

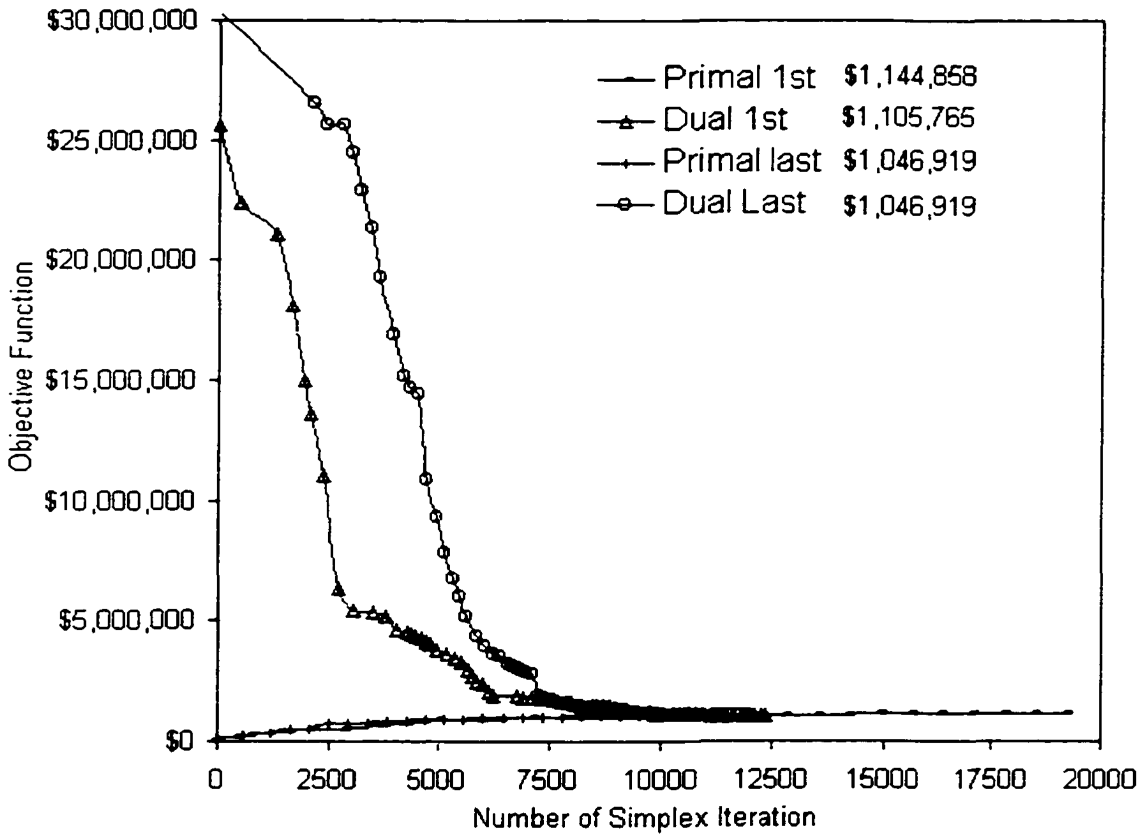


Figure 6.56. Performance of the Simplex Dual and Primal Algorithms.

CHAPTER 7
CONCLUSIONS AND RECOMMENDATIONS

7.1 SUMMARY

Background

This thesis describes the various aspects of developing and implementing a decision support system for managing a system of hydroelectric facilities for power supply operations. The experience gained over the last three years while working with one of the major reservoir management institutions in Canada and in North America is described. It is believed by the author that the application developed is "state-of-the-art" and compares favorably with similar applications elsewhere in the World. It is also believed that researchers have already developed a considerable body of knowledge which can be applied to reservoir operations planning, and that it is incumbent on water resources professionals to keep abreast with theoretical and technical developments in order to best serve the field and clients.

In this thesis, it is shown that there is now a wealth of knowledge in the field of Operations Research/Management Science, which can profitably be applied to optimization of complex hydroelectric facilities and reservoir operations. Over the last few decades the field of Operations Research/Management Science has developed numerous theories, techniques and decision support tools which can be used to achieve substantial improvements at various stages throughout the process of reservoir operations for hydropower generation. However although there are some notable exceptions, the majority of reservoir management authorities in North America and elsewhere in the World are not making full use of the opportunities to analyze and rationalize their reservoir operations. Many are using specific tools and optimization models to optimize long-term or individual facility operations. But too often the approach is piecemeal or fragmented leading to mismatched or sub-optimized links in the chain of the decision-making process and consequent lost opportunities and sub-optimal operation modes. The problems have intensified with the deregulation of electricity markets, where lost opportunities mean loss of substantial potential profits.

What was required was an approach to short-term hydroelectric system operations that integrates long-term policies, derived by higher level optimization models, and which seeks optimality across a complete system of reservoirs. Relieved of computational burden and armed with a powerful and flexible decision support system, which can be used to explore a range of alternative operational scenarios, the decision-maker now has far more time to perform the core activity of management, namely to think about alternatives and to proactively explore creative and efficient solutions to the problems which inevitably arise in complex hydroelectric system operations.

Operating Environment

In recent years, deregulation of the electricity production sector has had significant effects on the way generation production facilities are managed. Situated in-between two, rapidly growing, deregulated markets, and enjoying the full flexibility of hydroelectric production facilities, and facing the need to adapt to the new operating environment, B.C. Hydro was and still is looking for ways and methods to maximize the value of its resources from electricity trade transactions.

In operating a complex hydroelectric system in a competitive market the operational as well as the financial risks are high. Decision-makers and operators unarmed with rigorous analysis tools and techniques could cause their organization to pay dearly for their decisions. Traditionally the main objective of the system operator was to secure a stable supply of electric power to meet the local system load demand while meeting the system physical and operational constraints. The major driving force in making operating decisions was to ensure the availability of sufficient energy and capacity to meet the system demand while also meeting the non-power requirements and operational constraints. Theoretically speaking, in a competitive energy market industry there is always a price at which energy can be either sold or purchased. Prices then become the major driving force in making operational decisions. Under such circumstances, any physical or operational constraints limit the ability of the system operator to exploit the full flexibility of the system and to maximize the value of the resources. From this perspective the aim of the decision support system developed in this thesis was to assist the BC Hydro system operations engineers in improving the operational efficiency of the BC Hydro system and to make optimal or near optimal operational and trading decisions while meeting the constraints.

Objectives

This dissertation has presented various aspects of the development and implementation of the decision support system in production mode. The objectives of the decision support system are: to improve the efficiency of the generation system; to meet non-power requirements; to manage transmission constraints; and to incorporate real-time marketing information and medium term marginal values of water into the decision making process of preparing the generation, trading, and reservoir operation schedules.

Study Approach

The process of developing and implementing a successful decision support system for real-time hydropower scheduling in a competitive power market environment was based on a structured approach shown in Figure 7.1. The approach combined knowledge gained at each stage to set the direction and content for the following stages. The approach started with an analysis of the problem at hand. The analysis resulted in preliminary understanding of the decision problem and of the available methods and techniques that could beneficially be applied to solve the decision problem. It also set the stage for data collection and analysis, which have resulted in a deeper understanding of the main features of the problem and gave direction on innovative ideas to be tested and tried. Exploration of optimization methods followed, which included investigation of the state-of–the-art in industry and in academia, and of the most suitable and practical methods available to solve the hydroelectric scheduling problem at hand. Implementation of the optimization model in production mode required development of other components of the system to make the optimization model easy to use in real-time operations. Finally, communication and interpretation of the optimization results gave the opportunity to users to gain deeper understanding of the optimal behavior of the hydroelectric system under different market and operating regimes.

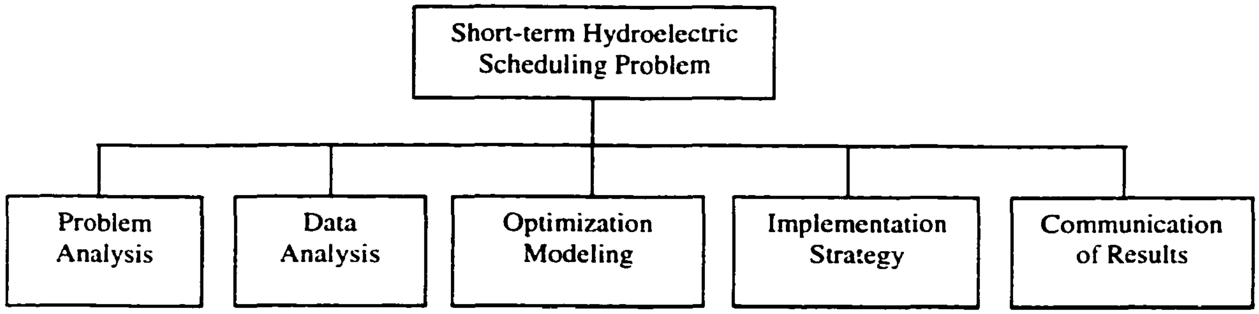


Figure 7.1. A Structured Approach to the Short-term Hydroelectric Scheduling Problem in a Competitive Market Environment.

Design Philosophy and Components of the System

This thesis has presented a decision support system that emphasized the view that higher level decision-making will, now and in the near future, be made by human decision makers. The intent of the system is to aid the decision-maker in making informed decisions. The thesis has argued that there is a slow convergence between analytical techniques, information technology, and the needs of organizations in charge of management of real-life, large-scale, complex systems. It is believed that this convergence will eventually change the way decision-making is currently done in organizations. The decision support system developed by this thesis, to aid BC Hydro system operations engineers in decision-making situation, is a proof of the practical applicability of optimization models and of such decision support systems in real-life situations.

The system consists of six components: the input data preparation routines, the Graphical User Interface (GUI), the communication protocols, the hydraulic simulation model, the Optimization model, and the results display software.

Modeling Methodology

The design and formulation of optimization models and the modeling methodology adopted by this thesis have met the operational as well as the technical requirements of the decision support system as outlined by the users requirements. The features of the piecewise linear functions were found to be very powerful when used in combination with linear programming algorithms to determine the optimal allocation among production facilities.

The optimization models, and in particular the Maximize Profit optimization model, have behaved in an acceptable and reliable way and have met and exceeded user's expectations. In arriving at the generation and trading schedules, the optimization models factor-in all user-specified information on the modeled systems and on market conditions, and it produces reliable and believable generation, trading, and reservoir schedules that can aid the system operations engineers in arriving at decisions on when and how much to import and/or export and how much thermal energy to generate as well as when, where and how much water to store in or draft from each reservoir while meeting the domestic load and other system and market constraints.

Implementation Process and Strategy

The research work presented in this thesis is particularly concerned with the practical applicability and implementation of the proposed method to large-scale hydroelectric generating systems. Unlike the previous literature which dealt mainly with purely thermal, or a mix of hydrothermal systems, this work considers predominantly hydroelectric generating systems, with a very small component of a thermal system. The research also highlights the implementation process adopted and points out important factors that need to be taken into consideration in order to successfully develop and implement operations research methods for short-term scheduling of hydroelectric facilities in real life situations. These factors address the main obstacles that have, so far, prevented the widespread use of optimization techniques to the problem of real-time and short-term scheduling of hydroelectric facilities.

Benefits

The benefits of developing and implementing the decision support system are considerable, and they can be summarized as follows:

- First, the decision support system developed by this thesis is a living proof that operations research methods can provide significant improvements over heuristic and manual methods for complex real-time system operation. Developing such systems, however, requires patience, persistence, lots of common sense and good judgement.
- Second, the postmortem testing phase showed that the gains from using the system accounted for about 0.25% to 1.0% in stored potential energy. Analyses of results presented in this thesis have indicated that the expected monetary gain in stored energy could amount up to CAN$11.4 million per annum. Even a very conservative estimate yields a monetary gain of about CAN$4.48 million per annum. Thus, the financial returns from using the decision support system greatly outweigh the costs of building it.
- Third, compilation and verification of STOM's physical input data have resulted in the creation of a very accurate database on the majority of hydroelectric facilities managed by BC Hydro. In addition, STOM's operational data requirements provided significant benefits in verification, and in many instances in finding sources of error in operational data.
- Fourth, the exercise of building STOM led to the explicit recognition of relationships that were not realized before. For example, the utilization of the concept of optimal unit commitment and its use to derive the plant's piecewise linear generation production functions has resulted in the introduction and use of the methodology and the exploitation of its features in the solution algorithm.
- Fifth, STOM acts as a unifying instrument for organizational functions. The obvious example in STOM is the function of BC Hydro's Power Supply and the Marketing Business Units, where divergence of objectives could exist. Production could well be trying to satisfy certain requirements (e.g., meeting the domestic load, meeting reliability criteria or environmental limits, etc). Marketing may be trying to maximize the total volume of sales rather than concentrating on maximizing profits, or value of resources. From this perspective, STOM acts as an instrument to unify the objective of the organization, namely, to maximize the value of resources.

- Sixth, the bulk of work in this research project was carried out by the author with some programming and data collection help from other graduate and undergraduate students at UBC and at BC Hydro. The benefits of using students are several folds. The cost of technical expertise to BC Hydro was low (in comparison with consultant fees), while the gains to BC community and the country are significant (mainly from training students on real-life problem solving techniques, and from developing the knowledge-base and technical expertise for hydropower system operations locally). Also the university environment ecourages a degree of abstraction that greatly helped conceptulization and formulation of the approach. B.C. Hydro people are very practical and abstraction does not come to them naturally.
- Seventh, STOM considerably shortened the time needed to prepare the generation and trading schedules, and the system operations engineers now can beneficially use the time saved to focus on more important aspects of their job.
- Finally, STOM provides the important, and required, link in the decision-making process between the long/medium-term planning and coordination studies and real-time system and marketing operations. The main drivers of STOM are market prices and the value of resources, which are to a large extent, the main driving forces in electricity markets today.

Lesson Learned

The main lesson learned from developing and implementing the decision support system was that there is no alternative to workng very closely with the intended end-users of the system, and with the people who have deep knowledge, experience and understanding of how the system is and should be operated.

7.2 CONTRIBUTIONS

The major contribution of this work was the development and implementation of a practical and detailed large-scale optimization model that determines the optimal tradeoff between the long-term value of water and the returns from spot trading transactions in real-time operations. Until now short-term optimization models have rarely been used by the people who actually manage complex power systems in real-time. There are several reasons. First, most models were not easy to use as the computer technology needed to model complex power systems were not capable of meeting the needs of the end-user in terms of ease of use and the time it takes to run them. Second, most of the models were developed for specific studies (mostly academic) and did not reflect enough of the complexity and flexibility that was required by the end user. Third, the people who can and do apply optimization techniques are generally working at an "academic", abstract level that operators, accustomed to taking direct responsibility (and risk) for their day to day operations have difficulty relating to. Fourth, operators do not always understand the esoteric theory and often do not accept the simplifications necessary to match the available techniques to the situation at hand. Fifth, it simply takes considerable amount of time, patience, and effort to develop, calibrate and to implement such complex models in real life situations.

Despite the difficulties, STOM was developed, calibrated, and implemented through a team effort of the BC Hydro's staff, and researchers from the University of British Columbia. Several factors have contributed to the success of the development and implementation of

STOM. First, all levels of BC Hydro's management have provided considerable support for the development and implementation of STOM. Second, STOM users have viewed it as a decision support tool to aid them in making their decisions, and not as a system that will someday replace them. Third, the development and implementation strategy of STOM was carried out incrementally. Fourth, several staff and the shift engineers were directly involved in setting out the functional requirements and modeling details that have accurately captured the physical as well as the operational characteristics of the generating system. The operators are currently experimenting with the system in production mode, and are gradually gaining confidence that the advice provided is accurate, reliable and sensible.

Other contributions consist of the ability of the decision support system to produce generation, trading and reservoir schedules that are technically and operationally feasible from the point view of the system operator. This feature is not accidental, as it required deep understanding of the behavior and properties of the generation production function. This understanding gave rise to the innovative procedure to curve fit the piecewise linear function in order to exploit properties of the solution algorithm in linear programming.

Implementation of the research project in close proximity and collaboration with the end-users of the research outcome has resulted in deeper understanding of the needs of the organization. However, an unexpected outcome of the research project was the unforeseen sudden growth in interest in applying optimization techniques in an organization such as B.C. Hydro. Successful implementation of the decision support system developed by this thesis at B.C. Hydro has resulted in the belief that optimization models could significantly improve the way hydroelectric systems are operated. This, it is believed, is a major contribution.

7.3. FUTURE RESEARCH REQUIREMENTS

Future research is needed to address issues related to the subject matter of this thesis and to extend and enhance the decision support system and the modeling methodology adopted in this research. The research areas could be classified under three headings: Overall Approach for Hydroelectric System Operation Planning; Extensions of the Decision Support System, Extensions of the Modeling Methodology.

7.3.1 Future Research on Overall Approach for Hydroelectric System Operation

Future research in this area will benefit the practice of system operations, and will enrich our understanding of the decision-making processes in organizations dealing with hydroelectric systems. Organizations managing such complex systems are in urgent need for decision support tools to aid them in making rational and conceptually correct decisions. On the other hand, academics are full of ideas on advanced decision-making techniques. There is, however, a missing link in-between the two, and future research is needed to bridge the gap between academia and industry.

Research on development of an overall approach for system operations planning for hydroelectric facilities under the new market structure is needed. Future research to design the overall framework and to investigate the nature and context of the decision making process employed by organizations, such as BC Hydro, is needed. Once the decision making process is outlined, the most suitable operational models (including existing models) would be identified. The overall approach will most likely outline the information needed to pass from one level of modeling to the next, all the way to real-time operations. This research effort could be carried out in close coordination with real-life system operations staff at BC Hydro, and it is believed that it could produce pioneering research work in this important research area.

7.3.2 Future Research on Possible Extensions of STOM

At present, two extensions to the solution algorithm have been preliminarily investigated. The first concerns what can be termed the concept of implied marginal value of water (or energy), given market conditions, hydroelectric system status, and planned schedules. The second concerns what has been termed the concept of proximal decision analysis (Howard, 1971), to find the optimal price of hydropower production from the perspective of a hydropower producer in electricity markets. The two concepts warrant further research, and consideration of their use has been discussed in a preliminary way with system operations engineers at B.C. Hydro.

i. The Concept of Implied Marginal Value of Water (or Energy)

The concept of implied marginal value of water (or energy) stems from the need of the decision-maker to determine how close the dispatched schedules are to the optimal, given market conditions and system constraints. The concept seeks to assess how the market (or the system operator) values the system resources in a given time frame. When used in postmortem studies mode, the analysis could indicate to the system operator (or higher level management) how the market valued the producer's resources. Alternatively, when used in real-time operations mode, it could provide the system operator with valuable information on the variation of the optimal system production function with the assumed value of resources - given prevailing market conditions and system constraints. This concept could help the decision-maker to investigate two questions:

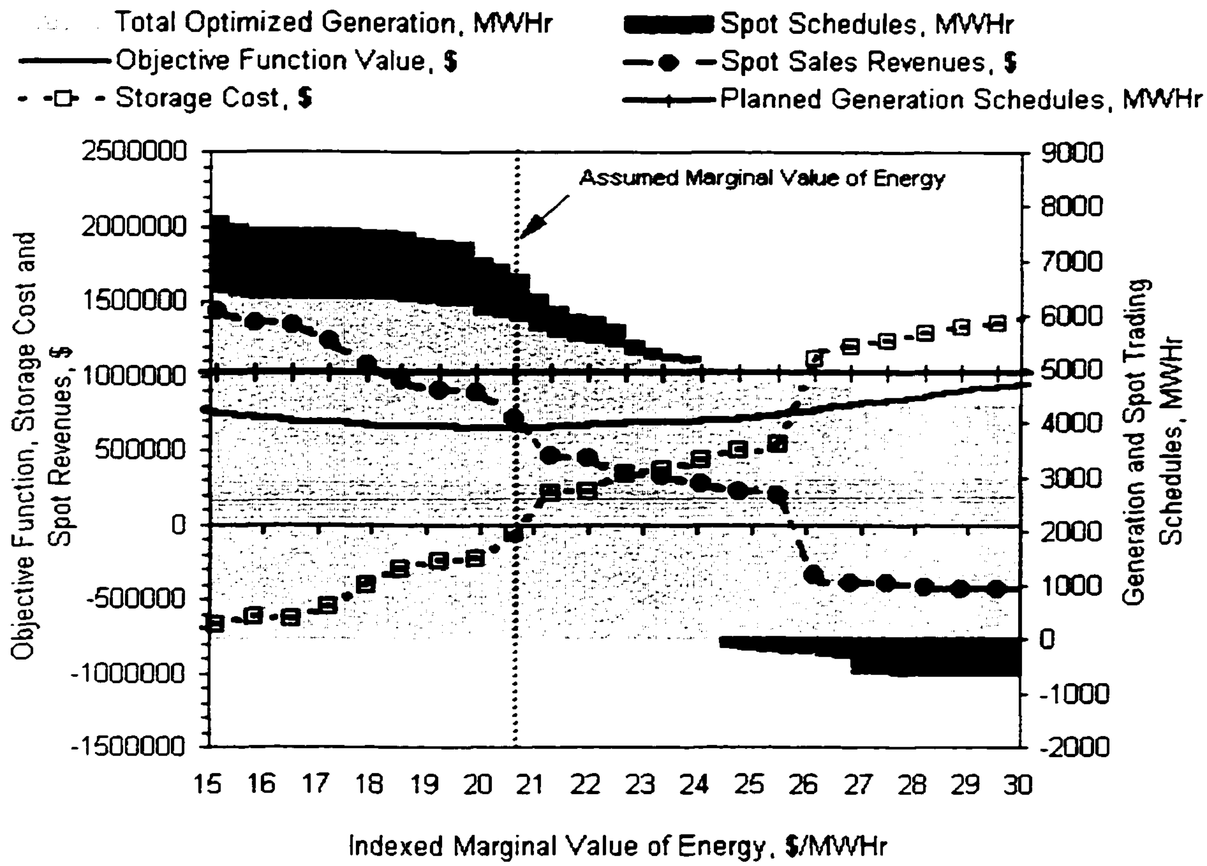
- how far the dispatched schedule is from optimal?
- what is the implied marginal value of dispatched energy?

Answers to these questions could help the system operator to better understand the behavior of the system under different operating regimes and market conditions. This type of analysis could warrant the use of some features of parametric programming in the CPLEX solver. Further research and development on such topics are needed to exploit the full potential of the decision support system developed in this thesis.

ii. The concept of Proximal Decision Analysis for a Hydropower Producer.

Proximal decision analysis (Howard, 1971) stems form the uncertainty inherent in specifying some of the coefficients and input data in the optimization model and from the need to overcome some of the drawbacks associated with the most important of these assumptions. For instance, determination of the marginal value of energy by means of stochastic dynamic programming techniques entails several assumptions on flows, market conditions, and on modeling details.

Results from the implied marginal value of energy analysis could also be used to determine the optimal value of resources from the point of view of a hydropower producer. Preliminary results have indicated that the objective function could be approximated by a differentiable convex function. Figure 7.2 illustrates results of running STOM for different values of the marginal value of energy (Rbch). It can be noted that the objective function is convex, while the the value of spot sales and storage cost resembles the market's supply and demand function. For a hydropower producer the properties of this objective function and the way the properties change, given uncertainty in input data, could be investigated, perhaps to detemine the optimal value of Rbch, given market and system constraints. For instance, the bottom chart in Figure 7.2 illustrates what could be termed as the producer's market demand function, which simply illustrates the effect of varying Rbch on the optimal trading schedules, and the market value for spot trading schedules from the point of view of the producer. The same analysis could be carried out to investigate the effect of other input parameters in the model using parametric programming techniques (e.g., spot market price, tie limits, inflows, etc), and further research is needed to flesh out the significance of such relationships.



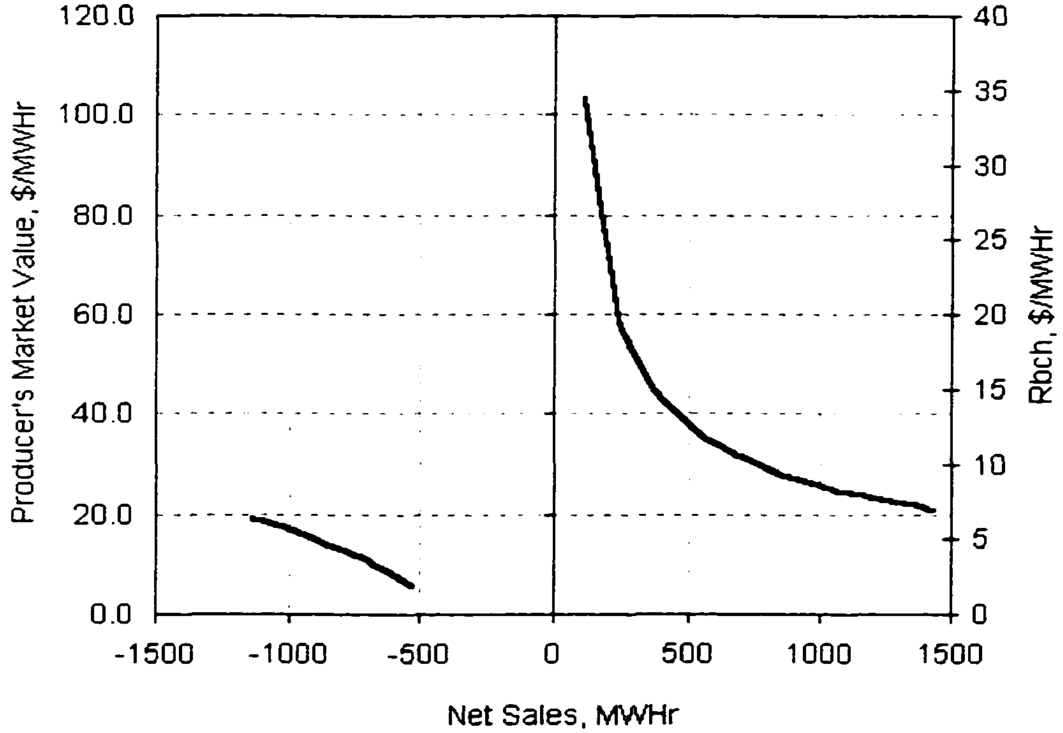


Figure 7.2. The Concept of Proximal Decision Analysis, and Producer's Market Value Function.

7.3.3 *Future Research on Modeling of Hydroelectric Systems*

Future research is needed to extend the current modeling methodology adopted in this thesis. The following areas of research could serve as a road map for future extensions of the decision support system developed in this thesis:

- Research on the potential use of advanced decision support tools, such as expert systems is needed. Expert systems could be used in many areas of hydroelectric system operations and they could include:
    - Assessing the meaning of sensitivity analysis data to system and market operations.
    - Interpretation of results of optimization models,
    - Assessing and formulating constraints for optimization models.
    - Interpretation of infeasibility causes in optimization studies and recommending solutions to the problem.
- Research on ways and methods to include simplified, yet, representative uncertainty in the decision support system is needed in many areas:
    - Uncertainty in load,
    - Uncertainty in tie line limits and in spot market prices,
    - Uncertainty in the marginal value of resources, and
    - Uncertainty in inflows.
- Research on automation of scenario analysis, in production mode, is needed. The research should focus on ways and methods for scenario generation and modeling.
- Further research is needed to investigate available modeling methodologies to include the effect of head variation in the optimization model. Head variations include the effect of tailwater fluctuations and reservoir drawdown. It is believed that inclusion of head variations in the optimization model will significantly reduce the number of iterations required for convergence of the current solution algorithm and will improve modeling methodology of hydroelectric systems.
- Future research is needed to generalize the curve fitting procedure for the piecewise linear generation production function. The research could focus on linking the number of segments in the piecewise linear functions to the number of generating units it represents. This will give more realistic hydroelectric generation and reservoir schedules.
- Research on the behavior of marginal value of water for small reservoirs, and other sensitivity analysis information derived by the model is needed. The research could focus on methods for deriving the marginal value of water from sensitivity analysis data, and on their potential use to better reflect current operating conditions for small reservoirs.
- Research on forecasting spot market prices is urgently needed. Ideally, the research effort would focus on deriving the market demand function. Once available, this function could easily be built into the Maximize the Profit optimization model to give more accurate representation of market(s) structure.
- Further research and development of the decision support system developed by this thesis is needed to generalize the model for use by others at B.C. Hydro, and potentially by others in the industry. The optimization model, and other components of the decision support system, could potentially be marketed to other hydroelectric power producers. This, however, would require further research and development effort to make the system adaptable to any hydroelectric system with any possible configuration.

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ANNEXES

ANNEX A
SIMULATOR PROGRAM GENERAL ALGORITHM

ANNEX A
Simulator Program General Algorithm

(Source: Ristock et al., 1998)

Begin Program

A. Initialization

1. Initialize all variables.
2. Read input data:
   - Read operational input data
   - Read Physical input data
   - Read User defined input data generated by the Graphical User Interface
   - User Optimizer Input Data
3. Calculate initial storage based on initial forebay.

B. Main Program Loop

1. Check that starting elevations are within operational limits:
   - print warning if starting forebay is not within limits
2. For Hour = Starthour to Endhour Do

   For each Plant in CONTROL file Do

   a. Calculate Forebay at end of hour:
      - Convert scheduled G to Q:
        - i. If plant has linearized SPUC equations:
          - Calculate G and Q breakpoints
          - Convert G to Q using breakpoints
        - ii. If plant has HK values:
          - Calculate HK value
          - Convert G to Q using HK value
      - Calculate all appropriate discharges: scheduled spills, weir spills, gate releases, statutory releases, and special releases
      - Calculate Total Inflow
      - Calculate Total Outflow
      - Calculate new Storage via mass-balance equation, and use storage tables to convert to new forebay

   b. Store G and Q breakpoints for the Optimizer

   c. Check that the calculated forebay is within operational limits:
      - print warning if not.

   d. Perform Tailwater calculations:
      - not available - to be added in future

   e. Calculate Max & Min G and Q limits:
      - i. Calculate Minimum Allowable G and Q limits

- calculate the Minimum physical plant G for current hour (algorithm to be changed in future)
- calculate Allowable Minimum plant G as greater of Min physical G and user-imposed Gminimum
- calculate Minimum turbine Q associated with this Allowable minimum G. Then Min plant Q = Min turbine Q + non-turbine releases
- calculate Allowable Minimum plant Q as greater of Min plant Q and user-imposed plant Qminimum. Hence Allowable Min turbine Q = Allowable Min plant Q - non-turbine releases
- if necessary, recalculate Allowable Min G based on this new Allowable Min turbine Q
- if scheduled G falls below Allowable Min G, then print warning

ii. Calculate Maximum Allowable G and Q limits

- calculate the Maximum physical plant G for current hour
- calculate Allowable Maximum plant G as lessor of Max physical G and user-imposed Gmaximum
- calculate Maximum turbine Q associated with this Allowable Maximum G. Then Max plant Q = Max turbine Q + non-turbine releases
- calculate Allowable Maximum plant Q as lessor of Max plant Q and user-imposed plant Qmaximum. Hence Allowable Max turbine Q = Allowable Max plant Q - non-turbine releases
- if necessary, recalculate Allowable Max G based on this new Allowable Max turbine Q
- if scheduled G exceeds Allowable Max G, then print warning

C. **Format and Write Results for Optimizer & Display**

1. Read, format and write files for the Optimizer
2. Write all calculation results required by the Optimizer or for display purposes to the simulation output file.

End Program.

ANNEX B
TO DO CHECKLIST TO RUN THE SHORT TERM OPTIMIZATION MODEL (STOM)

ANNEX B
To Do Checklist to Run the Short Term Optimization Model (STOM)

1. On the NT PC, PSO 1st Shift Office, Edmonds, or on Workstation No. 6 PSOSE Shift Office, Park Place, or on any client workstation equipped to run the Short Term Optmization Model, open Excel 97.
2. Open both the latest version of the LRB (Ver. LRB5.1 or later) and the FBFC (ver. 3.8 or later).
3. To run postmortem analysis, select the first day of the analysis (e.g., yesterday) as Day 1 in the LRB and FBFC. To change dates in the LRB use the "DAY1 DATE" button, and in the FBFC use the "Change Current Date" in the "Forebay" menu.
4. Link all plants for 96 hours from the "Forebay" dropdown menu.
5. Use the "Load Data" button in the LRB Toolbar to check if PSOSE did save the LRB schedule data just before the rollover for the desired study dates. If data is saved, then retrieve the schedule(s), else, go to step 8.
6. Use the "Load Data from file" in the FBFC's "Forebay" drop down menu to check if PSOSE did save FBFC data before the rollover for the desired study dates. If data is saved, then retrieve it, else, go to step 9.
7. If PSOSE did not save the LRB data for the desired study date(s), then:
   - Use "UpdateGen" button in the LRB to retrieve generation data from PI.
   - Use "Load" button in the LRB to retrieve the historical load form PI.
   - Guess the WKP load ratio (e.g., 0.09 or 0.10)
   - Update Generation limits in Cap1 and Cap2 for the study date(s)[1].
8. If PSOSE did not save the FBFC data for the desired study date(s), then:
   - Use the "Retrieve Gen and Forebay Data from Hour 1 to current hour" in the "Forebay" menu to update the FBFC data.
   - Use the "Retrieve FLOCAST/FLOCAL values" in the "Forebay" menu to update the inflows and spills.
   - Use the "Accept All FLOCAL/FLOCAST values" item in the "Forebay" menu to copy the inflows and spills to their appropriate ranges.
   - Use the "Retrieve Operating Levels" item in the "Forebay" menu to update the forebay operational limits.
9. Check LRB and FBFC data for errors or drop out values:

LRB		FBFC	
Check Generation Data		Check Generation data match LRB	
Check BCH Load data		Check Forebay levels	
Check WKP Load data		Check Inflows	
Check Export and Import Schedule		Check Spills	
Check Spot Exports and Imports		Check PI data (No Div/0!)	
Check Generation Capacities		Check FB's within limits	

10. Balance Spots in the LRB for planned schedules.
11. Adjust inflows, spills to match actual and calculated FB's. If inflows or spills are unrealistic, use Goal Seek in Excel Tools menu to adjust the HK[2] values as the last resort.
12. Generate the outage.dat file by running the unit outage software ORF.

[1] See Annex C for the procedure to prepare the unit's outage schedule and the outage.dat file.
[2] Adjustments to the HK values should be used as the last resort to balance the FBFC levels. See section 3.1.1. Step 8 for more details.

ANNEX C

THE SHORT TERM OPTIMIZATION MODEL SOFTWARE PROGRAMS

ANNEX C

THE SHORT TERM OPTIMIZATION MODEL SOFTWARE PROGRAMS

The following software routines and packages have been developed and used in STOM. The clients side software assist the shift engineer running STOM and to automate the overall process, while the Server side runs the simulation and optimization models.

Name	Function	Workstation
SaveToTextAllDat	Input data checking, saving, formatting and launch the GUI. Code contained in the "MsimOptOutput" Visual Basic/Excel module in the LRB.	Client
OptMain.exe	Graphical User Interface (GUI) Select the plants to be simulated/ optimized, and set parameters of the simulation and optimization study	Client
Optresults.exe,	Launch an Excel session and open "moretest.xls", and launch the Optimization Results dialogue box.	Client
Moretest.xls	Ouput data presentation programs. Format and display the simulation/ optimization results for the user	Client
c.exe	Client side communication protocol	Client
s.exe	Server side communication protocol	Server
PKZip.exe™	Data compression and decompression software	Client, Server
PKUnzip.exe™	Data decompression software	Client, Server
Sim.exe	Hydraulic operation simulator model	Server
Optimization Model files	Optimizer model	Server
CPLEX.exe™,	Linear Programming Solver Package	Server
AMPL.exe™	General purpose algebraic modeling language	Serve

ANNEX D
FUNCTIONAL FEATURES OF THE GRAPHICAL USER INTERFACE

Annex D

Functional Features of the Graphical User Interface

This Annex details the main features of the Graphical User Interface (GUI).

D.1. Selecting River Systems and Plants for the Study

The GUI, shown in Figure D.1, includes the 12 major river systems and 34 hydroelectric plants or facilities operated by B.C. Hydro. A river system could contain one or more of its tributaries (e.g., the Columbia River), and each river system could contain one or more hydroelectric generating plants or facilities. Currently, the GUI allows the user to select up to 9 river systems and 19 plants to be included in the simulation/optimization study, as listed in Table D.1. Some river systems, or plants, have been deactivated due to the lack of a complete set of operational input data, or, because they require special simulation algorithms (e.g. Jordan, Kootneay, Coquitlam, Puntledge river systems, and the Arrow reservoir, WGS, and WHN plants). A dark-gray plant name indicates the plants that cannot be simulated and optimized (e.g. ARD, WGS, WHN in the illustration above). Once a complete set of input data is available, and the simulation algorithms have been finalized, the user can simply change a configuration text file to reactivate these plants, and allow the user to select them for either simulation/optimization study.

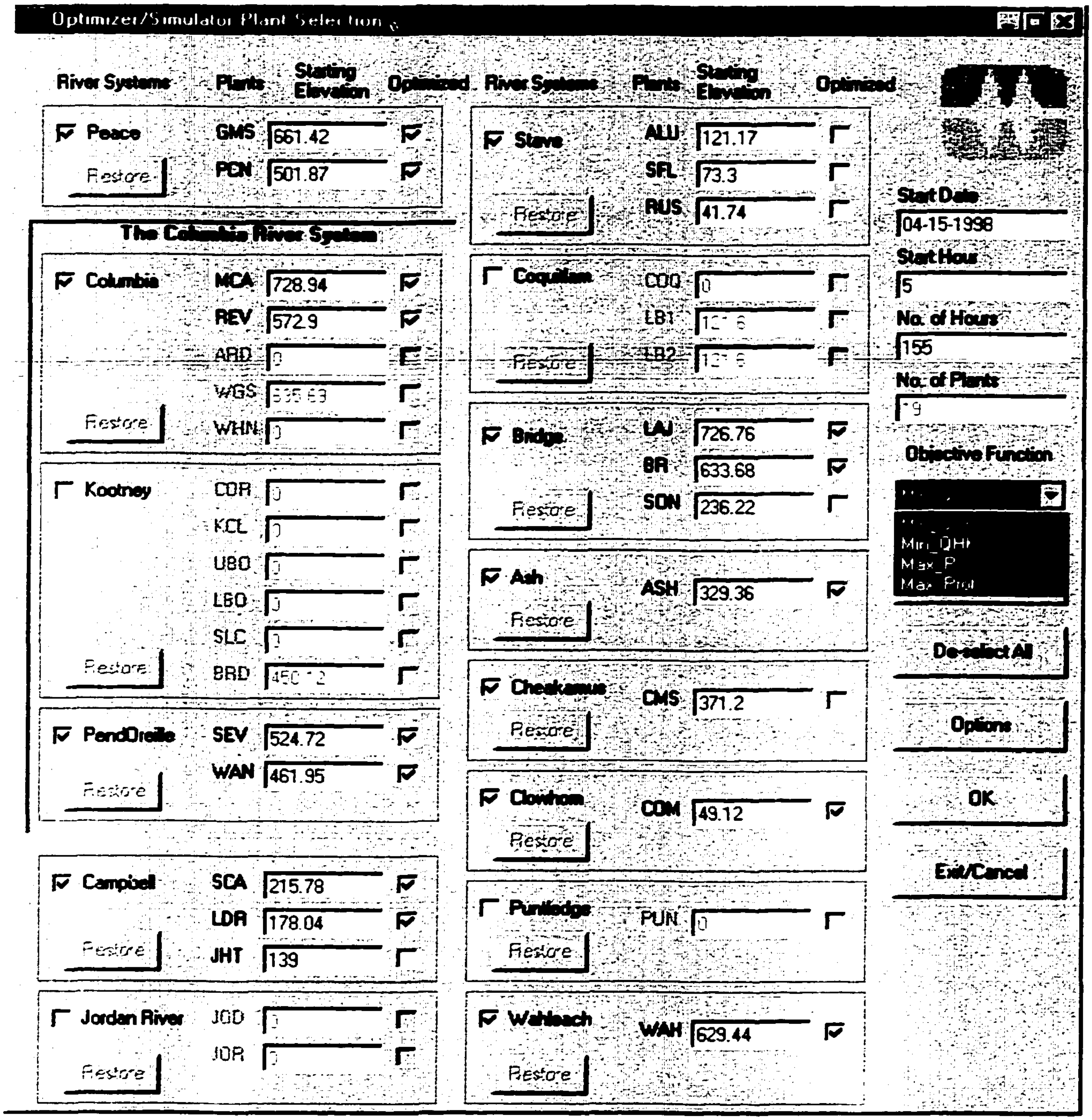


Figure D.1. STOM Graphical User Interface

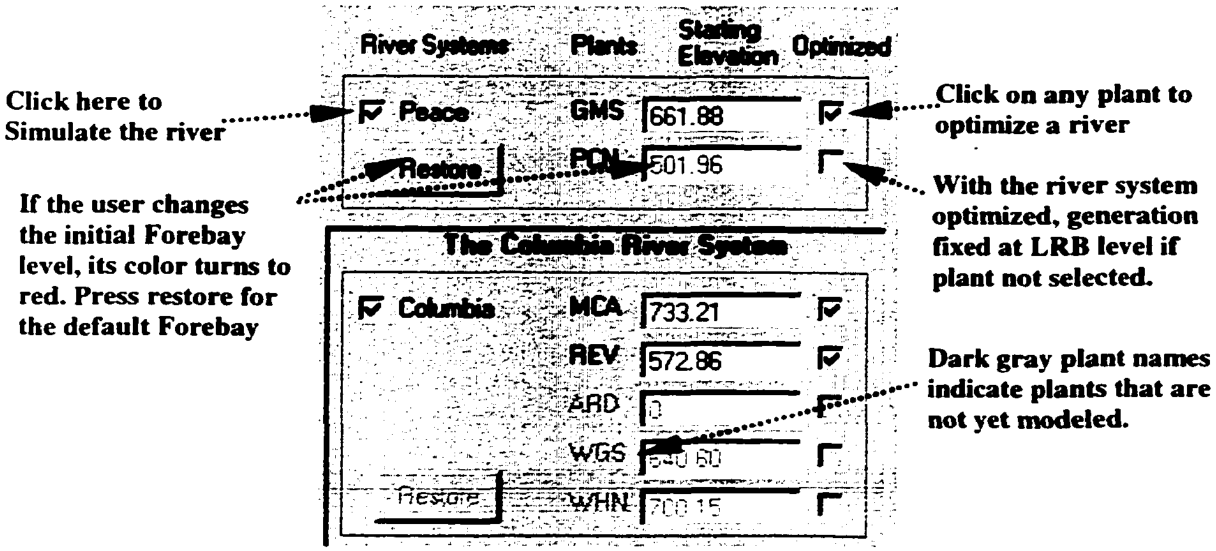


Figure D.2. Selecting a River Systems and Plants

As shown in Figure D.2, If the check box next to a river system name is clicked, the river system will be simulated. To optimize the river system, the user must check at least one plant under the "Optimized" heading. When a river system is selected, then all the plants in that river system will be simulated. If, at least one plant in a river system has been selected for optimization (e.g. the Peace system), then the entire set of plants in the river system is optimized. The generation schedule of plants that are not selected for optimization in an optimized river system is fixed at the LRB scheduled generation. To inform the optimization model on this user's choice, an instruction is automatically generated and saved to a text file when the GUI session ends. This instruction has been formatted in such a way that it can be included in the optimization model, and it consists of the following AMPL modeling language syntax: "`fix {t in initial..T} P['PCN', t]`;". Where "`fix`" is an AMPL command that fixes the variable "`P`" in the optimization model for the "`PCN`" plant for time steps "`t`" starting at the "`initial`" time step and up to the last time step in the study "`T`". If more than one plant, in an optimized river system were selected for optimization, the same instruction is repeated with the corresponding identification for the plant. Being able to issue instructions of this type is one of main advantages of using a general purpose modeling language such as AMPL. Once the GUI session ends, the file containing the instructions is transferred by the client side communication protocol to the NT Server and is later included in the optimization model to fix the LRB generation schedule (the Peace Canyon in this case). As a general rule, this option can be used for plants downstream of other plants in a river system. In addition to fixing its LRB generation schedule, the generation and turbine discharge limits for the concerned plant are dropped by the following AMPL instructions:

- `drop {t in initial..T} PLANT_DISCHARGE_BOUNDS['PCN',t];`
- `drop {t in initial..T} TURBINE_BOUNDS['PCN',t];`
- `drop {t in initial..T} GENERATION_LIMITS['PCN',t];`

It should be noted, however, that the forebay level limits of the plant are not dropped from the optimization model. The rationale for this methodology is primarily to maintain the plant's forebay elevations (PCN in this case) within their operational limits by optimizing the generation schedule of the upstream plant (GMS in this case), otherwise, turbine discharges from the upstream plant could cause downstream forebay levels to exceed their limits. This is particularly the case since most downstream reservoirs are small, and are located below large capacity plants (e.g., PCN is located downstream of GMS).

Table D.1. River Systems and Hydroelectric Facilities in the GUI

River System	Currently Modeled	Hydroelectric Generating Plants (ID)
The Peace River System	✓	Gordon M. Shrum Generating Plant (GMS)
	✓	Peace Canyon Generating Plant (PCN)
The Columbia River System		
• *The Upper Columbia River System*	✓	Mica Generating Plant (MCA)
	✓	Revelstoke Generating Plant (REV)
	✗	Arrow Lakes storage facilities (ARD)
	✗	Whatshan Generating Plant (WGS)
	✗	Walter Hardman Generating Plant (WHN)
	✗	
• *The Kootenay River System*	✗	Corra Linn Generating Plant (COR)
	✗	Kootenay Canal Generating Plant (KCL)
	✗	Upper Bonnington Generating Plant (UBO)
	✗	Lower Bonnington Generating Plant (LBO)
	✗	South Slocan Generating Plant (SLC)
	✗	Brilliant Generating Plant (BRD)
	✗	
• *The Pend d'Oreille River System*	✓	Seven Mile Generating Plant (SEV)
	✓	Waneta Generating Plant (WAN)
The Campbell River System	✓	Strathcona Generating Plant (SCA)
	✓	Ladore Generating Plant (LDR)
	✓	John Hart Generating Plant (JHT)
The Jordan River System	✗	Jordan Diversion Weir (JOD)
	✗	Jordan Generating Plant (JOR)
The Stave Falls River System	✓	Allouette Generating Plant (ALU)
	✓	Stave Falls Generating Plant (SFL)
	✓	Ruskin Generating Plant (RUS)
The Coquitlam River System	✗	Coquitlam Lake (COQ)
	✗	Lake Buntzen Generating Plant 1 (LB1)
	✗	Lake Buntzen Generating Plant 2 (LB2)
The Bridge River System	✓	Bridge Generating Plants (BR)
	✓	La Joie Generating Plant (LAJ)
	✓	Seton Generating Plant (SON)
The Ash River System	✓	Ash Generating Plant (ASH)
The Cheakamus River System	✓	Cheakamus Generating Plant (CMS)
The Clowhom River System	✓	Clowhom Generating Plant (COM)
The Puntledge River System	✗	Puntledge Generating Plant (PUN)
The Wahleach River System	✓	Wahleach Generating Plant (WAH)

D.2. Confirming the Starting Forebay Elevation

The starting elevation input data field shown in Figure D.2 above, has been provided for the user to confirm the initial forebay elevation for the simulation and optimization run. The default forebay values listed in the GUI are read from the actual forebay elevations in the LRB system, as saved in the LRB input data files. If the user modifies the starting elevation for a plant, then the color of the starting elevation will change to red (e.g. PCN in the illustration above), and the restore button will be activated. The user can restore the original value of the starting elevation by pressing the restore button. The starting elevation is an important input parameter in the study and this facility was provided to check the elevation for any obvious errors or bad input values that might have slipped by during the data check procedure outlined in Section 4.3.1.

D.3. Setting the Time Parameters for the Study

As shown in Figure D.3, the user can set the study start date, start hour, and the number of hours in the study by simply entering the values in the appropriate input data field shown below:

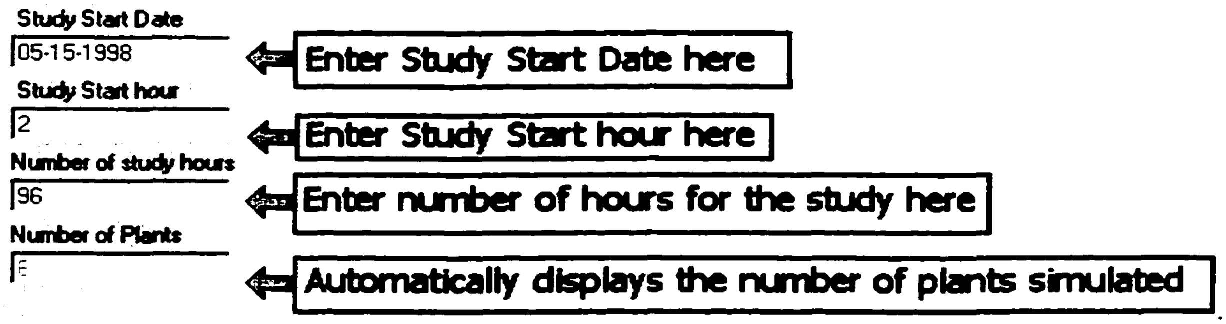


Figure D.3. Setting Study Start Date and Duration

The Start Date and the Study Start Hour correspond to the first day and hour in the LRB system.

The format of the start date depends on the default setting of the computer used (e.g. *dd-mm-yyyy*). The start hour sets the first hour in the study. The range of values for the start hour varies from 1 to 168. If the user changes the start hour, the starting forebay elevations for all plants will change automatically to display the forebay elevation for the previous hour (Study Start Hour – 1). The number of hours for the study determines how many hours, from the start hour, the study will run. The range of values for the number of hours for the study varies from 1 to 168, depending on the start hour. The last time step in the study will, in no case exceed 168, and the GUI will automatically set the maximum allowable value if it has been exceeded. The number of plants displays the total number of plants selected for simulation.

D.4. Setting the Operational Limits and Discharges

The "Options" button provides the user with the capability to set the following operational limits, for each plant:

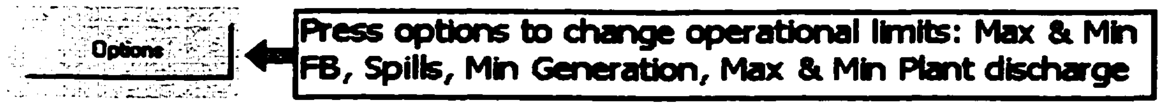


Figure D.4. The GUI Options Button

- Hourly plant forebay operational limits;
- Hourly plant discharge operational limits;
- Hourly scheduled spills; and
- Hourly values for minimum generation limits.

To set the above operational limits and parameters for a plant, the user can press on the drop-down bar as shown in Figure D.5, scroll down, and select a plant ID.

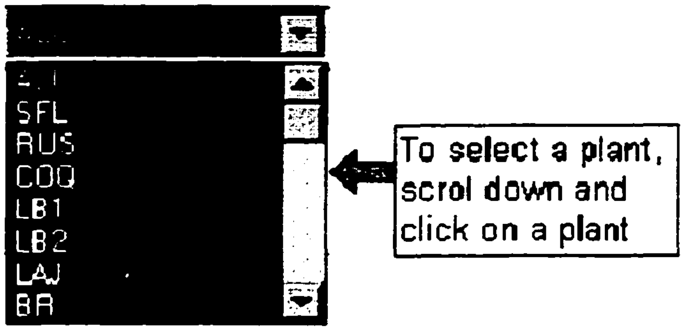


Figure D.5. Plant Selection for Setting User's Operational Limits

D.4.1. Modifying the Forebay Operational Limits

To modify the reservoir's forebay elevation operational limits as set in the LRB system, the user can press on the "Max Forebay" or the "Min Forebay" tab (Figure 7) and enter the set of new limits for each plant, for each hour in the study, as shown in Figure D.8. If the user enters a forebay limit outside the range specified in the LRB system, an error message is displayed indicating that the number entered is outside the range. Figure D.6 illustrates such an error message for one reservoir.

Figure D.6. Maximum Forebay Level Out of Range Error Messages

Figure D.7 GUI Optional Operational Limits

D.4.2. Modifying the Scheduled Spill Discharges

Similarly, the user can adjust the scheduled spills from a reservoir, for each time step, by pressing on the "Scheduled Spills" tab, as shown in Figure D.8. The default values for spills are read from the LRB system. If the user modifies these spills, they will replace the ones generated by the LRB system and will be used in the simulation and optimization run.

D.4.3. Setting the Plant's Discharge Operational Limits

The user can also set the maximum and minimum total plant discharges (turbine and spill) by pressing on the "Max Discharge" or the "Min Discharge" tabs. The default values are set at 1000000 and –1000 cubic meters per second for the maximum and minimum plant discharge respectively, as shown in Figure D.9.

D.4.4. Modifying the Minimum Generation Operational Limits

The "Min Generation" tab displays the minimum generation limits as read from the LRB system for each plant, as shown in Figure D.10. If the user modifies these limits, they will replace those generated by the LRB system and will be used in the optimization run.

D.4.5. Files Generated

If the user selects one or more of the above optional features, change the limits. and save them, a text file(s) containing the modified hourly data is generated and transferred to the simulation model. In addition, the GUI generates a text "Control" file that informs the simulator, among other things, if the user has modified any of the optional operational limits. The new operational limit files are saved at the client side workstation and after the GUI session ends they are transferred to the NT server by the communication protocols. When the modeling process starts at the NT Server, the simulator writes out the user specified operational limits for use in the optimization model. A sample control file has been included at the end of this Annex D for reference.

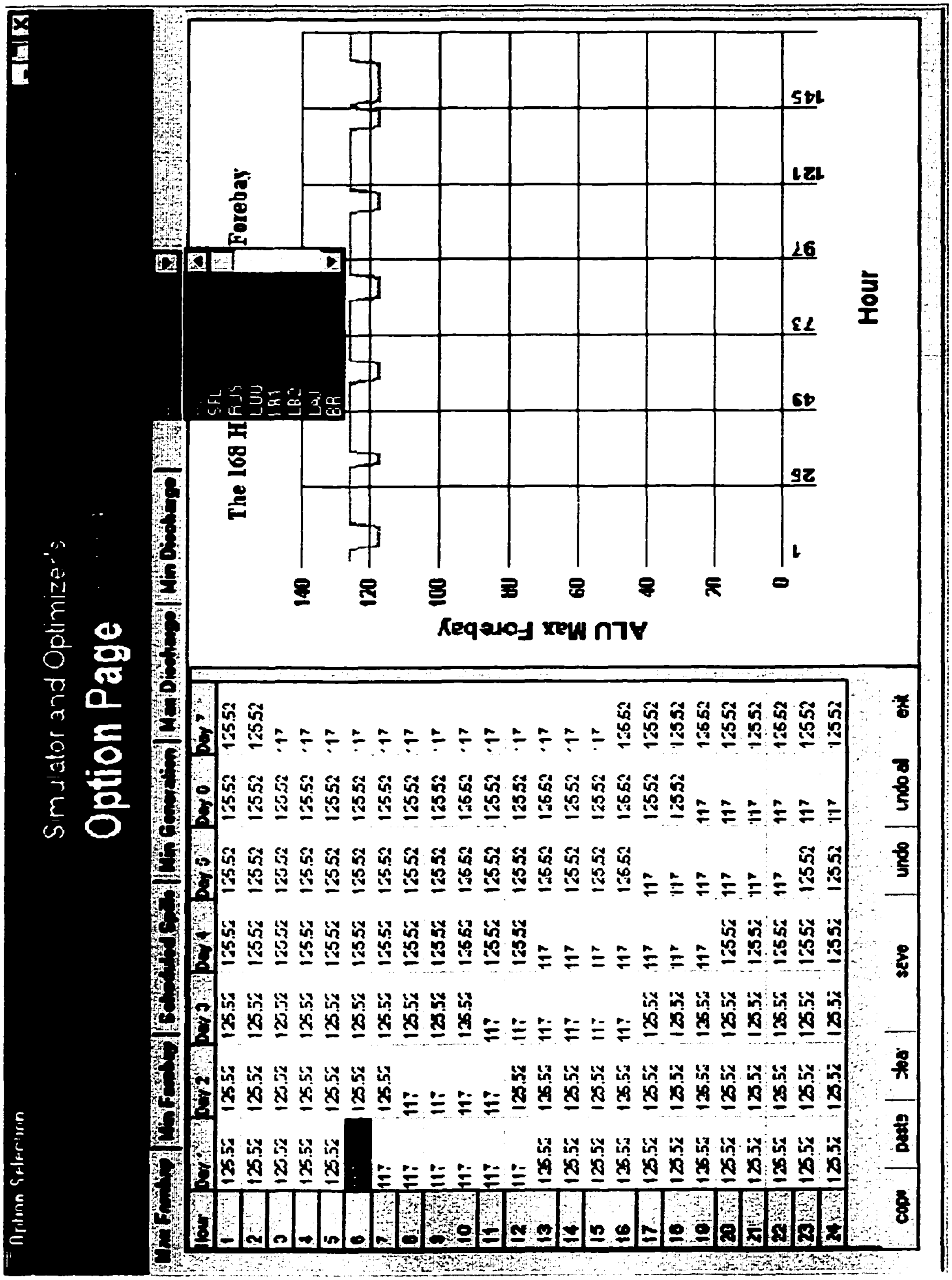


Figure D.8. GUI Optional Operational Limits: Maximum Forebay Level

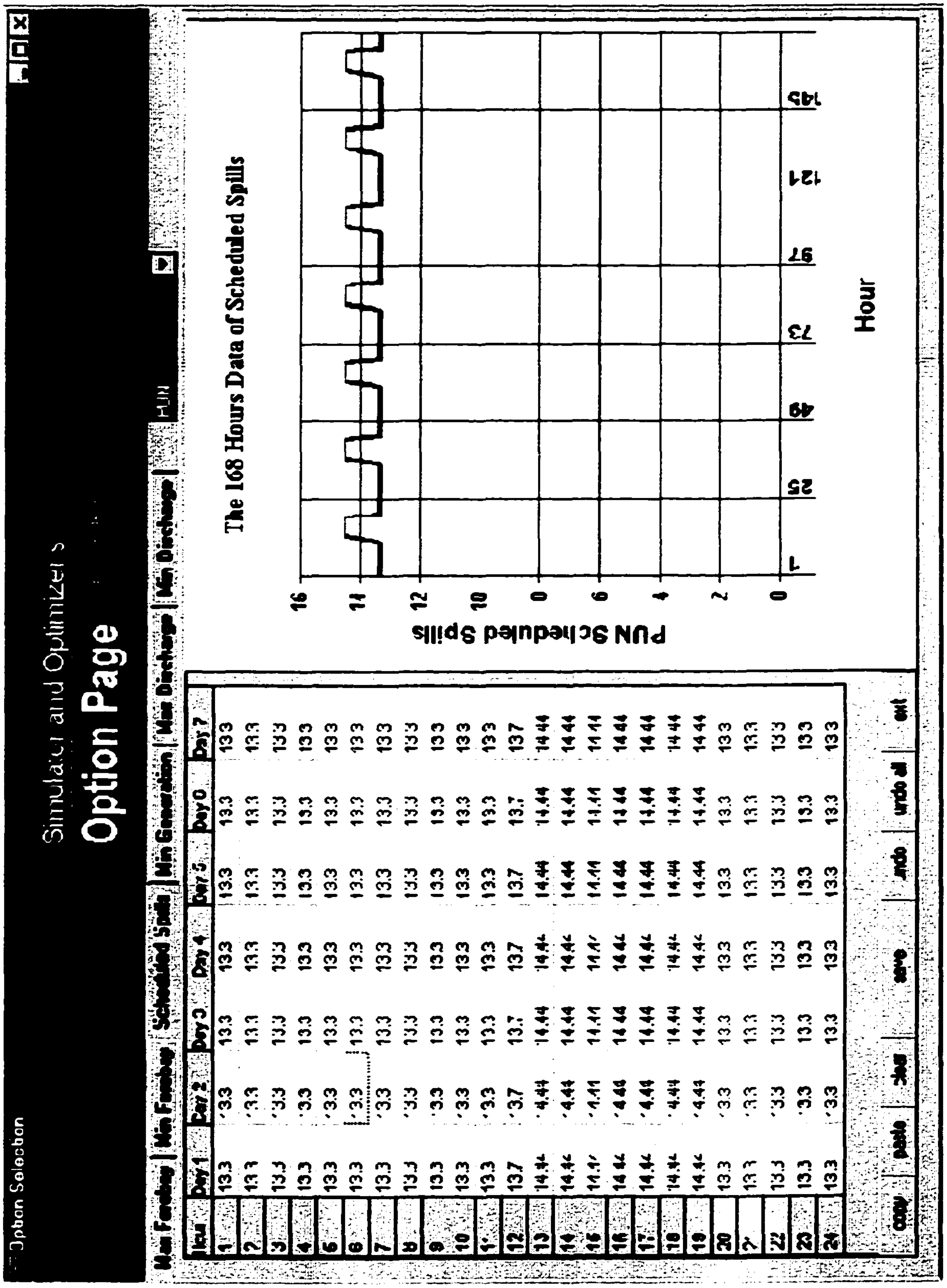


Figure D.9. GUI Optional Operational Limits: Spills

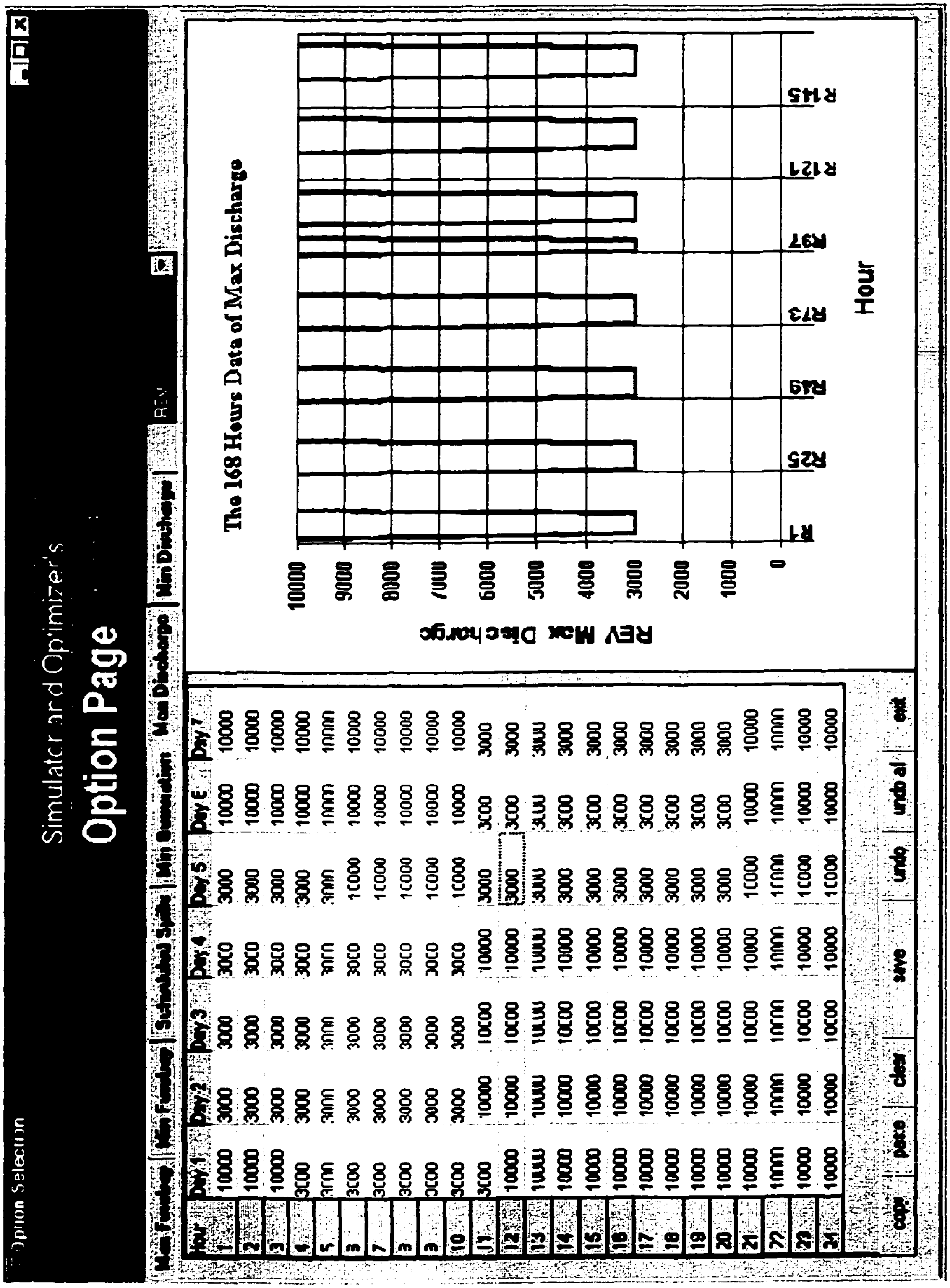


Figure D.10. GUI Optional Operational Limits: Maximum Plant Discharge Limit

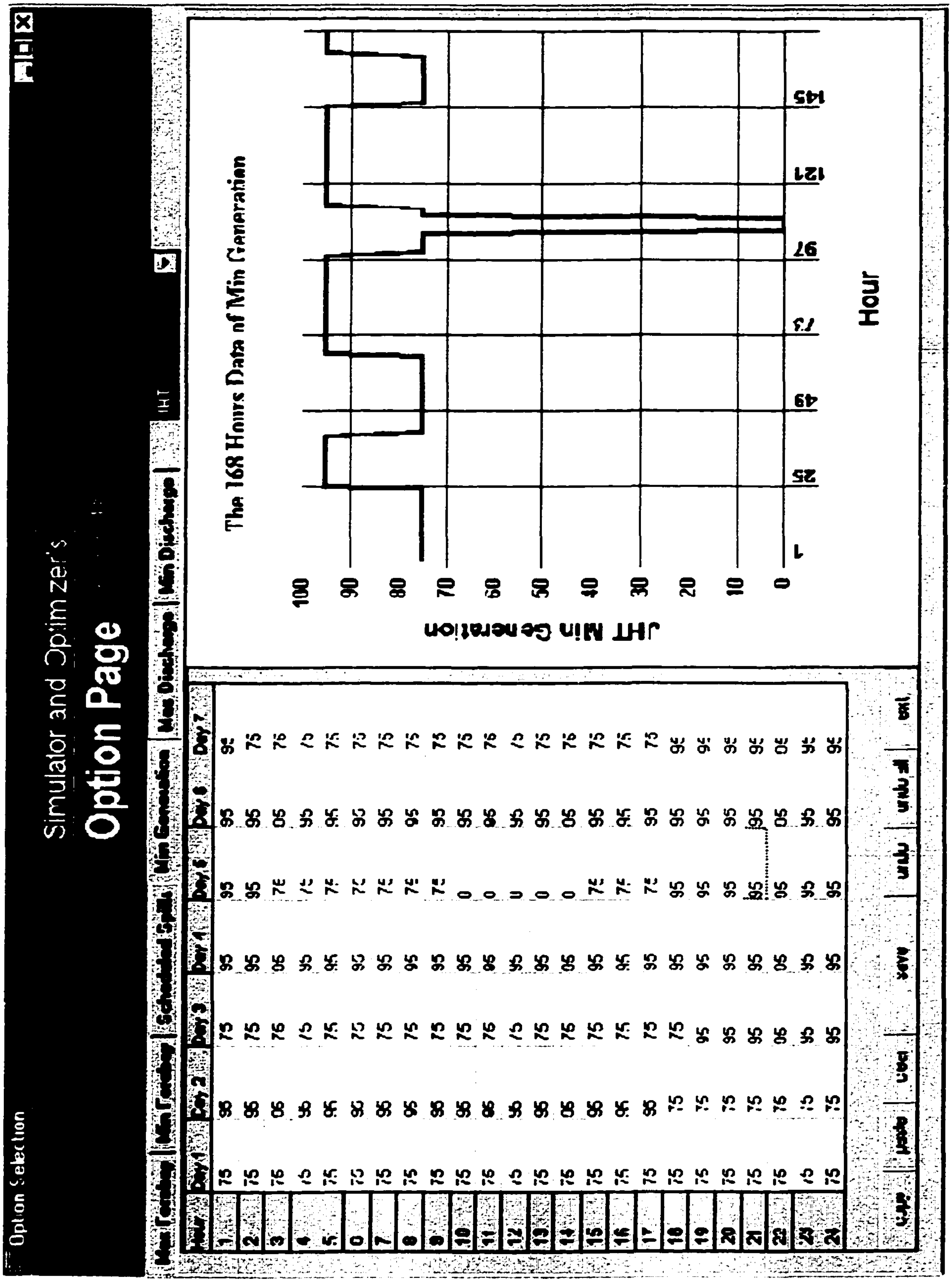


Figure D.11. GUI Optional Operational Limits: Minimum Generation Limit

D.5. Setting the Optimization Objective Function

The user can select one of four objective functions for the optimization study by pressing on the drop-down menu and scrolling to the desired objective function as shown in Figure D.12. For each objective function, except Min_QHK, a set of input parameters is required as described below. Once the user completes the input session, the selected objective function is written to the control file.

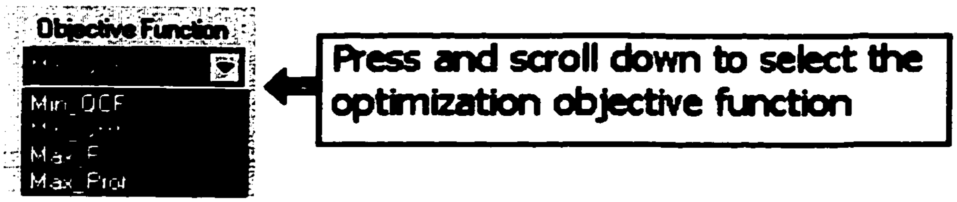


Figure D.12. Selecting the Optimization Objective Function

D.5.1. Minimize the Cost of Water Used Objective Function

This objective function minimizes the cost of Water discharged from the optimized plants weighted by a Cost Factor (CF). CF is a user input parameter for each plant, and it reflects the cost of Water to be used for power generation and other purposes from each plant. A high CF corresponds to more costly water, or more valuable water, from the corresponding plant. This objective function would typically be used when the user prefers to have more control over the amount of water to be used from each plant in a river system, particularly from the upper most reservoir (e.g. the Kinbasket in the Columbia, or the Williston in the Peace). If the user wishes to use more water from a particular plant or river system, then lower CF values would be assigned to the plants in that river system. The default CF values are determined by dividing 1.0 by the number of plants selected for optimization. Although it is a good practice to normalize the CF values to add up to 1.0, it is not a requirement. If the user has access to the marginal cost of Water for each plant (in S/cubic meters) in the optimization study, these values can be entered, and the optimization study will then minimize the relative value of the plant discharges used to meet the load. Once the user has input the CF values for each plant in the optimization study, and presses the "Save" button as shown in Figure D.13, a text file is generated by the GUI. This file lists the optimized plant identification and the corresponding CF values in AMPL syntax. In addition the GUI generates the control file as illustrated in Annex D. Thereafter, the optimization study will be initialized by running the client side communication protocol in a DOS Windows session. The client side communication protocol alerts the server communication protocol and compresses and transfers input data to the NT Server. When the optimization study is complete, the client communication protocol takes over, launches the Results-Display Software and the Results Dialogue Form, and terminates itself and the DOS Windows session.

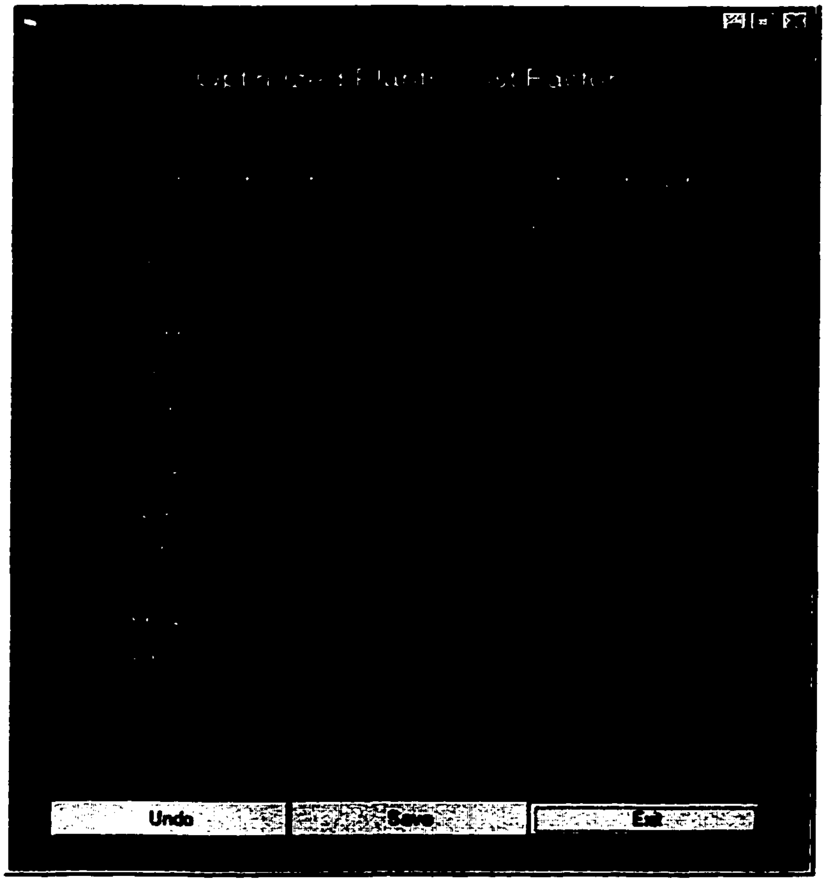


Figure D.13. The Cost Factor User Input Form for Min_QCF Objective Function

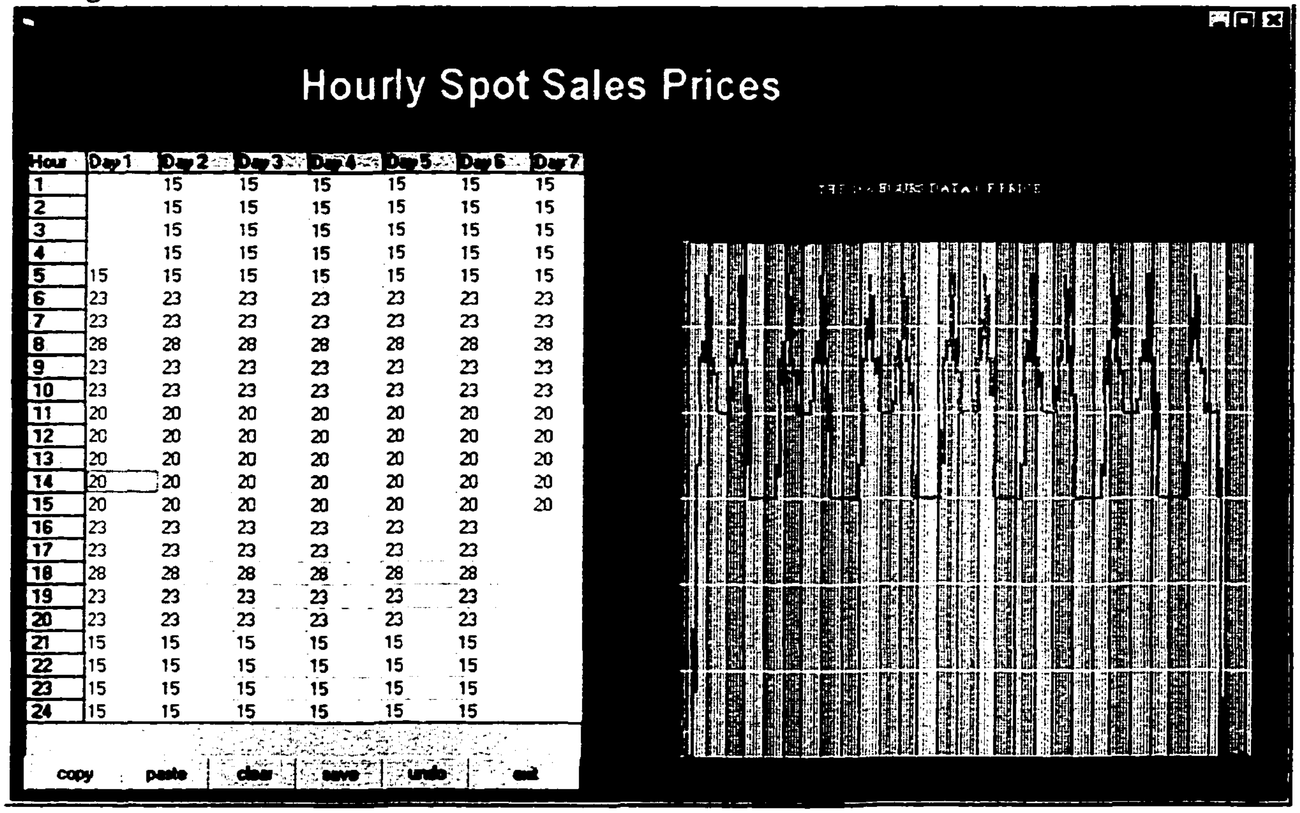
D.5.2. Maximize the Efficiency Objective Function

This objective function uses the hydraulic value H/K to weigh the turbine discharges from each plant. It minimizes the total water discharged from the turbines and the spills weighted by the H/K factors. In its current setting, this objective function would typically be used when the user would like to maximize the efficiencies of the optimized plants. The H/K values are used as a proxy for the plant's efficiency, and they are calculated by dividing the plant's generation by its turbine discharge. The optimization model calculates the H/K values internally and corrects for head variations in each run. Once the user presses the "OK" button, the GUI generates the control file as illustrated in Annex D. Thereafter, the optimization study will be initialized by running the client side communication protocol in a DOS Windows session. The client side communication protocol alerts the server communication protocol and compresses and transfers input data to the NT Server. When the optimization study is complete, the client communication protocol takes over, launches the Results-Display Software and the Results Dialogue Form, and terminates itself and the DOS Windows session.

D.5.3. Maximize the Power Production Objective Function

This objective function maximizes the value of the additional power that could be generated in the study, provided that target reservoir levels at the end of the study are met. The target reservoir levels are determined by simulating the forebay levels given the LRB generation schedule, spills and the reservoir inflows. This objective function would typically be used when the user would like to maximize the short-term revenues from spot sales. It should be noted that when this objective function is used, the terminal reservoir levels are fixed at their specified values.

When the "OK" button is pressed, the "Hourly Spot Sales Prices" form is displayed as shown in Figure D.14. The form prompts the user to input the expected spot price structure for the extra power that could generated and sold in the spot market for the study period. These prices will influence the hourly distribution of the extra power that can be generated. Once the GUI session ends it writes the spot prices to a text file in AMPL syntax and generates the control file. Thereafter, the optimization study will be initialized by running the client side communication protocol in a DOS Windows session. The client side communication protocol alerts the server communication protocol and compresses and transfers input data to the NT Server. When the optimization study is complete, the client communication protocol takes over, launches the Results-Display Software and the Results Dialogue Form, and terminates itself and the DOS Windows session.



Hour	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7
1		15	15	15	15	15	15
2		15	15	15	15	15	15
3		15	15	15	15	15	15
4		15	15	15	15	15	15
5	15	15	15	15	15	15	15
6	23	23	23	23	23	23	23
7	23	23	23	23	23	23	23
8	28	28	28	28	28	28	28
9	23	23	23	23	23	23	23
10	23	23	23	23	23	23	23
11	20	20	20	20	20	20	20
12	20	20	20	20	20	20	20
13	20	20	20	20	20	20	20
14	20	20	20	20	20	20	20
15	20	20	20	20	20	20	20
16	23	23	23	23	23	23	
17	23	23	23	23	23	23	
18	28	28	28	28	28	28	
19	23	23	23	23	23	23	
20	23	23	23	23	23	23	
21	15	15	15	15	15	15	
22	15	15	15	15	15	15	
23	15	15	15	15	15	15	
24	15	15	15	15	15	15	

Figure D.14. Spot Prices for the Max_P Objective Function

D.5.4. Maximize the Profit Objective Function.

This objective function is intended for use in the Shift Office in real-time operations mode. It makes the optimal tradeoff between the present benefits (represented by spot sales) with the expected long-term value of energy in storage (represented by the marginal value of stored water in reservoirs). The present formulation includes the value of spot sales to the U.S. and to Alberta, and the values of deviations from reservoir target levels. The target levels are as set by the user in the GUI (see the "Drop Target" input form shown in Figure D.19). The values of the deviation from the target level are calculated by multiplying the marginal value of water (MVW) by the volume of deviation for each plant. The MVW for the optimized plants is calculated in the model using the marginal value of energy, which is a user-input parameter specified in the GUI's "Rbch" input form shown in Figure D.17. The value of spot sales are calculated by multiplying the optimized net spot trading schedules by the spot price in each market as specified by the user in the GUI "Spot Prices/Trans. Capacity" input form shown in Figure D.18.

D.5.4.1. Specifying the Plant's Marginal Value of Energy

The Rbch for the optimized plants is an input parameter that the user can specify using the GUI "Rbch" input forms shown in Figure D.15. The unit for Rbch is in dollars per MWHr. The default values for Rbch are read from a default text file that could be generated by any other application (e.g., other optimization models), and could reside anywhere in the B.C. Hydro computer network. The user can change these values to reflect the current marginal value of energy for each optimized plant, or to perform what-if-analysis. The GUI writes Rbch to a text file in AMPL syntax (e.g., `param Rbch:= GMS 35;`).

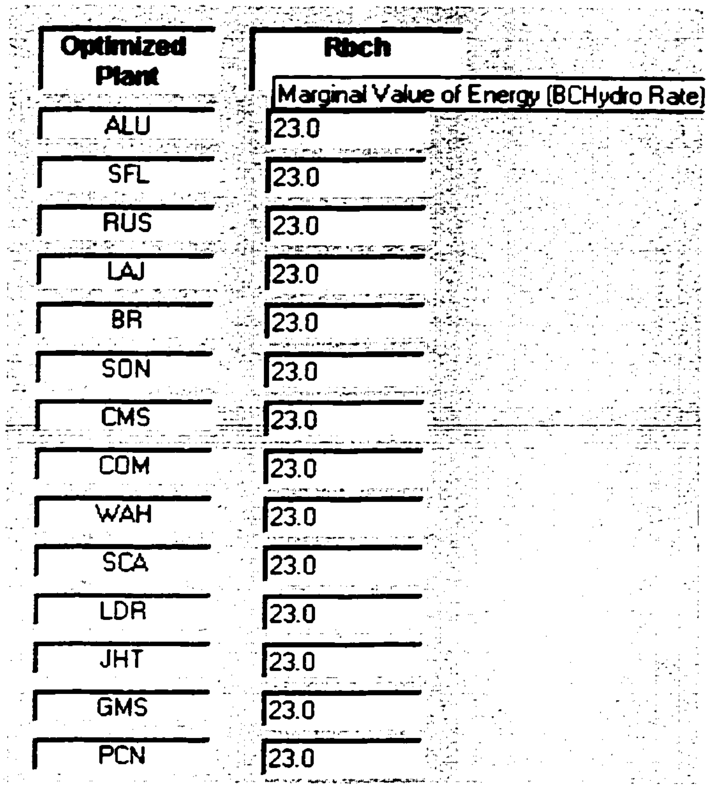


Figure D.15. Setting the Marginal Value of Energy (Rbch)

D.5.4.2. Specifying the Plant's Forebay Target

As shown in Figure D.16, the Drop Target GUI input form allows the user to drop the forebay target level in the last time step for any optimized plant in the study. If the user checks the box next to the plant name (e.g., GMS), then the constraint that fixes the plant's simulated forebay elevation using the LRB scheduled generation will be dropped, thus giving the optimization model the freedom to fluctuate within the plant's operational limits. If, however, the box is not checked, the optimization model constraint that fixes the last time step forebay target will be enforced.

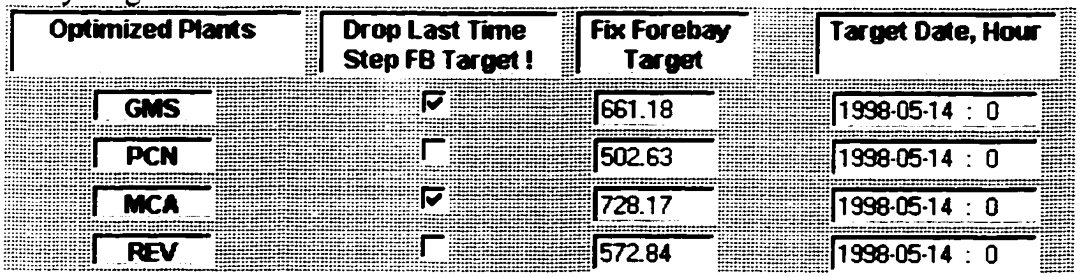


Figure D.16. Setting the Reservoir's Target Forebay Levels

The fix forebay target and target date and hour allow the user to set a forebay target value and a time step within the study period. This forebay elevation, target date and hour are used in the optimization model to calculate the deviation in reservoir storage. Using the Rbch, the marginal value of water is calculated in the model and the value of the deviation in reservoir storage will be determined and used in the objective function. The GUI write two text files in AMPL syntax for later use by the optimization model. One file contains the constraints imposed by the user on the last time step forebay target level (e.g., "`drop LRB_STORAGE ['GMS'];`"), and the other contains the forebay target level and the corresponding hour in the study for the target (e.g., "`param: Target_FB Target_Hr := GMS 661.18 24;`"). The default values for the forebay level and hour are set to correspond to the last time step in the study and are currently obtained from the LRB system.

D.5.4.3. Specifying the Available Transmission Capacity and Spot Prices

The optimization model includes a set of constraints that limit the net spot trading schedules to the U.S. and Alberta to the available transmission tie line capacities (ATC). As shown in Figure D.18, the GUI allows the user to review and change the hourly forecast ATC values, which are provided, electronically, each hour by PowerEx to the LRB system. To enable the user to perform what-if-analysis, the user can also specify the tie line capacity limits for each day, for each market, and for predetermined blocks of hours representing peak, high, and low load hours. The GUI writes the hourly ATC values to a text file in the AMPL syntax for later use by the optimization model.

As shown in Figure D.19, the "Spot Prices/Trans. Capacity" input form in the GUI allows the user to review and modify PowerEx's forecast average spot prices in the U.S. and Alberta electricity markets (Alberta prices are in Canadian $, and the U.S. are in U.S. $). For each day in the study, these spot prices are displayed and can be modified by the user. To enable the user to perform what-if-analysis, the user can also specify one price structure for each day, for each market, and for predetermined blocks of hours representing peak, high, and low load hours. The input form lists and graphically displays the 24 hour spot price structure for net trading schedules to the US and Alberta. The GUI writes the spot price values to a text file in AMPL syntax for later use by the optimization model.

D.5.4.4. Specifying the Operating Reserve Obligation and Regulating Margin

As shown in Figure D.20, the GUI allows the user to specify two real-time operational parameters: the fraction of operating reserve obligation (ORO) for each optimized plant, and the minimum regulating margin requirement (RMR) for all optimized plants. These requirements are set by the WSCC for reliability purposes in the interconnected system in the Pacific Northwest region. The ORO (in MWHr) for each plant is calculated in the model by multiplying the ORO fraction by the optimized plants' generation. The optimizer determines the optimal distribution of the RMR among the optimized plants (see Section 4.5 for more details). The GUI writes the ORO and the RMR to a text file in the AMPL Syntax for later use by the optimization model (e.g., "`param G_Min_BUFFER := 200;`", `param G_ORO := GMS 0.05;`"). This form also contains the exchange rate from Canadian to U.S. dollars, for use in the optimization model for currency conversion.

Once the GUI session ends the optimization study will be initialized by running the client-side communication protocol in a DOS Windows session. The client side communication protocol alerts the server communication protocol and compresses and transfers input data to the NT Server. When the optimization study is complete, the client communication protocol takes over, launches the Results-Display Software and the Results Dialogue Form, and terminates itself and the DOS Windows session.

D.6. The Control File Data Structure

As indicated in many instances in this section, the control file is a text file generated by the GUI to convey the user's specifications of the simulation and optimization study. As illustrated in Annex D, the control file contains the following information.

- The **Start Date**, which specifies the date of the study;
- The **Start Hour**, which specifies the first hour in the study;
- The **Number of Hours** in the study;
- The **Number of Plants** that the simulation run includes;
- The **Override**, which informs the simulator which of the optional operational limits has been set by the user. This message is conveyed by means of a binary number, with "1" indicating that the limit has been modified by the user, and "0" indicating no user limits have been set;
- The **Objective Function** chosen by the user. The abbreviated objective function name have been used for this purpose;
- The **SimAlone** information causes the simulator to either run solo "0", or with the optimizer "1". If run solo, the simulator does not write or read any of the optimizer's input or output files;
- The **Plant ID**, identifies the plant names included in the study, while the number following the ID represents the **initial forebay** level, and the **binary** number that follows the forebay indicates whether the plant is to be optimized or simulated. A "0" indicates that the plant is to be optimized, while a "1" indicates that the plant is to be simulated;
- Finally, the River system name included in the study is listed for use by the simulator and optimizer in the modeling process.

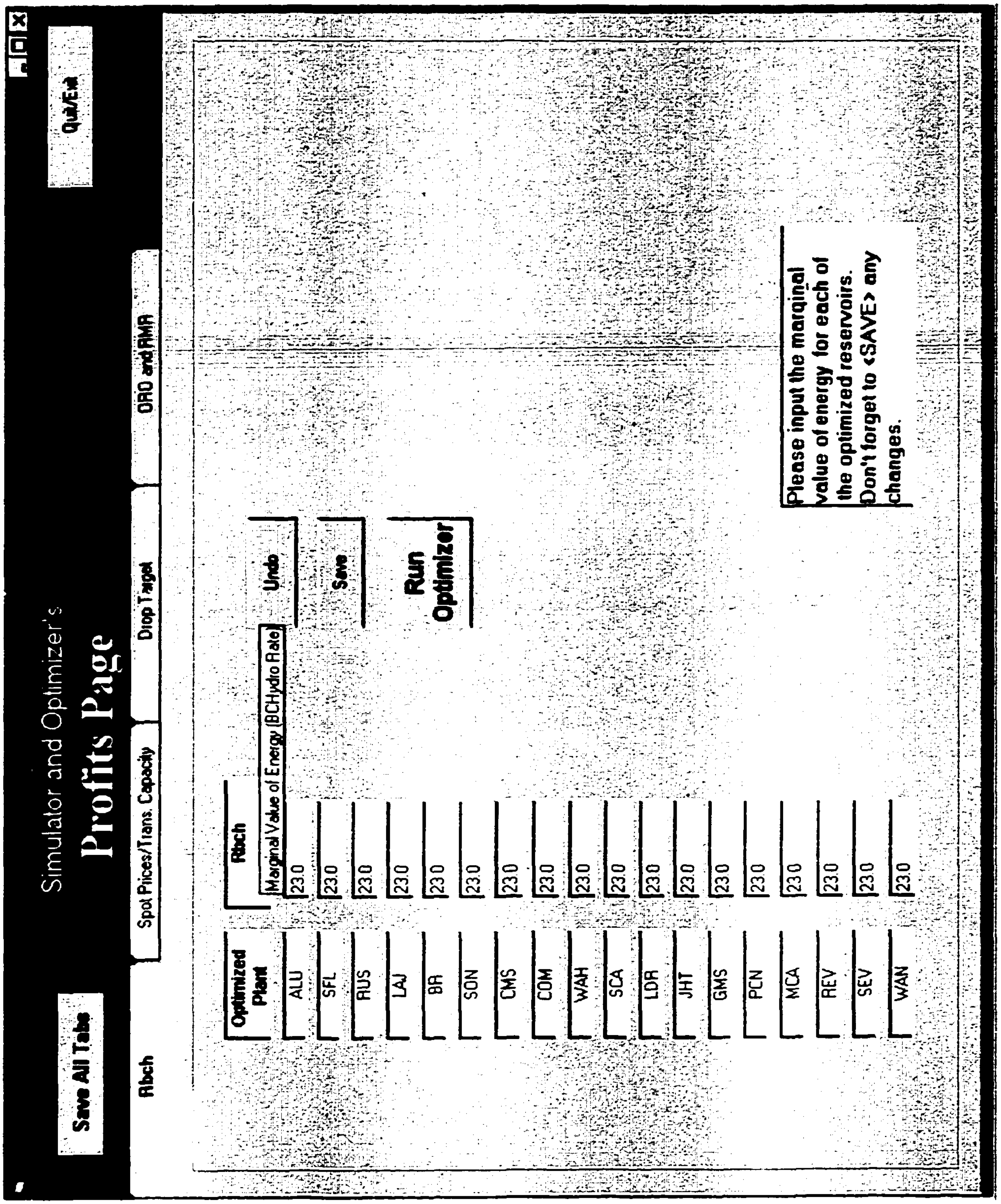


Figure D.17. Maximize Profit Objective Function: Rate for B.C. Hydro (Rbch) Input Form.

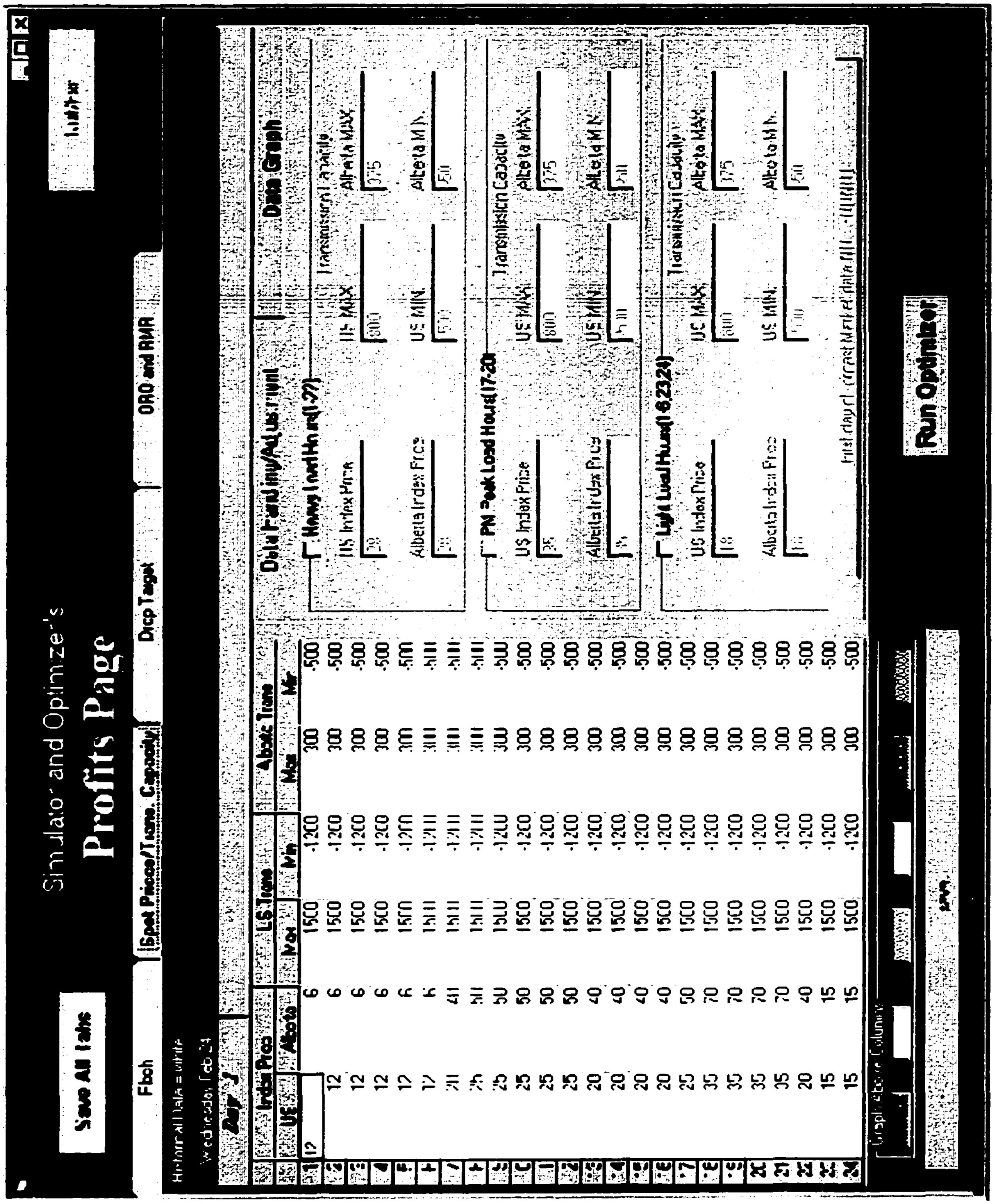


Figure D.18. The Maximize Profit Objective Function: Marketing Information

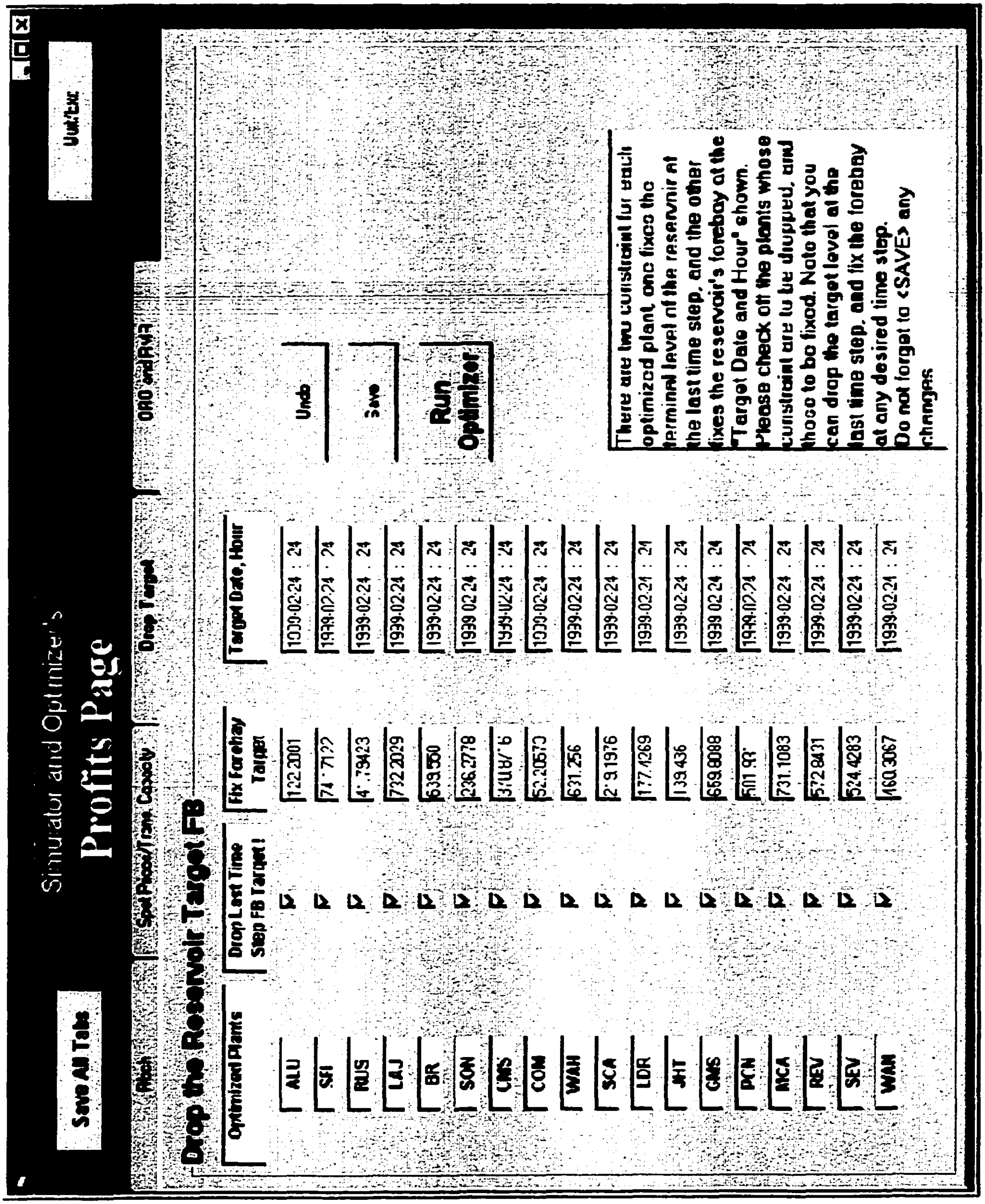


Figure D.19. The Maximum Profit Objective Function: Drop & Fix Forebay Target Levels Input Form

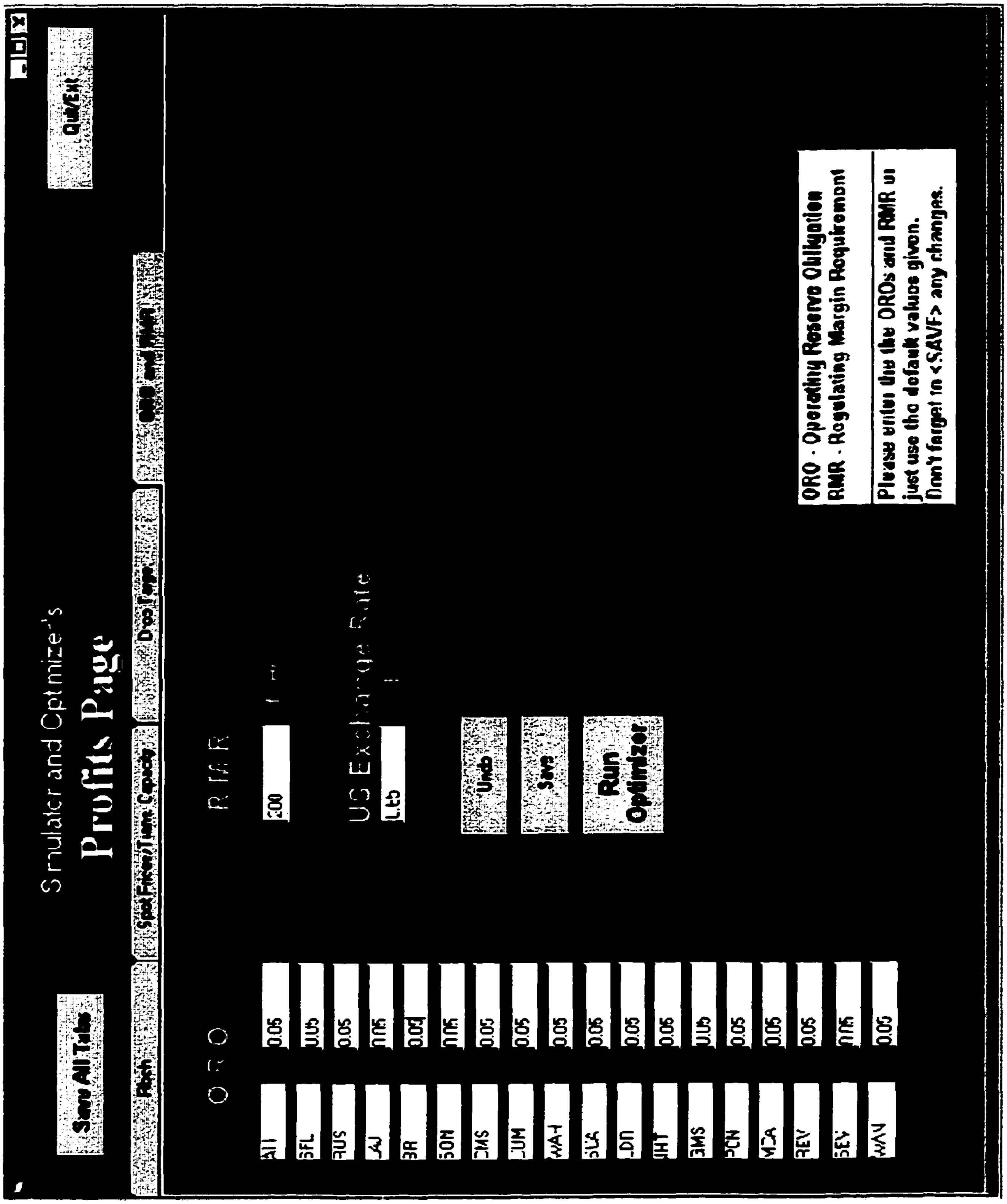


Figure D.20. The Maximum Profit Objective Function: Operating Reserve and Regulating Margins Input Form

D.7. Data Structure of the GUI Control File

```
Start Date    = 19990115
Start Hour    = 12
No. of Hours = 54
No. of Plants= 19
Override      = 1 0 0 0 1
Objective     = Max_Prof
SimAlone      = 0



ALU      117.770 0
SFL      76.4399 0
RUS      42.3717 0
LAJ      747.489 0
BR       644.329 0
SON      236.254 0
CMS      372.600 1
COM      50.9899 1
WAH      637.470 0
SCA      214.250 0
LDR      177.351 0
JHT      139.250 0
ASH      319.016 1
GMS      667.940 0
PCN      502.690 0
MCA      744.493 0
REV      572.809 0
SEV      524.609 0
WAN      462.000 0

Stave
Bridge
Cheakamus
Clowhom
Wahleach
Campbell
Ash
Peace
Columbia
PendOreille
```

ANNEX E
PROCEDURE TO DETERMINE THE OPTIMAL UNIT COMMITMENT

ANNEX E
PROCEDURE TO DETERMINE THE OPTIMAL UNIT COMMITMENT

The algorithm used to select the optimal combo is best explained in the following example. Suppose there are four units in a plant, and suppose that unit one and two are identical, the more efficient units three and four are also identical, and that the maximum generation for each unit is 460 MW. Suppose that the plant is required to produce 400 MWHr, and that the forebay level is at a given level. If all units are available for loading, then there are 15 possible unit combinations (2^4-1) that can satisfy the 400 MWHr load, if one ignores limits on the inoperable ranges. SPUC calculates the minimum turbine discharge for each unit combination that could be dispatched, for each plant loading, and forebay level, as listed in Table E.1. By inspection, it can be seen that if all units are available, then the optimal unit combination is either combo 4 or combo 8 (corresponding to dispatching units 3 or 4 respectively), since the turbine discharge to produce 400 MW for these combos is 249.1 m^3/s. Now if units 3 and 4 were not available, we would be left with combinations 3, 2, and 1, and the optimal combos are 1 and 2, 2, and 1 respectively. Table E.2, tabulates the complete set of optimal combos, for each unit availability for the above example. Also shown in the fourth column is the combo number that was stored in the preprocessed database. Although the selection of the combo number stored in the database could reflect some operational preferences (e.g., preferred unit's characteristics), its current use in STOM is for selection of the piecewise linear curve coefficients that represents the optimal combo.

Table E.1. Unit Combinations and Minimum Plant Discharge

Combo (Binary Number)	Plant Discharge for plant Loading at 400 MWHr at a given Forebay Level	Combo (Binary Number)	Plant Discharge for plant Loading at 400 MWHr at a given Forebay Level
1 (0001)	256.0	9 (1001)	255.3
2 (0010)	256.0	10 (1010)	255.3
3 (0011)	262.2	11 (1011)	261.7
4 (0100)	249.1	12 (1100)	266.8
5 (0101	255.3	13 (1101)	272.7
6 (0110)	255.3	14 (1110)	272.7
7 (0111)	261.7	15 (1111)	278.6
8 (1000)	249.1		

Table E.2. Unit Combinations and Optimal Unit Commitment

Available Combo	Binary Equivalent (U4, U3, U2, U1)	Set of Possible Combos in Available Combo	Minimum flow and optimal combos for plant Load of 400 MW and for a given Forebay
15	1111	15 14 13 12 11 10 9 8 7 6 5 4 3 2 1	249.1 (4, 8) → 8
14	1110	14 12 10 8 6 4 2	249.1 (4, 8) → 8
13	1101	13 12 9 8 5 4 1	249.1 (4, 8) → 8
12	1100	12 8 4	249.1 (4, 8) → 8
11	1011	11 10 9 8 3 2 1	249.1 (8) → 8
10	1010	10 8 2	249.1 (8) → 8
9	1001	9 8 1	249.1 (8) → 8
8	1000	8	249.1 (8) → 8
7	0111	7 6 5 4 3 2 1	249.1 (4) → 8
6	0110	6 4 2	249.1 (4) → 8
5	0101	5 4 1	249.1 (4) → 8
4	0100	4	249.1 (8) → 8
3	0011	3 2 1	256.0 (1, 2) → 2
2	0010	2	256.0 (2) → 2
1	0001	1	256.0 (1) → 1

The above procedure is repeated for all load increments and for all forebay levels to produce for each plant, a database that is used by STOM to select the optimal unit commitment.

Once the optimal unit commitment is selected, the simulation is re-run, using the generation schedule computed by the linear programming model and new sets of coefficients for the piecewise linear generation production curves are computed for input to the next optimization run.

ANNEX F

RESULTS SOFTWARE GRAPHIC DISPLAYS

RUN FOR Feb. 24, 1999 96 Hours Max. Profit Objective Function — Print Summary

Hour	1	2	3	4	5	6	7	8	9	10	11	12
GMS Opt Generation (MWHr)	1966	1701	1576	1714	1576	1576	2006	2478	2477	2475	2482	2520
PCN Opt Generation (MWHr)	500	499	498	496	494	493	494	495	497	499	502	503
MCA Opt Generation (MWHr)	582	582	558	397	414	289	1171	1171	1171	1171	1171	1171
REV Opt Generation (MWHr)	185	185	185	185	185	185	302	1429	1429	1429	1416	1378
Residual Generation (MWHr)	1377	1355	1336	1348	1455	1833	2207	2340	2352	2359	2355	2367
Prescheduled Exports (MWHr)	0	0	0	0	0	64	270	307	299	51	14	147
Prescheduled Imports (MWHr)	485	516	566	556	516	0	0	0	0	0	0	0
Spot_US (MWHr)	-51	-20	-20	-70	-70	-419	-133	791	555	860	776	761
Spot_AB (MWHr)	-540	-540	-540	-500	-540	-725	75	75	75	75	260	260
Import (MWHr)	1076	1076	1126	1126	1126	1144	133	0	0	0	0	0
Export (MWHr)	0	0	0	0	0	64	345	1173	929	986	1050	1168
Extra Power Generated (MWHr)	0	0	0	0	0	0	0	0	0	0	0	0
LRB Energy Use (MWHr)	3859	3577	3421	3408	3321	3749	4082	4754	5021	4651	4540	4794
Optimized Energy Use (MWHr)	3250	2970	2818	2825	2693	2587	3983	5644	5642	5640	5637	5640
Hourly energy gain (MWHr)	608	607	603	583	628	1162	98	-890	-621	-989	-1097	-846

Hour	13	14	15	16	17	18	19	20	21	22	23	24
GMS Opt Generation (MWHr)	1945	1783	1745	1717	2474	2473	2472	2471	2469	1984	1964	1986
PCN Opt Generation (MWHr)	503	502	500	498	499	500	501	502	503	502	502	503
MCA Opt Generation (MWHr)	1171	1171	1171	1171	1171	1171	1171	1171	1171	1171	582	308
REV Opt Generation (MWHr)	302	302	302	302	1429	1429	1429	1429	1429	642	242	120
Residual Generation (MWHr)	2367	2384	2356	2419	2393	2364	2400	2398	2415	2444	1846	1729
Prescheduled Exports (MWHr)	147	13	13	1	0	52	235	72	0	0	0	0
Prescheduled Imports (MWHr)	0	0	0	0	0	0	0	0	0	0	247	248
Spot_US (MWHr)	-808	-674	-674	-662	941	373	36	318	643	-335	-419	-418
Spot_AB (MWHr)	260	260	260	260	260	260	260	260	260	260	-540	-540
Import (MWHr)	808	674	674	662	0	0	0	0	0	335	1206	1206
Export (MWHr)	407	273	273	261	1201	685	531	650	903	260	0	0
Extra Power Generated (MWHr)	0	0	0	0	0	0	0	0	0	0	0	0
LRB Energy Use (MWHr)	4730	4404	4444	4416	4619	5220	5551	5309	4836	4517	3944	3574
Optimized Energy Use (MWHr)	3919	3748	3707	3677	5637	5635	5623	5621	5619	4296	3359	3021
Hourly energy gain (MWHr)	811	656	736	739	-1018	-416	-71	-312	-783	220	584	553

Total energy gained (MWHr)	2233
LRB Spot Value ($)	14,471
OPT Spot Value ($)	821,495

Plant	GMS	PCN	MCA	REV	Total
Total LRB generation (MWHr)	230589	56623	52607	49732	389551
Total optimized generation (MWHr)	187321	47631	78953	77192	391096
Difference in generation (MWHr)	-43268	-8992	26346	27460	1546

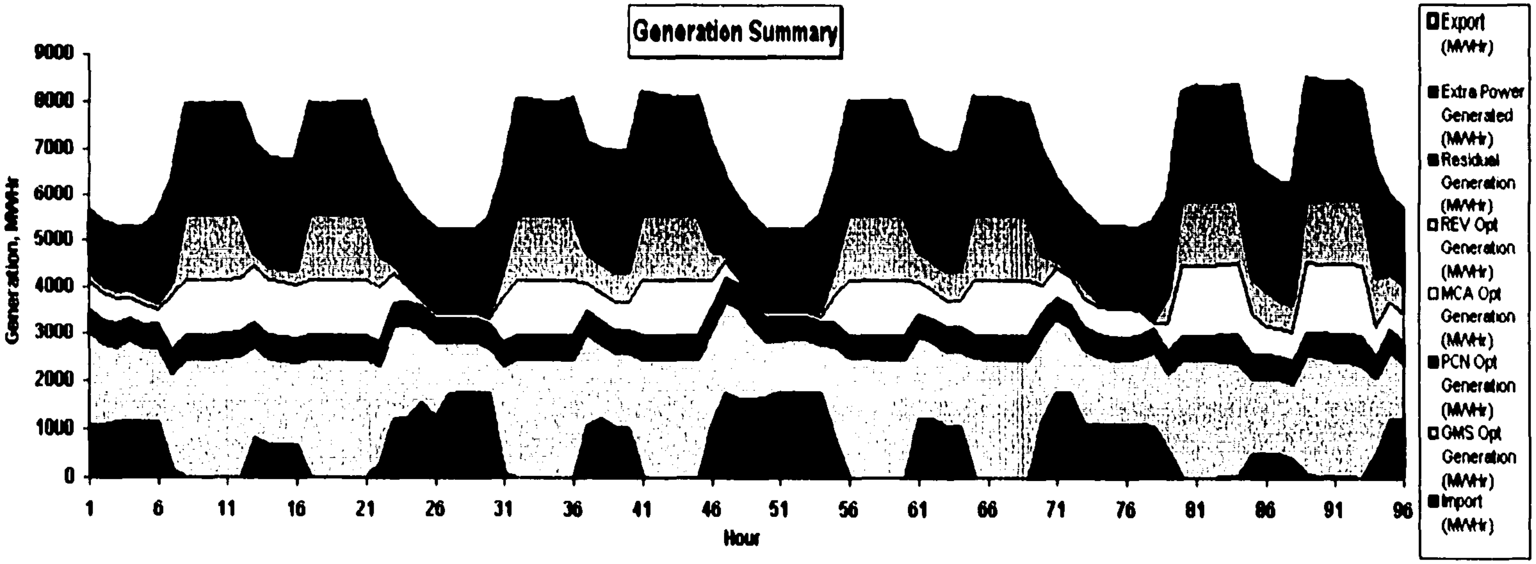


Figure F.1. Generation Summary.

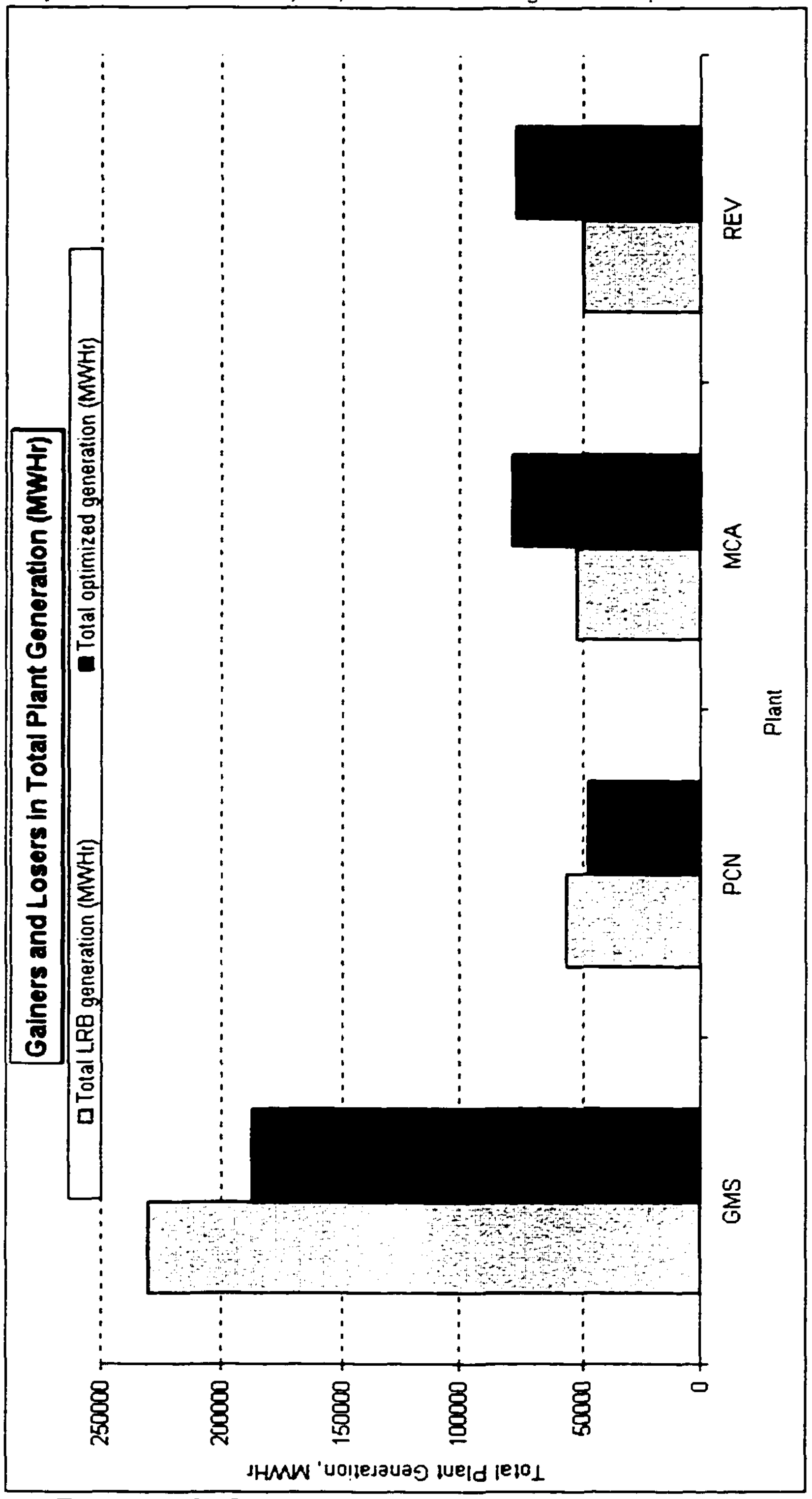


Figure F.2. Gainers and Loser in Total Generation

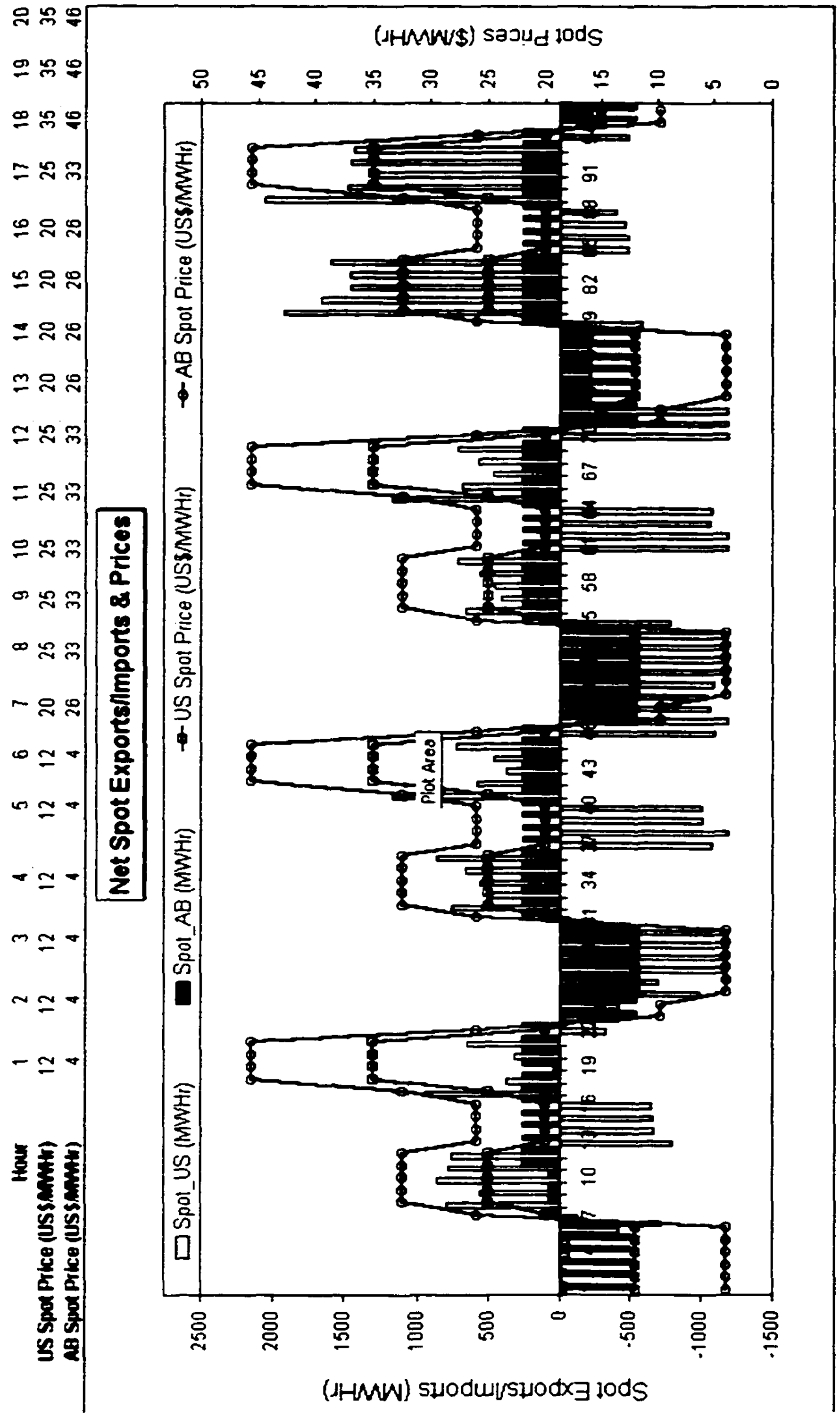


Figure F.3. Spot Prices and Optimized Trading Schedules in the Alberta and U.S. Markets

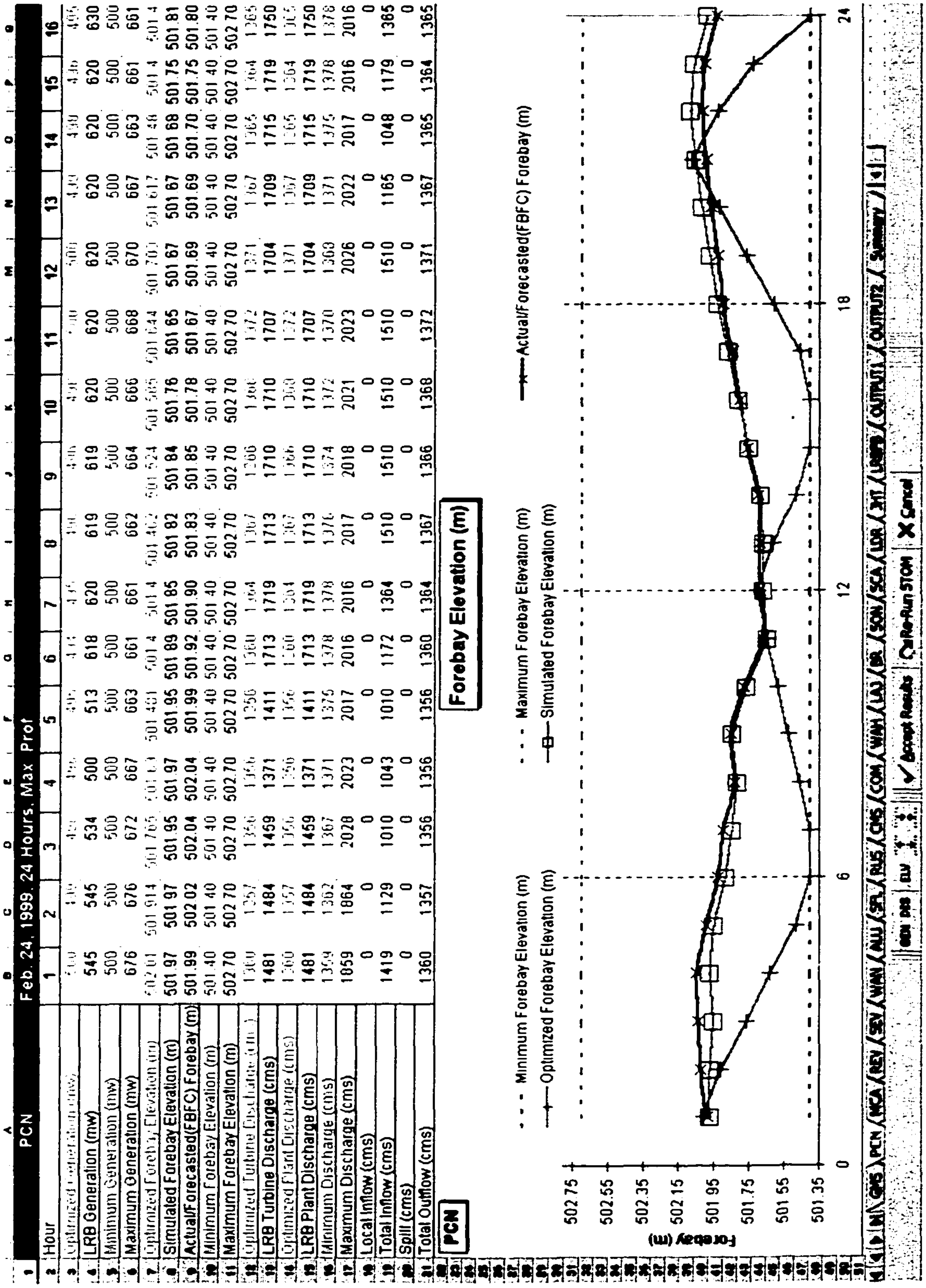


Figure F.4. Example Plant Forebay Elevations

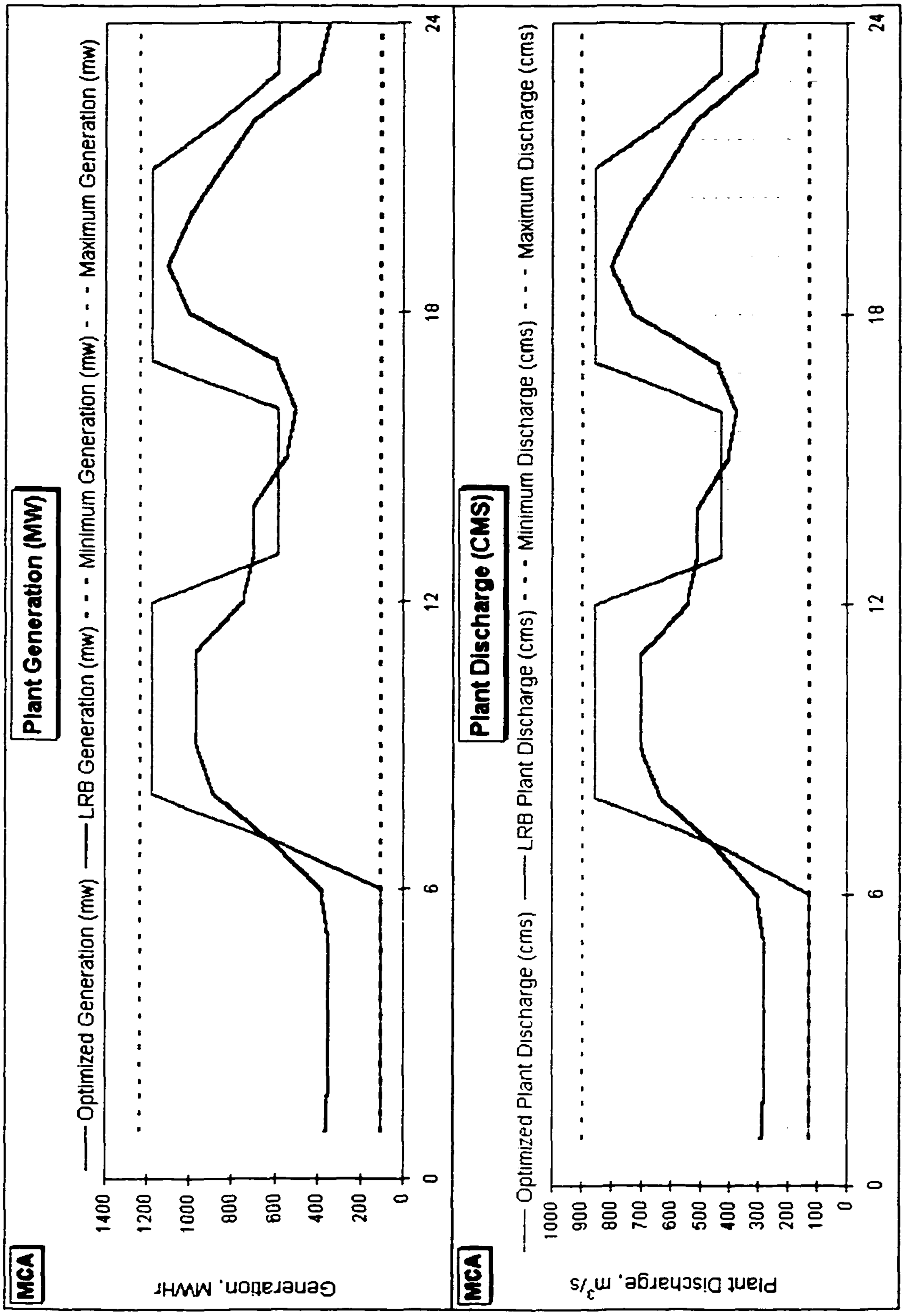


Figure F.5. Example Plant Generation and Plant Discharge

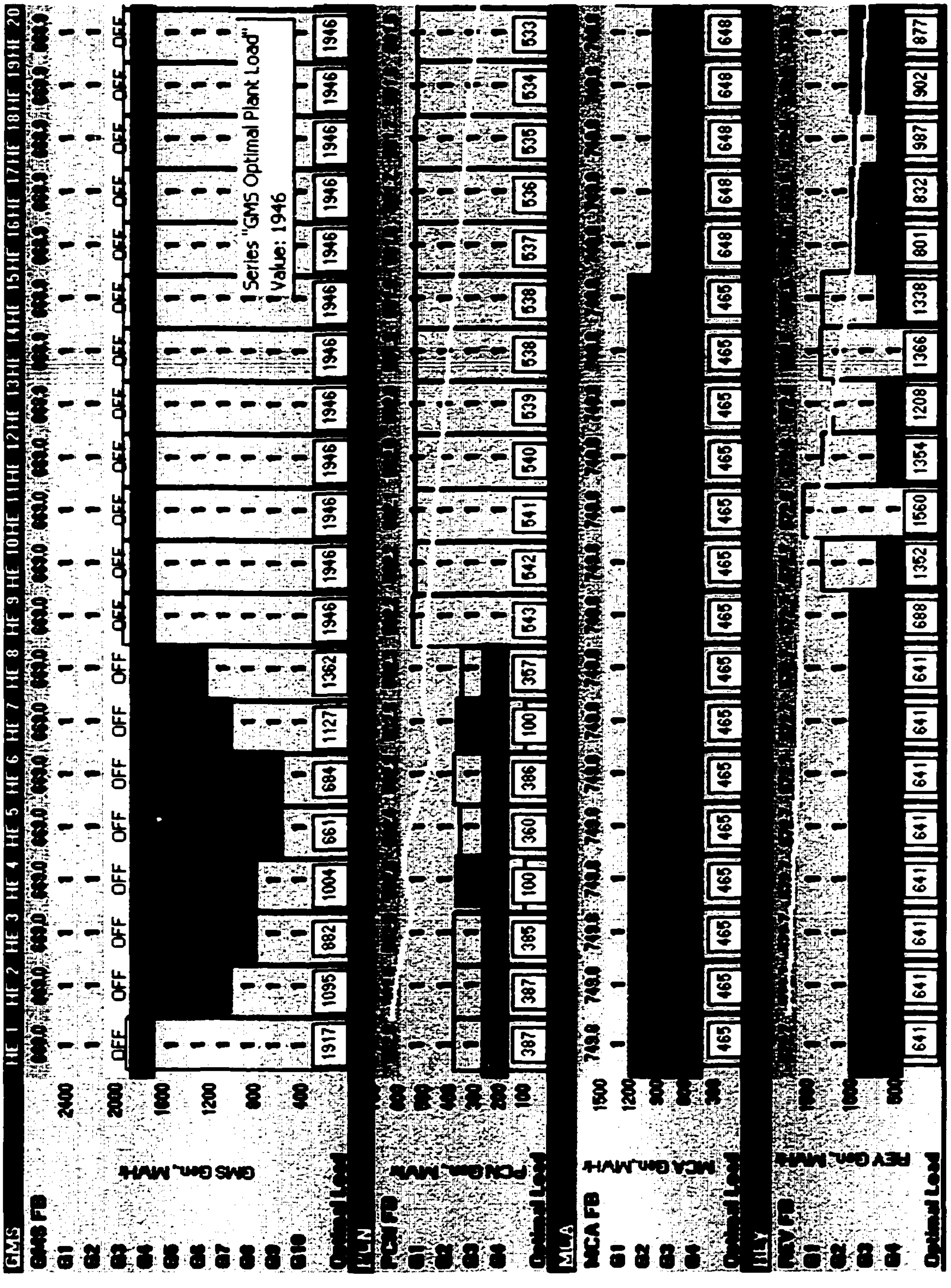


Figure F.6. Optimal Unit Commitment Schedule Derived by STOM

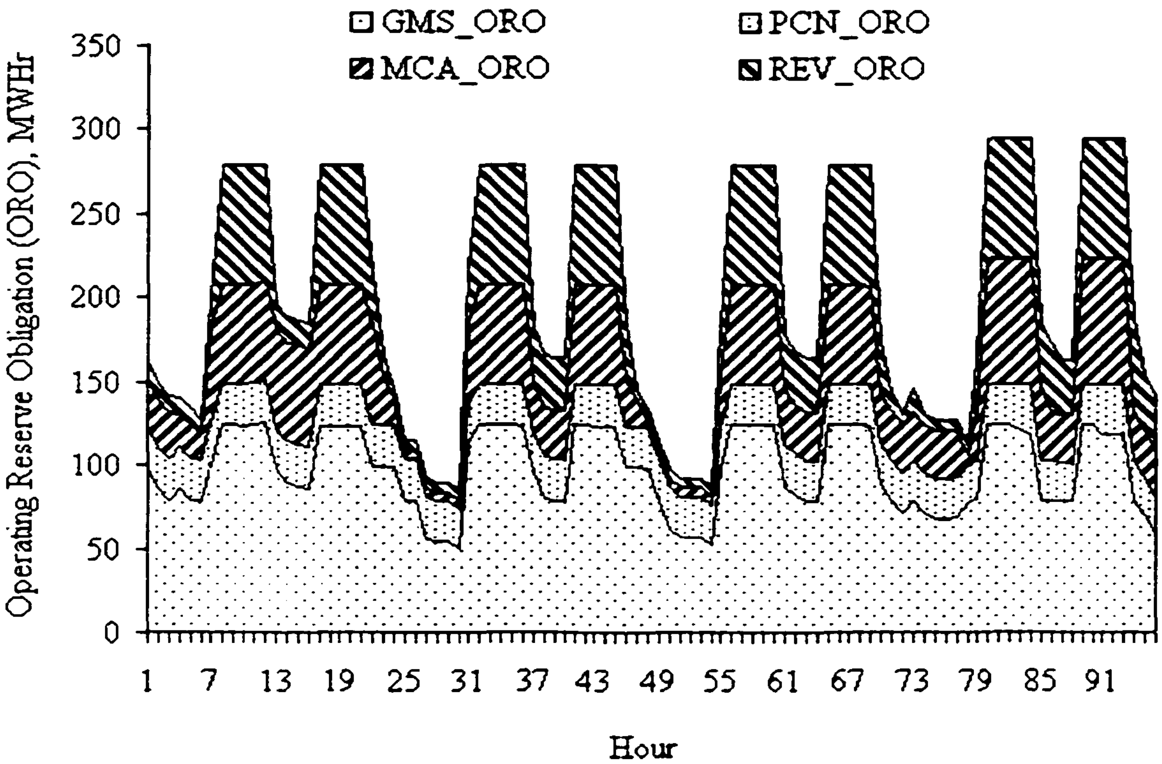


Figure F.7. Optimal Distribution of the Operating Reserve Obligation.

ANNEX G

MAIN OPERATIONAL FEATURES OF THE HYDROELECTRIC SYSTEMS CURRENTLY MODELED BY STOM

Annex G
Main operational features of the hydroelectric systems currently modeled by STOM

G.1 The Peace River System

The Peace system is located in north central B.C. region on the Peace River. The Peace complex consists of two reservoirs and two generating facilities. The Williston lake, which feeds the G.M. Shrum generating plant, is created by the 183 meter high W.A.C. Bennett Dam, and is the largest storage reservoir operated by B.C. Hydro with a surface area of 1788 km^2, total and live storage of about 74 and 40 billion cubic meters respectively. The catchment area of the Williston Lake is about 70,000 km^2, and it yields an estimated average runoff of 1072 m^3/s (1969-1991). The variability of inflows has been estimated to range from about 5,000 m^3/s to less than 300 m^3/s. Downstream of Williston lake and the G.M. Shrum plant lies the Dinosaur reservoir, which is comparatively a small reservoir with live storage capacity of about 216 million cubic meters, and average local inflows of about 8 m^3/s. Water from the Williston Lake is passed to the Gordon G. Shrum (known also as the Portage Mountain Project) plant, which is also the largest generating facility in the B.C. Hydro system, with a total generating capacity of 2730 MW. Outflows from the G.M. Shrum plant are discharged to the Dinosaur Reservoir. The Peace Canyon generating capacity is 700 MW, and it discharges to the Peace River. Figure G.1 illustrates the schematic layout of the Peace River hydroelectric facilities.

Due to the small storage capacity of the Dinosaur reservoir and the large discharge capacity of both the G.M. Shrum and the Peace Canyon generating facilities, the Dinosaur water levels can rise and fall rapidly in few hours. For this reason, and to avoid spills from the Dinosaur reservoir, both projects are operated in hydraulic balance. In addition, minimum releases between 142 and 283 m^3/s from the Peace Canyon generating facilities are required at various times of the year and are controlled by licenses and agreements to preserve fish stocks and domestic water supply pumps at downstream locations (Town of Taylor in B.C.). During the winter, the Peace River freezes over as very low temperatures in the region prevail. When ice breaks-up in spring, fragments of the ice cover could cause ice jams which, together with ice break-up in other tributaries, could cause flooding in downstream locations, particularly at the Town of Peace River in Alberta. For this reason, discharges from the Peace Canyon generating facility are kept at constant high levels during ice formation to maximize the hydraulic capacity of the river. Once the ice cover is formed, and until the ice breaks, wider fluctuations can be tolerated. Other operating constraints for the Williston Lake include impacts on forest industries (logging operations) and on dilution of effluents discharged into the Lake by the forest industry when the water level in the Lake drops below 654.1 meters.

In addition to being the largest plant, the G.M. Shrum generating facility is one of the most complex to hydraulically model in the B.C. Hydro system. For this reason an expanded discussion will be given here to illustrate the issues involved. As shown in Figure G.1, the G.M. Shrum generating facility consists of two powerhouses each with 5 generating units. The generating units in powerhouse no. 1 are all identical and of type 1, while the units in powerhouse no. 2 are of two different types, and are different from those in the first powerhouse. Turbine flows from each plant are discharged to a tailwater manifold (tunnel), which meets at the tunnel's exit to discharge into common tailwater pool. The water level of the tailwater pool depends on the water level of the Dinosaur reservoir. The generation efficiency for each unit depends on the height of water (gross head) on the turbines, calculated as the difference between the Williston Lake's water level near the entrance of the generators' intake and the water level at the powerhouse (known as the tailwater level). The complexity of modeling such an arrangement stems from the fact that each unit production depends on the status and generation of all other units in the facility, and on the water level of downstream reservoir. For example, to calculate unit no. 1 generation, given a certain generation level from all other units, an iterative procedure is needed to calculate the head on the five units in powerhouse 1. However, in order to calculate this head, the tailwater level (which is a function of the downstream reservoir's water level and the facility's total water discharge) must be calculated. Neglecting the small variations in the upstream and downstream reservoirs' water levels resulting from variations in upstream turbine discharges, an iterative procedure can be implemented to sequentially calculate the turbine discharge and generation of the unit in question. This iterative procedure, however, will yield the generation of one unit, and a similar procedures must be sequentially performed to calculate generation and the corresponding turbine discharges for all other operating units in the facility. Now, since the turbine discharges from all other units' affects the turbine discharge of the first unit, the above procedure must be repeated until the error of estimating the head is acceptable. Note that this procedure does not yield the optimal loading for each unit in the generating facility. For this reason, and as will be discussed in Section 4.5 and 4.6, a static plant unit commitment program (utilizing a dynamic programming algorithm) was used to find the optimal unit loading for a given facility loading and water levels conditions. Output from SPUC was used to derive "plant" characteristic curves that were used to model generation as a function of plant discharge.

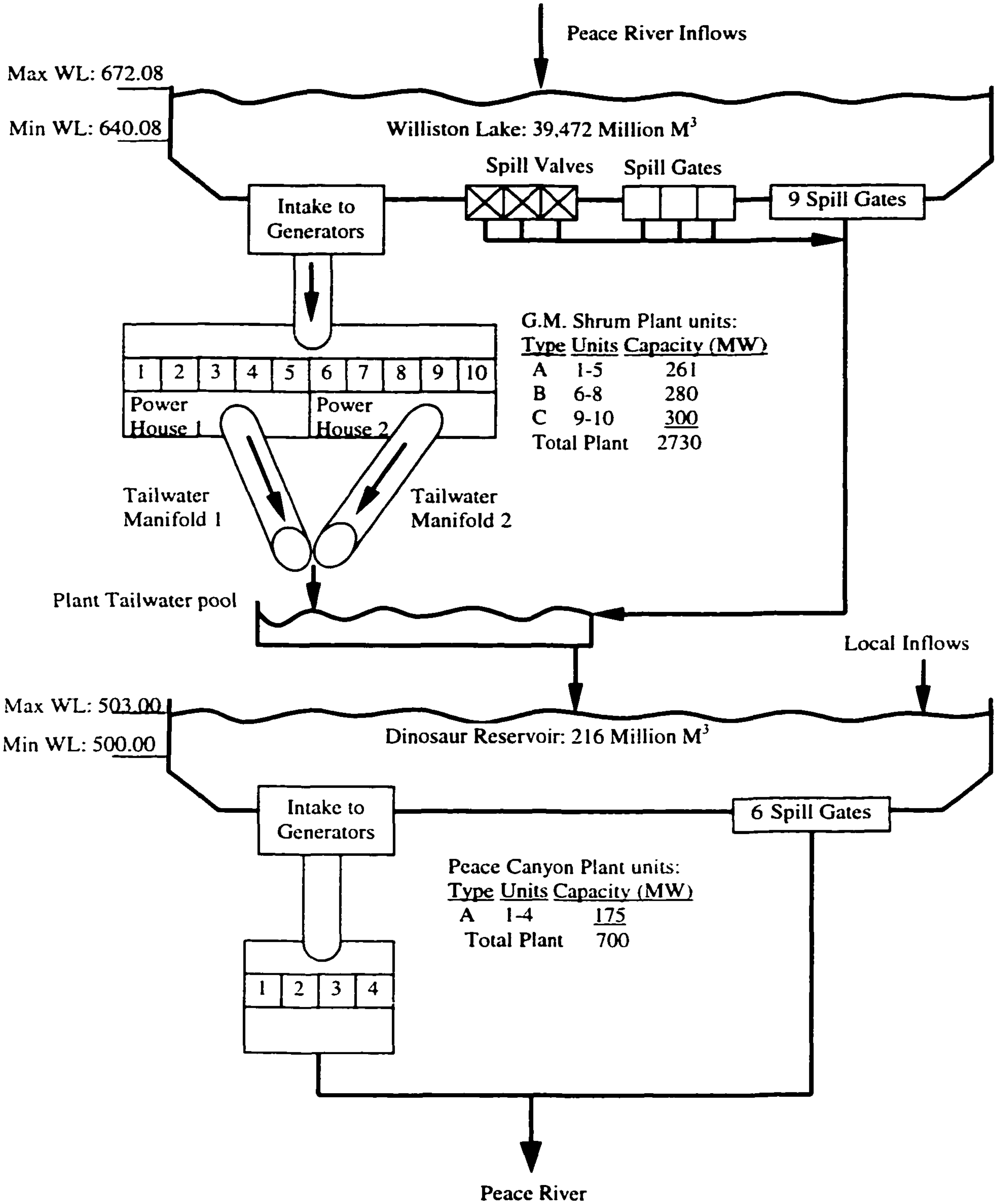


Figure G.1. Schematic Layout of the Peace River Hydroelectric Facilities

G.2 The Columbia River System

STOM models two of the major hydroelectric installations on the Canadian Columbia River system: Mica and Revelstoke on the upper Columbia; and Seven Mile and Waneta on the Pend D'Oreille River system, which joins the Columbia River just north of the Canada/U.S. border.

G.2.1. The Upper Columbia: Mica and Revelstoke Hydroelectric System

The Columbia River is the fourth-largest river in North America. The headwaters of the Columbia River springs in British Columbia just west of the southern part of the Canadian Rocky Mountains. The Columbia River is an international river system that has been heavily developed for hydropower generation both in its Canadian and U.S. reaches. Of concern to this thesis are the two uppermost major generating and water storage facilities: the Mica generating complex and the Kinbasket Lake and the Revelstoke generating facility and reservoir. The Kinbasket Lake, created by the 243 meter high Mica Dam, constructed as part of the Columbia River Treaty with the U.S., is the second largest storage reservoir operated by B.C. Hydro. It has a surface area of 430 km^2 and live storage of about 14.8 billion cubic meters. The catchment area of the Kinbasket Lake is about 21.000 km^2, and it yields an estimated average runoff of 586 m^3/s. The inflows have been estimated to range from about 3,200 m^3/s to less than 120 m^3/s. The Revelstoke reservoir total storage capacity is about 5.3 billion cubic meters, but it is operated as run of river plant except during severe drought conditions. The average local inflow, from a local catchment area of about 5,500 km^2, has been estimated at 221 m^3/s, with a range between 1133 and 43 m^3/s. Water from the Kinbasket Lake is passed to the Mica plant, which is the third largest generating facility in the B.C. Hydro system with a total generating capacity of 1843 MW. Outflows from the Mica plant are discharged and stored in the Revelstoke Reservoir. The Revelstoke generating capacity is the second largest generating facility at 2000 MW. It discharges to the Arrow Lake formed by the Keenleyside Dam, which was constructed as part of the Columbia River Treaty with the U.S. Figure G.2 illustrates the schematic layout of the Mica and the Revelstoke generating facilities and their storage reservoirs on the Columbia River. It can be seen that both the Mica and Revelstoke generating facilities include provision for the installations of two additional units for future expansion. The Mica and Revelstoke projects are operated in hydraulic balance. With no minimum release requirements, other than for physical characteristics and aesthetic reasons during daylight hours, both generating facilities enjoy one of the highest operational flexibility in the B.C. Hydro system. However drafting the Kinbasket Lake affects logging operations and recreational uses, and special provisions to accommodate these uses are allowed for in long-term operations planning.

G.2.2. The Pend D'Oreille Hydroelectric System

B.C. Hydro operates the Seven Mile and Waneta hydroelectric facilities on the Pend D'Oreille River. The Seven Mile plant receives its inflows from the Boundary generating facility, which is owned and operated by Seattle City Light in the U.S. The live storage capacity of the Seven Mile reservoir is about 60 million cubic meters, while the live storage of the Waneta reservoir is about 5 million cubic meters. The Seven Mile generating facility is owned by the West Kootenay Power Company and is operated by B.C. Hydro by special agreement, while the Waneta generating facilities are owned by Cominco Company and is operated by a special agreement. The Seven Mile generating facility has three units with total generating capacity of 600 MW, while the Waneta generating facility has four generating units with total capacity of 360 MW. The Seven Mile discharges to the Waneta reservoir, while Waneta discharges to the main stem of the Columbia River, just before it crosses the Canadian/U.S. international boundary. The water level of the Waneta reservoir affects head of the Seven Mile plant, while the flow level at the Columbia River affects head of the Waneta plant. The two generating facilities are normally operated in hydraulic balance, although spills from Waneta are more frequent for two main reasons. First, the size of the Waneta reservoir is small, which gives rise to rapid fluctuations in its water level and in some instances forcing spills to occur. Second, the Seven Mile generating facility is operated in response to flows originating in Boundary (in the U.S.) and local inflows. Often, Boundary generation can fluctuate significantly. If the Seven Mile reservoir is at its highest operational level then it becomes necessary to run the Seven Mile generating facility near its maximum level to avoid unnecessary spills. Under such circumstances, and because the Waneta reservoir is small and its generating capacity is smaller than that of Seven Mile, spills at Waneta could become necessary for safety reasons even though the plant is running at its maximum generating capacity. The Seven Mile and Waneta hydroelectric facilities enjoys unconstrained operations, other than constraints imposed by the physical characteristics of the generating and discharge facilities. Figure G.3 illustrates a schematic of the Seven Mile and Waneta generating facilities.

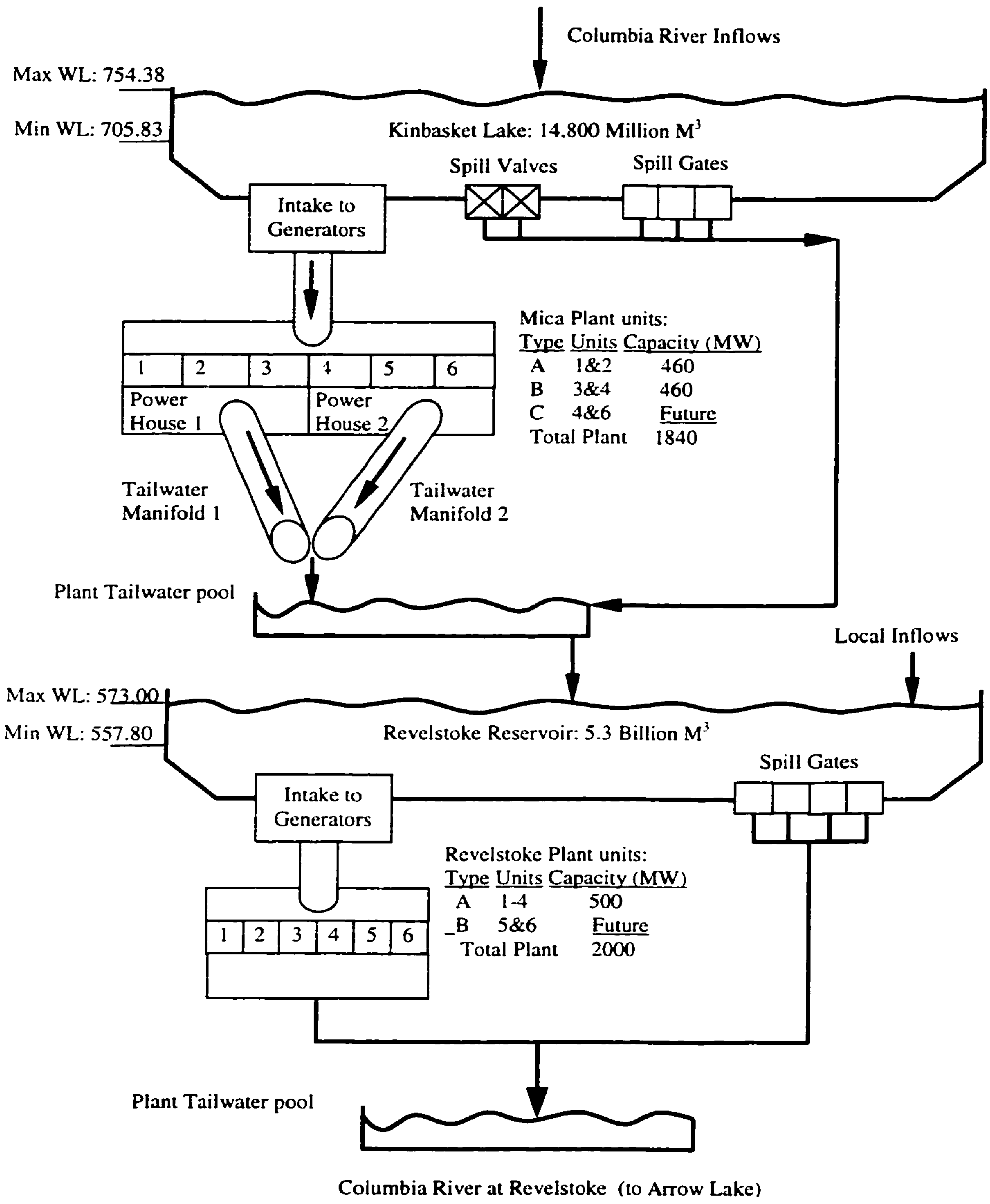


Figure G.2. Schematic Layout of the Upper Columbia Hydroelectric Facilities

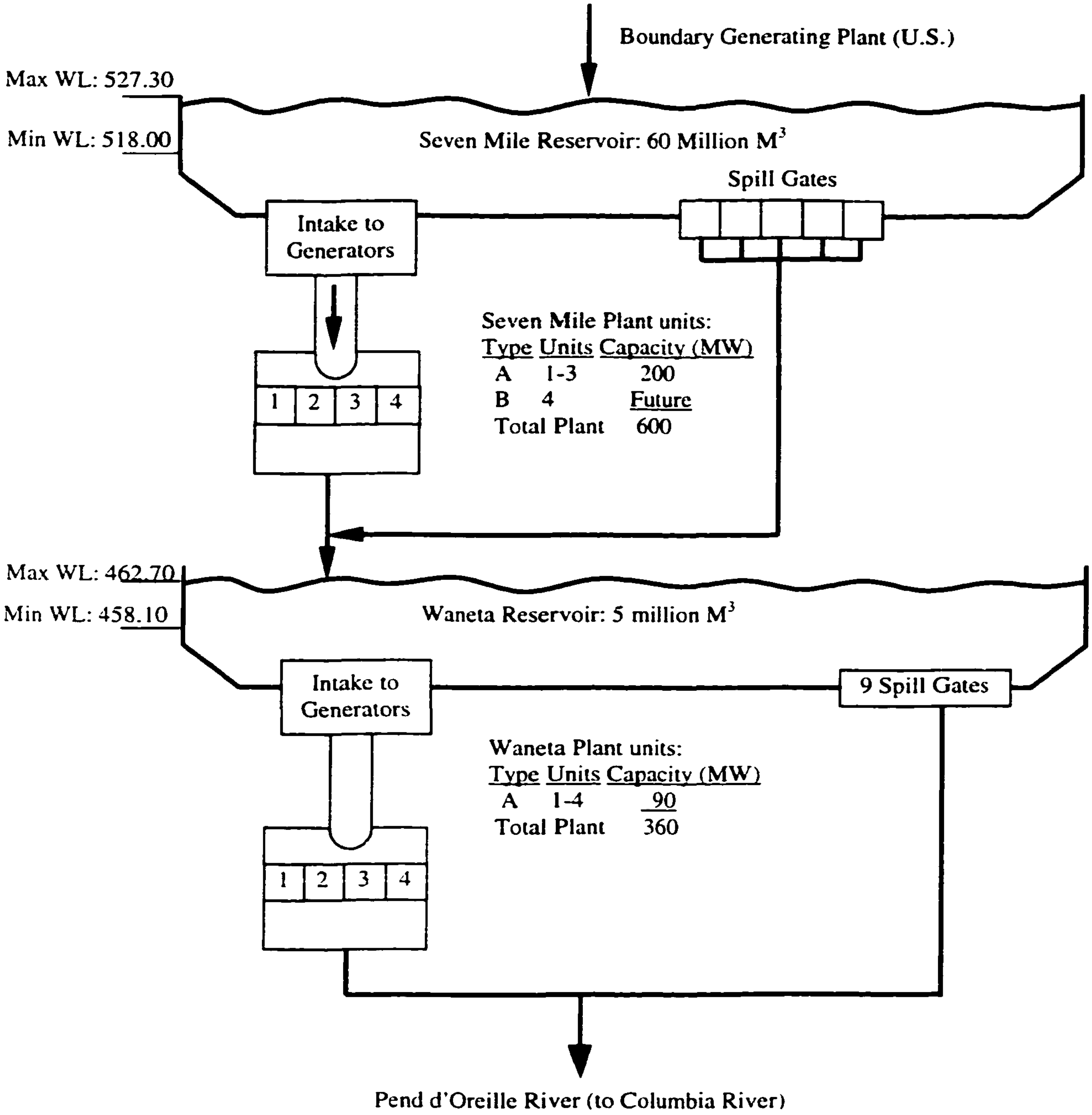


Figure G.3. Schematic Layout of the Pend d'Oreille Hydroelectric Facilities (Columbia River): Seven Mile and Waneta.

G.3. The Stave River System

The Stave River system, illustrated in Figure G.4, is located in the Lower Mainland, east of Vancouver, near Maple Ridge. Flows from the Allouette River are impounded in the Allouette Lake with a storage capacity of 155 million cubic meters. The Allouette Lake is within the Golden Ears Provincial Park and is considered one of the major recreational facilities attracting many residents from the City of Vancouver and other communities in Lower Mainland region. For recreational purposes, water levels of the Allouette Lake are restricted to be above 121.25 for the period between Victoria Day and Labour Day holidays. In addition, minimum fish flow requirements dictate the release of 0.06 m^3/s at the dam and a minimum flow of 0.7 m^3/s further downstream of the dam. Water to the Allouette powerhouse is diverted through a tunnel leading to the Stave Lake. While average annual inflows are in the order of 20 m^3/s, large flood flows could occur late in the fall. As with most hydroelectric facilities near residential areas, the Allouette Lake is operated for flood control purposes as well.

The second hydroelectric facility in the Stave River system is Stave Falls powerhouse. Currently the Stave Falls powerhouse is under redevelopment to raise the generation capacity from 50 to 90 MW. Operation of the Stave facilities is closely coordinated with the downstream plant (Ruskin) for fisheries purposes in the period between October 1st and July 15th. Total inflows to the Stave Lake totals average, 122 m^3/s, of which 21 m^3/s originates from the Allouette's turbine discharges. Peak inflows to the Stave Lake occur as a result of intense rainfall storms in late fall. Other operating constraints are currently being negotiated with the Department of Fisheries and other stakeholders under the newly formed Water Use Plan process.

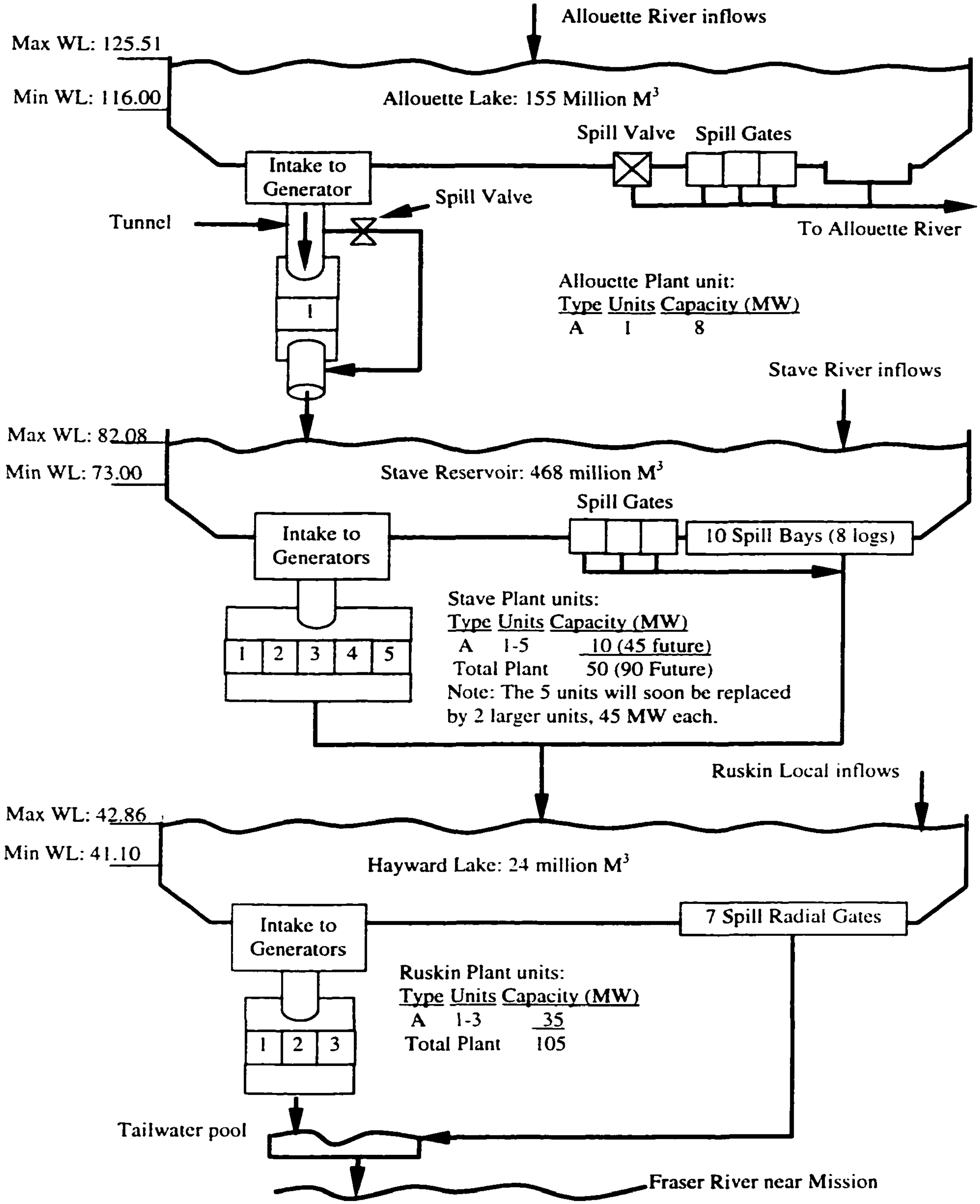


Figure G.4. Schematic Layout of the Stave River System Hydroelectric Facilities.

The main operating constraints at Ruskin, the third facility in the Stave River system, consists of block water releases for fish during October and November, and minimum fish flow releases of 38.3 m^3/s for the period December to April. With little local inflows, inflows to Hayward Lake originate from Stave Falls releases. The Lake's water level fluctuates throughout the year to allow peaking at the plant during high load hours. This results in a drop of reservoir levels of about 3 meters. During the high flow season in the Fraser River, and during high tides, tailwater pool levels becomes high, thereby reducing the gross head on the Ruskin generating units.

G.4 The Bridge River System

The Bridge River Basin is located in the Coast Mountains, and it contains the third largest set of hydroelectric facilities in the B.C. Hydro system. Inflows averaging 40 m^3/s, emanating from glacial and snowmelt in spring and summer are impounded in the Downton Lake on the Upper Bridge River, with an additional 51 m^3/s into Carpenter Lake, in the lower reaches of the river. As illustrated in Figure G.5, the Downton Lake feeds the 24 MW La Joie generating station, which discharges to the Carpenter Lake. The Carpenter Lake waters are diverted out of the Bridge River through two tunnels which feed two generating stations to produces 480 MWHr. The Bridge generating stations discharges to Seton Lake, which feeds the 42 MW Seton generating station that discharges to the Fraser River near Lillooet. As it can be noted from the operations ranges for maximum and minimum water levels of the three reservoirs, the Seton Lake is restricted to about 15-cm fluctuations throughout the year.

Aside from restrictions on the La Joie turbine's ramping rate when Carpenter Lake elevations are low, and the gated ramp rate on the Bridge for public safety, bank stability and fisheries purposes, operation of the two hydroelectric facilities are unrestricted. However, the story for Seton is different, where fish flow releases and ramping rate schedules are required to accommodate upstream and downstream fish migration. In addition, irrigation users and fisheries agencies must be notified when either the reservoir's levels or Seton canal's water levels are lowered below a certain level. Under certain operational conditions a hydraulic jump in the intake penstock could occur, which requires careful monitoring of production of the generating unit. As with the Stave River system, a Water Use Plan process is currently underway to define operation procedures for the Bridge hydroelectric system.

The other feature that makes the Bridge generating facility different from other facilities in the B.C. Hydro system, is the high head (410 m) and high head losses in tunnels and the branching penstocks leading to the jet impulse turbines used in this facility. These features required consideration of net rather than gross head modeling in SPUC as discussed in Section 4.5.

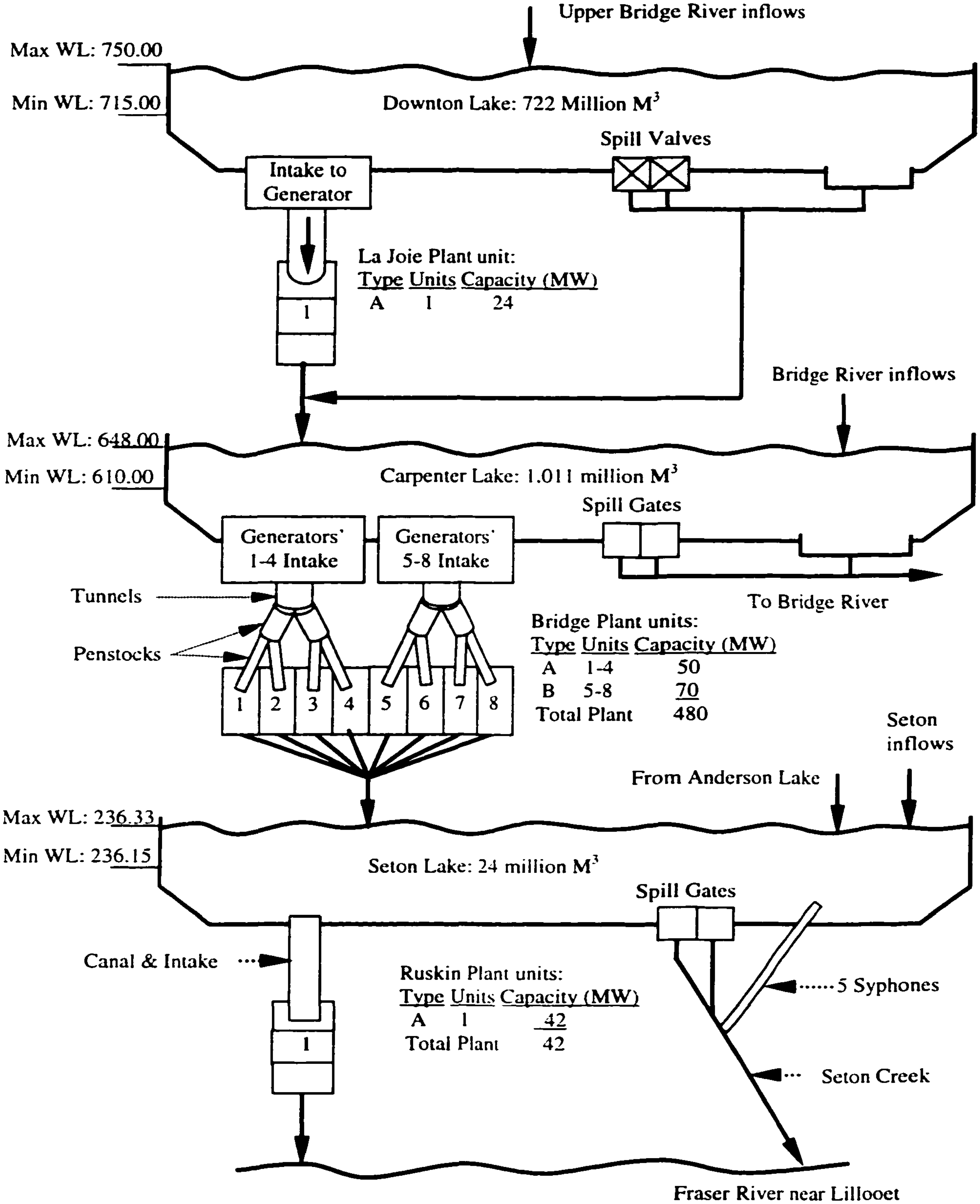


Figure G.5. Schematic Layout of the Bridge River System Hydroelectric Facilities.

G.5 The Campbell River System

Famous for its world class fisheries and its recreational and sporting potentials, the hydroelectric facilities in Campbell River in Vancouver Island are among the most restricted in the B.C. Hydro system. The river system is a spawning haven for all five species of Pacific Salmon, and both summer and winter runs of Steelhead. Sport and recreational activities are as diverse as the fish species that the river supports, and includes fishing and fish viewing, kayaking, hiking, boating, etc, alongside numerous camping areas. Operations of hydroelectric facilities in this river system are constrained by minimum flows and rate of flow velocity change requirements, as well as limitations on draw down and water levels during summer months. In addition, fluctuations in water levels of the lower reservoirs are necessary in order to balance water flow through the turbines.

The hydroelectric system consists of three generating stations and several reservoirs, as shown in Figure G.6. Inflows to Buttle Lake and Campbell Lakes originate from mountains of central Vancouver Island and includes diversions of the Heber Creek and the Qunisam and Salmon Rivers. The diversions impact fisheries, and minimum flows are required (by water license) to alleviate these impacts. Flows can be flashy due to rapid snowmelt during mild winter storms. Flows from Buttle and Upper Campbell Lakes discharge through the Strathcona generating facility (56 MW) into Lower Campbell Lake, which discharges through the 47 MW Ladore generating facility that discharges into the John Hart reservoir. The 126 MW John Hart generating facility discharges to the lower reaches of the Campbell River, which discharges into the Strait of Georgia. Local inflows to the John Hart reservoir are small, however, a minimum flow of 34 m^3/s is maintained for fisheries, and the reservoir is restricted to a draw down of 1.2 meters.

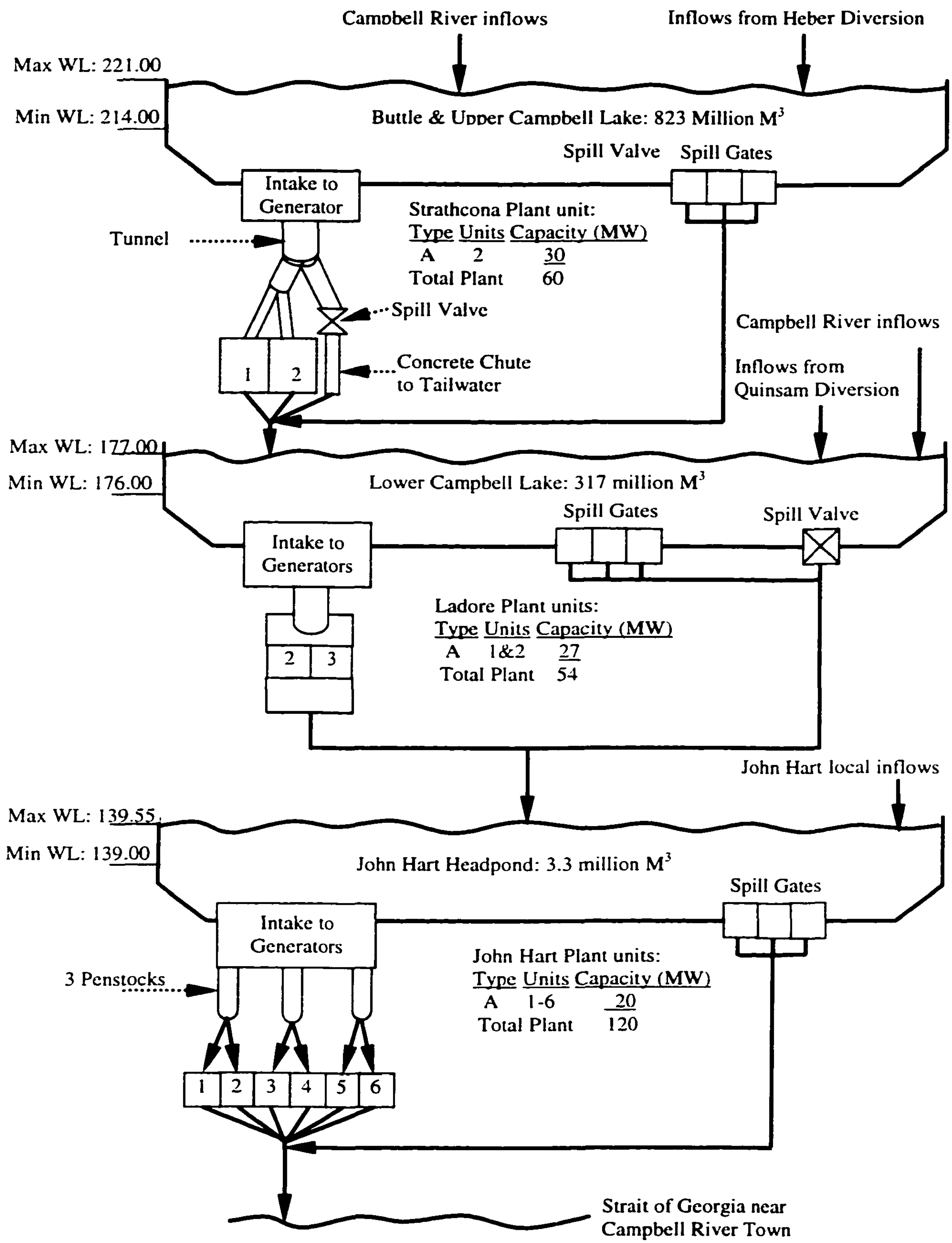


Figure G.6. Schematic Layout of the Campbell River System Hydroelectric Facilities.

G.6 The Cheakamus River System

The Cheakamus River is a coastal river system that discharges to the Squamish River. It is located at about 35 km North of Squamish, and about 135 km North of Vancouver. The Cheakamus dam that impounds water in the Daisy reservoir regulates the Cheakamus river for two purposes: power generation and flood control. The Cheakamus power generation facility, located on the Squamish River, is a 155 MW off-summer peaking, high head (343m) facility that receives flows diverted from Daisy reservoir through a tunnel and two penstocks 11 km in length, as shown in Figure G.7. Storage of the Daisy reservoir is about 46 million m^3 and is subject to very rapid draw-down and filling during adverse weather and heavy rains from September to December, and rapid snowmelt from May to August. Drawing the reservoir down before the fall season alleviates flooding risks. In addition operation of the reservoir has been heavily influenced by the latest Water Use Plan that was adopted recently. The Plan specifies a flow regime for the Cheakamus River to be followed at the dam site to maintain fish and fish habitat. The regime relies on spilling a certain percentage of previous-day inflows. If this percentage is not sufficient, then minimum flows should be maintained at all times. In addition, the total flows discharged through the turbines, in any given year are required to comply with the water license limit.

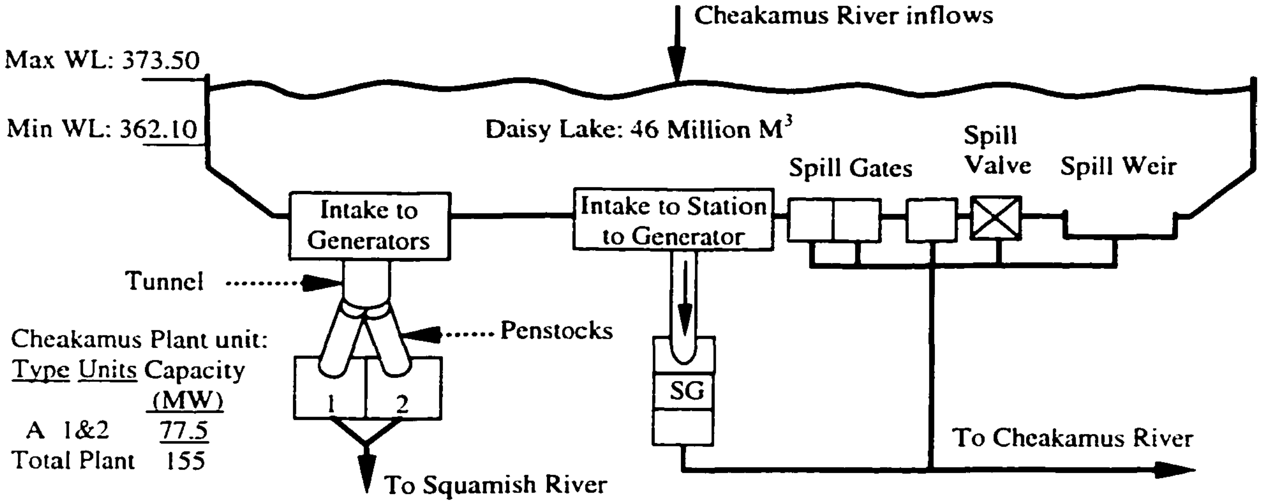


Figure G.7. Schematic Layout of the Cheakamus River System Hydroelectric Facilities.

G.7 The Clowhom River System

The Clowhom River experiences similar flow patterns as the Cheakamus River. Storage capacity of the Clowhom Lake totals 105 million cubic meters and it discharges into the 33 MW Clowhom generating facility. The facility is operated during peak load hours and discharges to the Salmon Inlet, 35 km north of Sechelt in the Sunshine Coast. The mode of operation results in continuous fluctuations in the lake water levels. Currently, the hydroelectric facilities are operated with no constraints.

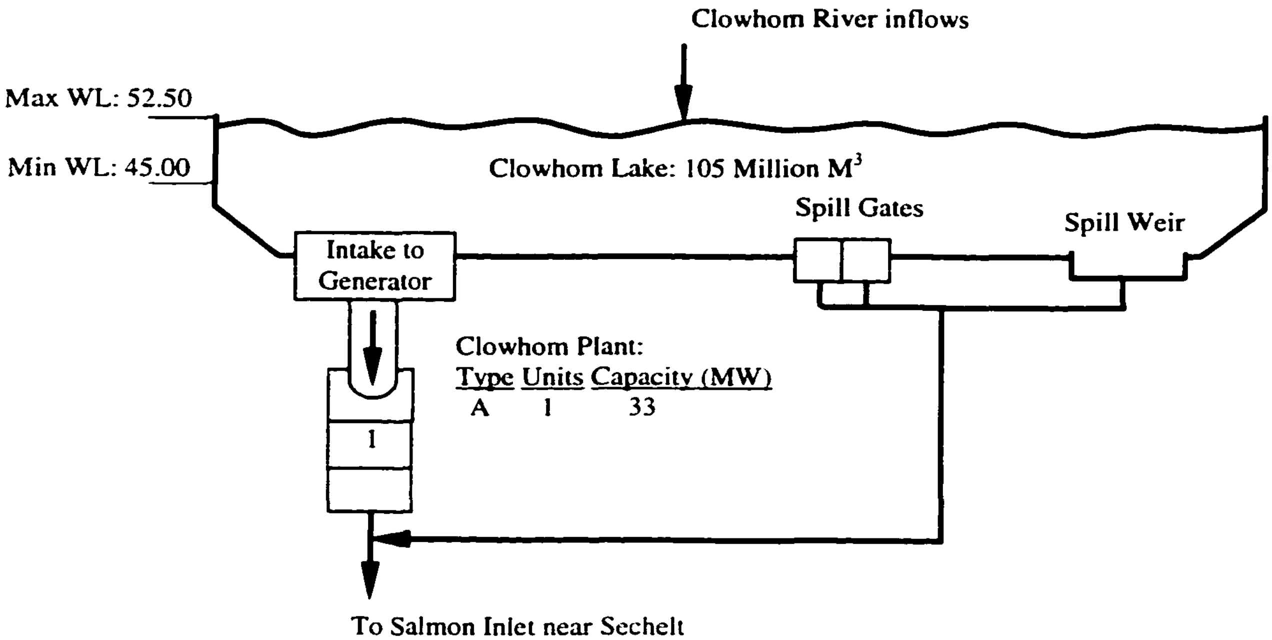


Figure G.8. Schematic Layout of the Clowhom River System Hydroelectric Facilities.

G.8 The Wahleach River System

The Wahleach River system is located 30 km west of Hope, and it drains a high alpine basin. Inflows are stored in the Jones Lake, which discharges through a penstock into the Wahleach generating facility near the Fraser River as shown in Figure G.9. The water column head on the Wahleach powerhouse is the highest (620 m) in the B.C. Hydro system, and for each 1 m^3/s of turbine flow the powerhouse generates about 4.8 MW. Releases from the reservoir are shared between power and flows to sustain fish stocks every odd year. Fish flows are diverted to spawning channels with schedules to suite fish spawning, incubation and out-migration seasons. The site also contains recreational facilities operated by B.C. Hydro.

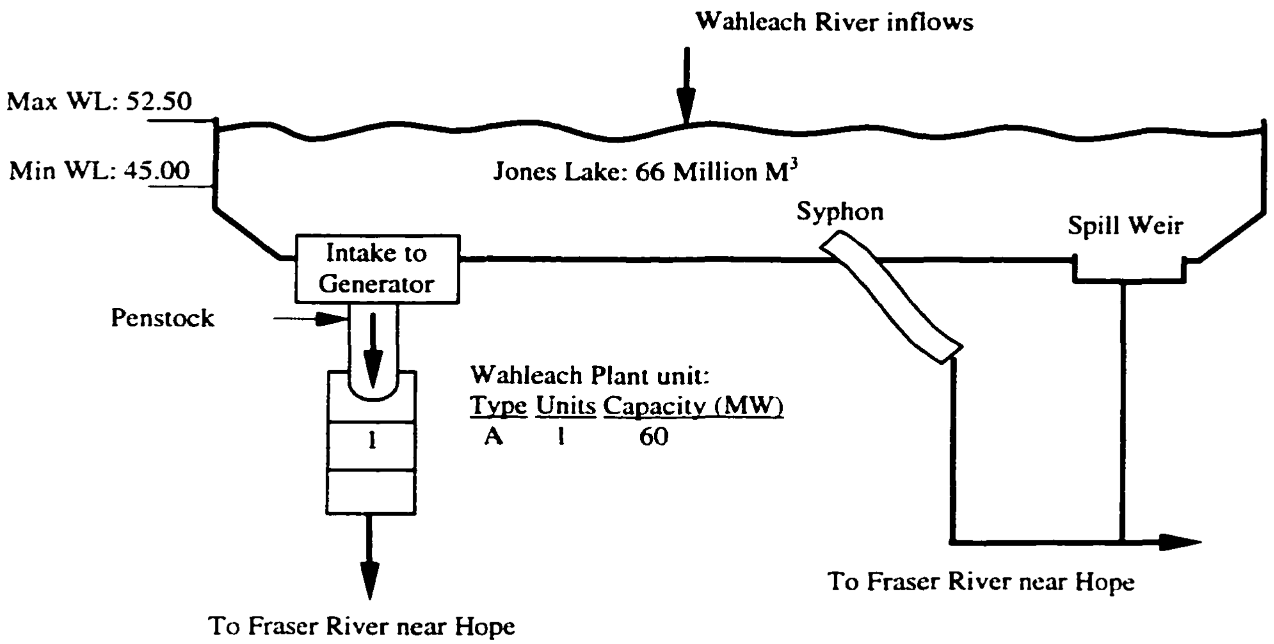


Figure G.9. Schematic Layout of the Wahleach River System Hydroelectric Facilities.

G.9 The Ash River System

The Ash River is located near Port Alberni in Vancouver Island. The river flows are stored in Elsie Lake, which discharges into a 7.4 km pipeline that drops 250 meters to a 25 MW powerhouse on the shores of the Great Central Lake. As shown in Figure G.10, the hydroelectric facility is equipped with a single spill valve that is used to maintain fisheries in the river. Inflows occur as result of snowmelt in May with the regular smooth peaky characteristic, while much higher peak flood flows occur during November's rainstorms. From October to May the reservoir is typically full and generation at maximum capacity is maintained, but once the reservoir water levels are drafted to a minimum level of 320 meters, generation is curtailed down to 10 MW to conserve water for fish.

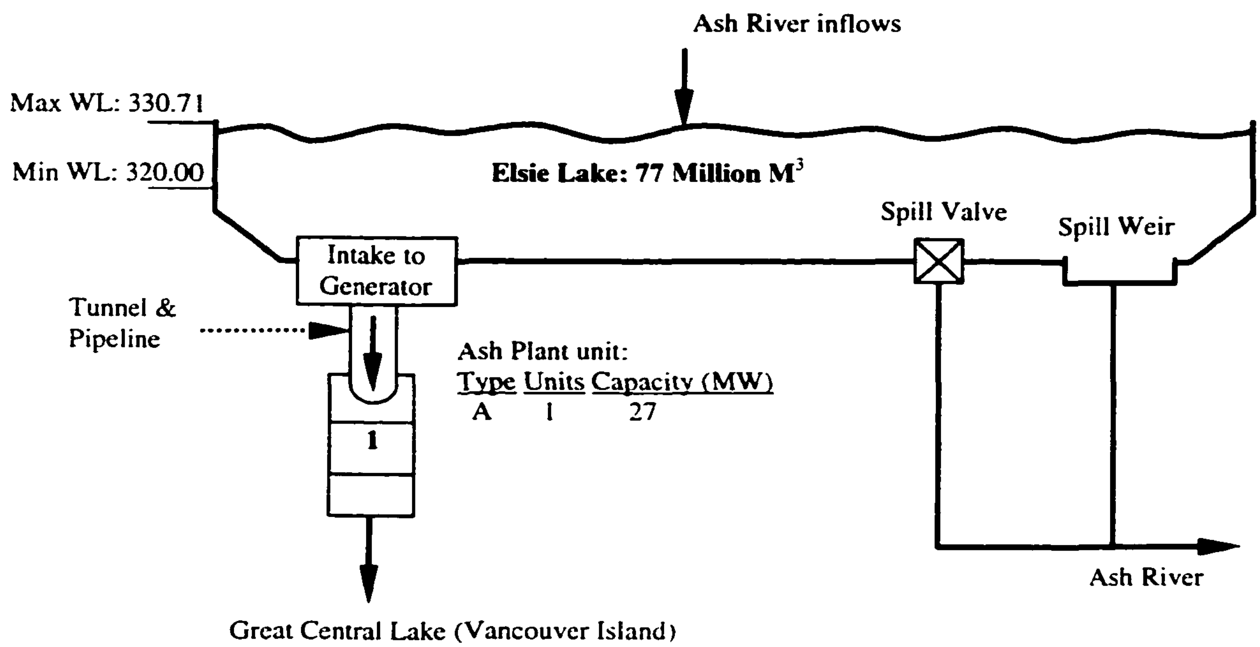


Figure G.10. Schematic Layout of the Ash River System Hydroelectric Facilities.

G.10 Emerging Operational Issues

It should be noted that although not mentioned as an operating constraint in many river systems, each hydroelectric facility is constrained by an annual water license issued by British Columbia Provincial Government. It should also be noted that the B.C. Hydro system currently enjoys significantly more flexibility than many of its counterparts elsewhere in the World, particularly those in the Pacific Northwest, U.S.A.

Within the next few years, the Water Use Plan (WUP) process could define more operational constrains that could take away some of flexibility that B.C. Hydro currently enjoys. The goal of the Water Use Plan process "is to achieve consensus on a set of operating rules for each facility that satisfy the full range of water-usewater use interests at stake, while respecting legislative and other boundaries." (Rosenau et al. 1998). The Provincial Government's objectives for WUP are to protect fish and aquatic habitat; to consider flood control; to consider power generation; and to consider relevant First Nation issues.

As outlined in Rosenau's paper, the WUP process consists of 14 steps. Upon preliminary review of these steps, it was found that many of them are important with regards the operational decision making process at hydro and for modeling of hydroelectric operations.

In addition to the WUP process, B.C. Hydro is currently involved with what has become an International Standard, the ISO 14001, which involve development of a comprehensive Environmental Management System that aims at monitoring environmental impacts of hydroelectric operations, and with the objective of meeting B.C. Hydro's environmental obligations. B.C. Hydro will attempt to obtain ISO 14001 certification for the majority of the facilities it operates, in the future.